PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, July 10, 2023

TIME: 2:00 p.m. - 5:00 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 2

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T A B L E O F C O N T E N T S

E X A M I N A T I O N S

E X H I B I T S

P R O C E E D I N G S

COMMISSIONER KEMERAIT: Good afternoon. Let us come to order and go on the record.

I am Commissioner Karen M. Kemerait, presiding Commissioner for this hearing, and with me this afternoon are Chair Charlotte Mitchell, Commissioners ToNola D Brown-Bland, Daniel G. Clodfelter, Kimberly W. Duffley, Jeffrey A. Hughes, and Floyd B. McKissick, Jr.

I now call for hearing Docket Number E-34, Sub 54, which is the application of Appalachian State University, doing business as New River Light and Power Company -- that I will refer to going forward as either New River or the Applicant -- for the adjustment of general base rates and charges applicable to electric service; and Docket Number E-34, Sub 55, which is the petition of Appalachian State University, doing business as New River Light and Power, for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses.

On December 22 -- excuse me, on December 22, 2022, the Applicant filed an application with the Commission, pursuant to

North Carolina General Statute §62-13 and §62-134, and Commission Rules R-15, R-117 and R-827, seeking authority to increase its rates for electric service in its service territory in Watauga County, North Carolina, and I will refer to that going forward as the Application for General Rate Case.

On January 11, 2023, the Commission issued an Order establishing a general rate case and suspending rates.

On January 18, 2023, the Applicant filed a Motion to Consolidate Dockets E-34, Subs 54 and 55.

On January 31, 2023, the Commission issued an Order granting the Motion to Consolidate the Dockets.

Appalachian Voices and Nancy LaPlaca petitioned to and have been allowed to intervene in this proceeding.

On March 20, 2023, the Commission issued an Order scheduling hearings, establishing procedural and filing requirements, and requiring customer notice.

On March 28, 2023, the Applicant filed Amended Exhibits B and C to the Application, and the Commission issued an Order requiring corrected customer notice and requiring amended application schedules to be filed.

On April 10, 2023, the Applicant filed updated costs and amended exhibits to the direct testimony of Randall E. Halley.

On April 24, 2023, the Applicant filed the Affidavit of Publication of Customer Notice.

On May 2nd, 2023, the Applicant filed Amended Exhibits A, B, and C, concurrent and proposed rate schedules, and the verified certificate of service of notice to customers.

A public hearing for the purpose of receiving the testimony of public witnesses was held on May 23, 2023, in Boone, North Carolina.

On June 6, 2023, the Public Staff and intervenors Appalachian Voices and Nancy LaPlaca filed their direct testimony.

On June 23, 2023, the Applicant filed its rebuttal testimony.

On July 5th, 2023, the Applicant filed an Agreement and Stipulation of Settlement between itself and the Public Staff.

On July 6, 2023, the Applicant and the

Public Staff filed settlement testimony, and that brings us to this afternoon.

Pursuant to the State Ethics Act, I remind all members of the Commission of their duty to avoid conflicts of interest and inquire if any Commissioner has any known conflict of interest with regard to the matter coming before the Commission.

(No response.)

COMMISSIONER KEMERAIT: Seeing none, please let the record reflect that no conflicts were identified.

I now call for appearances of counsel, beginning with the Applicant.

MR. DROOZ: Good afternoon, Commissioners. My name is David Drooz, representing New River Light and Power. And before my colleague introduces himself, I'd also like to note that, in the audience we have a summer associate, Kimberly Southerland, who is here to observe, and Appalachian State University's in-house counsel, Crawford Cleveland.

MR. STYERS: Good afternoon. My name is Gray Styers from the law firm Fox Rothschild, also serving as co-counsel with Mr. Drooz on behalf of the Applicant, New River Light and Power.

COMMISSIONER KEMERAIT: Good afternoon, Mr. Drooz and Mr. Styers.

Moving to the intervenors, beginning with Appalachian Voices.

MR. JIMINEZ: Good afternoon, Commissioners. Nick Jimenez with the Southern Environmental Law Center for Appalachian Voices.

MR. MAGARIRA: Good afternoon. Munashe Magarira, co-counsel on behalf of Appalachian Voices.

COMMISSIONER KEMERAIT: Good afternoon.

And Ms. LaPlaca?

MS. LaPLACA: Nancy LaPlaca, representing myself as a New River Light and Power customer.

COMMISSIONER KEMERAIT: Good afternoon.

MR. FELLING: Good afternoon, presiding Commissioner Kemerait and Commissioners. Tom Felling, along with Will Freeman and Zeek Creech with the Public Staff, on behalf of the using and consuming public.

COMMISSIONER KEMERAIT: Okay. Good

afternoon.

And before we get started, do any of the parties have any preliminary matters that we need to address?

MR. DROOZ: We would like to correct a typo that is in the Agreement and Stipulation of Settlement that was filed on July 5th of this year. And we have conferred with the Public Staff on this.

On page 4 of that Stipulation, there is a paragraph 16, entitled Accounting Adjustments. And in the third line it refers to a UBIT estimated amount of $364,646. That number is correct. Two lines and five lines below that, the number is incorrect, because there is a transposition of two digits, which says $346,646. That should be $364,646. And that's the only matter we have. Thank you.

COMMISSIONER KEMERAIT: Thank you, and that correction is noted.

MR. STYERS: Commissioner Kemerait?

COMMISSIONER KEMERAIT: And there -- also, there should be a correction a couple of lines down as well.

MR. DROOZ: Thank you, yes, we agree.

COMMISSIONER KEMERAIT: Okay.

MR. STYERS: Ms. Kemerait, just for the record, I would just like to note that New River's witness David Jamison, the vice chancellor of Appalachian State, will be available tomorrow. To the extent that we compress some of the testimony by combining our witnesses, I don't think we will be ending the hearing this afternoon, but Mr. Jamison will not be available until tomorrow morning, but he will be available first thing tomorrow morning.

COMMISSIONER KEMERAIT: Thank you, Mr. Styers.

Are there any preliminary matters that need to be addressed from the intervenors or from the Public Staff?

MR. MAGARIRA: Commissioner Kemerait, one preliminary matter from Appalachian Voices. For the record, Munashe Magarira on behalf of Appalachian Voices. Appalachian Voices would like to make a motion for leave to offer live supplemental testimony on the stipulation. If the Commission would permit it at this time, I have some additional remarks regarding this motion.

COMMISSIONER KEMERAIT: Please go ahead with your additional remarks.

MR. MAGARIRA: Okay. Thank you. So the Agreement and Stipulation of Agreement between the Public Staff and New River, along with some of the testimony filed by the Public Staff, New River was filed July 6th, as Commission knows; however, that's only two business days prior to the commencement of this hearing.

By it's own terms, the Stipulation addresses all remaining issues of disagreement as between those two parties. App Voices believes there would be a benefit to hearing additional expert opinion and perspectives on the Stipulation, given the comprehensiveness of the Stipulation and the complexity of underlying issues.

We would submit the live supplemental testimony would be an appropriate vehicle to address these concerns, given the Stipulation was filed well after the intervenor filing deadline. The scheduling order doesn't contemplate prefiled testimony being submitted in response to stipulation. And had App Voices moved to prefile supplemental testimony, there's a possibility the hearing could have been pushed back.

We are mindful, obviously, of the constraints on the Commission's schedule, so we didn't want to do that. We are also aware of the equities also at, I guess, a case in proceeding. We're aware, obviously, several witnesses and parties that have traveled today and didn't want to affect that.

Moreover, if App Voices' motion were granted, we believe it would help put the parties on a more equal footing. New River and Public Staff have filed settlement testimony prepared by the expert witnesses, while App Voices experts have not been afforded the opportunity. And if the Commission were to grant this motion, New River and the Public Staff could conduct cross regarding the live supplemental testimony and/or conduct redirect if applicable.

Indeed, in the proposed witness list that was filed by the parties, New River and Public Staff mentioned that they intended to conduct cross and redirect on any issues that were left unclarified, and/or to just reaffirm the parties' support of the stipulation.

So again, we request, respectfully, that we be given leave to file supplemental testimony on the Stipulation. If it were granted, we would just seek to provide some, I guess, supplemental testimony regarding the cost of capital, I think net billing and cost of service study terms and stipulation, along with some issues that we believe were left unaddressed by the Stipulation, specifically energy efficiency and some capital financing issues, so.

COMMISSIONER KEMERAIT: And does New River have a response to this motion?

MR. DROOZ: Yes. And this is the first we heard of this. I believe that the issues regarding net billing and related to stand-by charge, basic facility charge, and all that, were thoroughly vetted in the prefiled testimony, and there is nothing new in the settlement about that. So it would not be appropriate to have supplemental testimony on those topics.

Same goes for accounting adjustments, because that was not something that Appalachian Voices spoke to in their testimony.

The only thing that their case has that was addressed in the Settlement Stipulation is cost of capital.

And we just ask that, first, any supplemental testimony that is allowed be limited to that topic; and second, that our witnesses have time to confer with counsel and among themselves, and provide any rebuttal to that supplemental testimony after, you know, at least a short time to digest it.

And in case my colleague has anything else, I'll check with him.

COMMISSIONER KEMERAIT: And so for Appalachian Voices' motion, for clarification, is your motion to have live supplemental testimony, and, in addition, written supplemental testimony, or simply live supplemental testimony?

MR. MAGARIRA: Thank you for that clarifying question. We're only asking for live supplemental testimony. And the reason why we're not prefiling supplemental testimony again was the reasons I, sort of, set forth. We didn't want that to impact the hearing date.

I guess if I may respond to

Counsel Drooz's remarks?

COMMISSIONER KEMERAIT: Please go ahead.

MR. MAGARIRA: I guess what I would say in response to that is, again, the Stipulation is, sort of, a comprehensive agreement. And while there are, obviously, some similarities with respect to what the parties testified to in their prefiled testimony and the Stipulation, again, I think the Stipulation needs to be viewed as a whole. And while, again, there are some similarities between those issues, I think, just comprehensively, it does create a different state of facts that exists now, as opposed to when the parties prefiled their testimony. And so I think we would disagree or dispute with the fact that there is enough similarity to, sort of, say that the parties can rest solely on the prefiled testimony that was filed.

Again, we have no objection, obviously, to have Voices or the Public Staff conducting cross examination with respect to our witnesses, but again, for the purposes of clarification, we are not asking to prefile any supplemental testimony. We're merely asking for the opportunity to have our experts be able to opine upon the Stipulation as a global settlement of the remaining issues that were resolved as between the parties, and so would, sort of, resubmit that.

Again, it's a comprehensive settlement. To the extent that there are some similarities in the issues that were put in the prefiled testimony, we would argue that, viewed as a whole, it is a completely different set of facts and law that exists as it stands right now, as opposed to when the parties prefiled the testimony. So that is what I would say in response.

COMMISSIONER KEMERAIT: Before I rule on this, does the Public Staff or Ms. LaPlaca have a response that you would like to provide?

MS. LaPLACA: No.

MR. FELLING: Without weighing into the dispute between counsel, Public Staff has no general objection to that motion, so long as the testimony that's allowed be reasonable in scope and related to the scope of the Settlement Agreement.

COMMISSIONER KEMERAIT: So I'm going to allow Appalachian Voices' motion. The -- it will be live, not written supplemental testimony. And it will be limited to matters that are contained specifically in the settlement agreement. And New River will have an opportunity to cross examine Appalachian Voices' witnesses on this matter.

So with that, are there any additional preliminary matters that the parties wish to address?

MR. STYERS: Just a clarifying question on the Commission's ruling. I -- when will this live testimony be provided? Will it be provided at the same time that the witnesses are called to introduce their prefiled response testimony, is my question.

COMMISSIONER KEMERAIT: Yes, that is correct, and I'm gonna talk about that. I'll address that matter in just a minute.

Before I move on to that issue, are there any additional preliminary matters that need to be addressed?

MR. FELLING: None from the Public Staff.

COMMISSIONER KEMERAIT: So a matter that I -- that the Commission would raise is that we have a new order of witnesses -- and this relates, Mr. Styers, to your question. My understanding is that there is no objection among any of the parties; so if there is an objection, please raise it at this time.

But the order of witnesses are gonna be first, Ms. LaPlaca; second will be testimony from Appalachian Voices witnesses Hoyle and Barnes, and that would be their direct testimony; and then, in addition, their supplemental testimony that's gonna be related specifically to the settlement agreement. And then after Appalachian Voices' witnesses, it will be Public Staff witnesses for direct testimony and settlement testimony. And then, finally, New River witnesses for direct, rebuttal, and settlement testimony.

Are there any objections to this change in the order of witnesses?

MR. DROOZ: No objection.

MR. FELLING: No objection from the Public Staff.

COMMISSIONER KEMERAIT: Okay. Appalachian Voices?

MR. MAGARIRA: No objection from Appalachian Voices.

COMMISSIONER KEMERAIT: Okay. And Ms. LaPlaca?

MS. LaPLACA: No objections.

COMMISSIONER KEMERAIT: Okay. With that, we are now ready to get started with the case, beginning with the Applicant. Apologies, we are not gonna be beginning with the Applicant. We are gonna begin the matter with Ms. LaPlaca.

Whereupon,

NANCY LAPLACA,

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

DIRECT EXAMINATION OF NANCY LaPLACA:

COMMISSIONER KEMERAIT: Please state your name and address for the record, please.

THE WITNESS: My name is Nancy LaPlaca. That's L-A capital P, as in Peter, L-A-C-A, and my address is 239 Wildwood Lane in Boone, North Carolina 28607.

COMMISSIONER KEMERAIT: And, Ms. LaPlaca, do you have any motions in regard to testimony that you would like to have entered into the record?

MS. LaPLACA: Yes. If you could please

enter into the record my direct testimony and also my summary.

COMMISSIONER KEMERAIT: Okay. Seeing no objection, Ms. LaPlaca's direct testimony filed in this docket on June 6, 2023, consisting of 13 pages and 1 exhibit, will be copied into the record as if given orally from the stand, and the summary of her testimony will also be copied into the record as if given orally from the stand.

(LaPlaca Attachment A was identified as it was marked when prefiled.)

(Whereupon, the prefiled direct testimony and prefiled summary of the direct testimony of Nancy LaPlaca 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	)	**DIRECT TESTIMONY OF**
Adjustment of General Base Rates	)	**NANCY LAPLACA**
And Charges Applicable to Electric	)	
Service	)	

BACKGROUND, PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS. My name is Nancy LaPlaca, and I am Principal of LaPlaca and Associates LLC consulting. Both my home and business are located at 239 Wildwood Lane, Boone NC 28607. I own this residence with my partner, Dr. Douglas Goff James. I initially purchased the home in 2017, and Dr. James and I have owned the property together as joint tenants for approximately three to four years. New River Light and Power (NRLP) is our monopoly utility provider. In this testimony, I use the words Appalachian State University (AppState) and NRLP interchangeably, since NRLP is owned by AppState, and thus the State of North Carolina.

Q. WHAT IS YOUR BACKGROUND? Since 2013, I've had my own regulatory consulting business, with a focus on promoting clean energy. I have served as staff for two members of Congress (Morris K. Udall, D-AZ, and Karan English, D-AZ), was the sole Policy Advisor to a public utilities commissioner in AZ 2009-2013), worked as an independent consultant, researcher, strategist, expert witness and intervener in AZ, CO and NC, worked for the U.S.

Department of Energy's Solar Energy Technologies Office (SETO), and created and taught three courses on energy and climate change at Appalachian State University (2019-2020). I started my electricity career in 2006, successfully challenging the permit for a "clean" coal plant (Integrated Gasification Combined Cycle or IGCC) with carbon capture and sequestration (CCS). From my experience with "clean" coal, I learned that such non-solutions – which are really fantasies – are slowing down the transition we need to clean energy. I have both a Juris Doctorate (J.D.) and Bachelor of Fine Arts from Arizona (AZ) State University in Tempe.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY? My testimony addresses the following:

(1) NRLP's current rooftop solar rules, "buy-all sell-all," have predictably resulted in close to zero rooftop solar for NRLP customers, and the proposed net metering charge of $6.17 per installed kilowatt (kW) is so high that few people will be able to afford the charge, resulting in a continuation of zero rooftop solar in Boone;

(2) NRLP's electricity mix is 85% fossil gas, which is 84 times worse for the climate than CO2, with a side helping of staggering health and environmental damages,

(3) NRLP knew from surveys that tying its captive customers to fossil gas until ~2036 – nearly 14 years from now -- is <u>not</u> what its customers want, according to multiple surveys of NRLP customers. While AppState describes itself as "defining sustainability since 1899,[1]" it has

[1] https://sustain.appstate.edu/office/

not lived up to its own sustainability commitments for over a decade, and its lack of transparency and greenwashing could be adding to the mental anguish, depression, and anxiety our youth are suffering.

I. NRLP'S BUY-ALL SELL-ALL ROOFTOP SOLAR RULES HAVE PREDICTABLY RESULTED IN ZERO ROOFTOP SOLAR IN BOONE; AND NRLP'S PROPOSED NET METERING CHARGES ARE SO HIGH ROOFTOP SOLAR WILL CONTINUE TO FLOUNDER

Q: WHY DO YOU PROPOSE THAT NRLP'S ROOFTOP SOLAR RULES HAVE PREDICTABLY RESULTED IN ZERO ROOFTOP SOLAR IN BOONE; AND NRLP'S PROPOSED RULES ARE NOT MUCH BETTER? Look around Boone, do you see any rooftop solar? No. Now head to Asheville, or Durham, or Greensboro, or Charlotte, with far more sensible rooftop solar rules, and you will find lots of solar rooftops. NRLP's current solar scheme, called "buy-all, sell-all," is also known as "forced sale." A customer who purchases rooftop solar *cannot use any of the solar electricity produced – they are forced to sell all of the solar electricity to NRLP at a very reduced rate*. Thus, every kWh generated by a customer's rooftop solar array is a *loss for the customer who installs rooftop solar*.

My household provides a useful example. Dr. James and I refinanced our home ~2019 and put away $30,000 to purchase a 10 kW solar system. Under NRLP's current "forced sale" rules, *we could not use a single kWh that our $30,000 system generated*.[2] Instead, NRLP would sell the (hypothetical) solar kWhs generated by our solar system to our neighbors at NRLP's current retail rate –~12-13 cents/kWh. Thus, every kWh our solar system produced would be a

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[2] Nearly everyone that I have ever explained this to responds in the same way: then why would anyone put up rooftop solar in Boone?

loss to our household budget of ~10 cents/kWh. Under this forced sale scheme, our solar system would *cost almost double the installation price*. Forced sale does not benefit us, our community, or our personal and community resilience – it only serves to kill rooftop solar.

Q: WHAT ARE THE OTHER DETRIMENTS TO NRLP'S BUY-ALL SELL-ALL SOLAR SCHEME? A big problem with NRLP's current buy-all sell-all scheme is that it reduces individual and community resilience. In a climate-changed world, where wildfires, power outages, floods and droughts are all creating increasingly dire situations, communities need resilience, which means redundant systems. For example, when Portland Oregon hit 115 degrees Fahrenheit in June 2021 – almost 40 degrees Fahrenheit above normal,[3] residents without air conditioning needed a cool place to go. Communities all over the U.S. are now discussing resilience, so that residents who lack A/C have somewhere to go when heat waves hit. If most NRLP customers lack A/C, which is likely true, NRLP customers should count on having a "cooling center" where residents can go in case of a dangerous heat wave. In truth, buy-all sell-all *reduces* resilience because it essentially kills rooftop solar/distributed solar.

Q. HOW DOES BUY-ALL SELL-ALL REDUCE, RATHER THAN INCREASE, COMMUNITY RESILIENCE? The purpose of rooftop/distributed solar is to *reduce* grid congestion, *reduce* the cost of generating and distributing electricity, and *increase* community resilience. However, when a solar customer is forced to sell all its solar generation back to the grid, grid congestion increases rather than decreases, thus *reducing* resilience. For example, my

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[3] https://www.nytimes.com/2021/06/27/us/heat-wave-seattle-portland.html#:~:text=the%20main%20story-,Pacific%20Northwest%20Heat%20Wave%20Shatters%20Temperature%20Records,and%20Seattle%20also%20set%20records.

street has ~20 homes, and only a few have A/C, including our home. If Boone suffered a catastrophic heat wave and electric grid outage, our solar system would continue to work, and our neighbors could come over and take shelter from the heat. We want solar not just for ourselves, but for our neighborhood's resilience.[4]

Q. WHY IS RESILIENCE IMPORTANT? The past few years have shown that climate change is affecting our normal weather patterns in increasingly extreme ways. Cities are experiencing more and more heat waves,[5] huge amounts of rain,[6] devastating drought[7] and wildfires.[8] Distributed generation such as rooftop solar, local batteries, electric vehicles (EVs), and energy efficiency allow individuals as well as entire communities to be more resilient to these climate-exacerbated disasters, because it allows individuals and communities to have access to electricity even if the grid goes down.

Q. WHY DOES NRLP'S CURRENT 'GREEN' POWER PROGRAM NOT INCREASE COMMUNITY RESILIENCE FOR ITS CUSTOMERS? NRLP, after over a decade of not actually increasing its clean energy mix -- despite its own stated sustainability goals,[9] signed a contract to purchase power from a hydropower plant starting in January 2022. While hydropower is better than fossil gas or coal, it still arrives in Boone via power lines from a great distance, and thus does nothing for community resilience. If the grid goes down, Boone and NRLP customers will have no power. Local power like rooftop solar means increased resilience, and we are seeing

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[4] https://www.phoenixnewtimes.com/news/blackout-during-heat-wave-would-be-killer-mixture-for-phoenix-study-says-16311996
[5] https://www.nytimes.com/2023/04/25/climate/extreme-heat-waves.html
[6] https://www.epa.gov/climate-indicators/climate-change-indicators-heavy-precipitation
[7] https://www.cnn.com/2023/04/20/us/lake-mead-colorado-river-water-releases-climate/index.html
[8] https://www.nytimes.com/2023/06/04/business/allstate-insurance-california.html
[9] https://sustain.appstate.edu/academics/research/

this over and over in climate disasters. As we are all finding out in our climate-changed world, having electricity can be the difference between life and death.

Q: WHY ARE NRLP'S PROPOSED NET METERING CHARGES TOO HIGH? WHAT HAS HAPPENED IN OTHER JURISDICTIONS WITH SUCH HIGH CHARGES? I have been working in the electricity sector for nearly 20 years across the U.S., and sadly have seen utilities around the U.S. work to undermine rooftop (also called distributed) solar. Sunny Arizona has quite a bit less solar than not-as-sunny North Carolina, and the reason is that utilities in AZ have succeeded in dramatically slowing down solar.[10] A report for utility trade group Edison Electric Institute stated that utilities would be smart to kill rooftop solar early as eventually rooftop solar will seriously impact profits. The report warns of "irreparable damages to revenues and growth prospects" of utilities.[11]

At the public hearing on this docket (E-34, Sub 54) on 5/23/23 at the Watauga County Courthouse, I stated[12] that in 2015, AZ utility Salt River Project (SRP) imposed a $50 per month fee for rooftop solar customers in its territory in central and north Phoenix, and solar installations fell by 95%. Arizona's largest utility, Arizona Public Service (APS), saw a similar precipitous drop in residential solar installations after changing solar reimbursement so that it was no longer financially viable.[13] A February 2023 article in Grist noted:

> "In 2015, the rooftop solar industry in Maricopa County, Arizona, dried up almost overnight. That year, the Salt River Project, or SRP, a state-owned electric utility that serves about 2 million customers in the Phoenix metropolitan area, set new rates for

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[10] See Attachment A for graphics that show the relative amounts of solar in AZ and NC, and a slide from an APS investor presentation that shows the precipitous decline in solar installations.
[11] https://grist.org/climate-energy/solar-panels-could-destroy-u-s-utilities-according-to-u-s-utilities/
[12] I had permission from NCUC attorneys to make a comment since I had not yet submitted my intervention petition.
[13] https://grist.org/energy/utility-monopolies-are-hurting-rooftop-solar-can-antitrust-lawsuits-rein-them-in/

> rooftop solar owners. Suddenly, generating your own electricity from the sun was expected to cost you $600 more per year on your electric bill than it had the year before. At that rate, paying off the panels could take twice as long.

NRLP should welcome customer electrification, as "electrifying everything" would *increase* electricity sales and revenues. For example, since our household installed two compressors and six mini-splits that run on electricity, as well as two Bolt Electric Vehicles (each EV has 60 kWhs of battery storage), our electricity bill has more than doubled. Electrification of our transportation fleet will add greatly to sales of electricity, and all utilities, including NRLP, will benefit.

II. NRLP'S ELECTRICITY MIX IS 85% FOSSIL GAS, WHICH IS 84 TIMES WORSE FOR THE CLIMATE THAN CO2, WITH A SIDE HELPING OF STAGGERING HEALTH AND ENVIRONMENTAL DAMAGES

Q. HOW HAS NRLP TIED ITS CUSTOMERS TO FOSSIL GAS FOR THE NEXT 15 YEARS? A few years ago, I asked AppState for the contract it signed with NTE Energy in 2016. AppState would not share the document, so I filed the equivalent of a FOIA – Freedom of Information Act request -- to get a copy of the contract. This lack of transparency on such an important sustainability measurement is puzzling. Sadly, it's difficult to get information about NRLP beyond photos of its historic dam.[14] The 2016 contract changed NRLP's wholesale provider from Blue Ridge Electric Membership Coop (BREMCO), which purchased its power mostly from Duke Energy. to NTE Energy, an independent power producer (IPP). NRLP changed its wholesale provider to NTE because its power was cheaper – probably ~30% less

[14] https://nrlp.appstate.edu/

according to newspaper articles.[15] NRLP asserted that this new contract would save money, and while it has saved some money, it has the same flaw as other fossil gas contracts: the amount of fossil gas is finite, fossil gas prices are extremely volatile, and fossil gas (also called methane or CH4) is far, far worse for the climate than carbon dioxide (CO2). Tying NRLP customers to purchasing 85% of its electricity in the form of fossil gas for the next 15 years does not "define sustainability." Climate scientist Kevin Anderson says that *fossil gas is a bridge fuel – to a planet that's four (4) degrees Celsius hotter*.[16] An increase in global average temperatures of four degrees C. would be catastrophic.

Q. WHY IS FOSSIL GAS SO BAD FOR THE CLIMATE? Fossil gas is terrible for the climate because it is ~84 times worse than CO2 in its warming effect.[17] Fossil gas power plants emit approximately half the CO2 that coal power plants emit – but *only if you count the emissions directly from the power plant*.[18] However, because fossil gas/methane is a far more potent greenhouse gas than CO2, it's super-charging climate chaos. According to the Intergovernmental Panel on Climate Change's (IPCC's) 5th Assessment (AR5), issued in 2014, fossil gas is *84 times worse than CO2 for the climate*. Add in methane leakage from production and transportation, as well as health and environmental damages from fracking and gas production, and fossil gas creates more problems than it solves. From the IPCC's AR5 report on page 103, with a table of the values below:

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[15] https://www.bizjournals.com/charlotte/news/2018/09/13/how-this-small-florida-firm-is-making-a-power-play.html
[16] https://www.youtube.com/watch?v=vXEL4ZfDbdE and https://tyndall.ac.uk/people/kevin-anderson/
[17] https://www.greenpeace.org/usa/fighting-climate-chaos/issues/natural-gas/
[18] Duke Energy has "converted" many coal plants to run on fossil gas over the past decade, often without a hearing, which does not serve anyone except Duke Energy's profit margin.

> "There is no scientific argument for selecting 100 years compared with other choices (Fuglestvedt et al., 2003; Shine, 2009). *The choice of time horizon is a value judgement* since it depends on the relative weight assigned to effects at different times." (*emphasis added)*

Gas	Lifetime (yrs)	Cumulative forcing over 20 years	Cumulative forcing over 100 years
CO_2	100[19]	1	1
CH_4	12.4	**84**	28

While the utility industry focuses on *direct* emissions of methane from fossil gas power plants, the problem is more complex because methane's effect on global heating is far worse than even CO_2 from coal-fired electricity. We ignore this at our peril, as fossil gas-fired electricity has increased in North Carolina from ~2% of electricity production in the early 2000s to the current 40%, and NRLP's share of fossil gas electricity is a stunning 85%.

Q. WHY IS FOSSIL GAS BAD FOR OUR POCKETBOOKS? The cost of fossil gas has been increasingly volatile since the mid-2000s. Hurricane Katrina resulted in huge cost increases in 2005, with the most recent price spikes in the past year. Nearly all of the fossil gas used in the U.S. is fracked, and fracked gas wells deplete very quickly, 70-90% during the first three years of an average fracked well's production.[20] This means that new wells must be constantly drilled simply to maintain current production. When drilling stops, fossil gas production drops. The Ukraine war, which started in February 2022, added to the volatility of the cost of fossil gas. Since then, exports of U.S. natural gas have increased dramatically as liquefied natural gas or

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[19] 100 years is the timeframe used by the IPCC, however, 25% of all CO_2 is still in the atmosphere after 300-1,000 years, as CO_2 has a very long lifespan. *See* https://climate.nasa.gov/news/2915/the-atmosphere-getting-a-handle-on-carbon-dioxide/#:~:text=Once%20it's%20added%20to%20the,timescale%20of%20many%20human%20lives.

[20] https://www.desmog.com/2021/12/08/david-hughes-shale-optimistic-fracking-forecasts-eia/ and https://www.resilience.org/resilience-author/david-hughes/

LNG. LNG is even worse for the climate,[21] since leakage from production, transportation, compression, and re-gasification[22] are far worse than fossil gas that isn't exported.[23]

An example of the cost benefits of clean energy happened last week in Texas. Wind and solar *saved $11 billion in fuel costs in a single year -- 2022* -- for Texas utility customers. It's highly likely that high fuel costs for fossil gas plants will eventually make them uneconomic. Most of the cost to run a fossil gas power plant is the fuel, and fuel costs are increasingly volatile, with prices spiking during ever-increasing heat waves and cold snaps. Utilities can only "hedge" future fossil gas fuel costs for a fairly short time, perhaps a year or two. Thus, upwards of 70% of the cost to run the fossil gas power plant is unknown. Solar electricity requires no fuel, so that costs are stable compared to fossil gas.

Q. WHAT ARE THE HEALTH AND ENVIRONMENTAL DAMAGES FROM FOSSIL GAS? Studies proving fracking's damages are overwhelming, and the National Institute of Environmental Health Science's website[24] reports on health and environmental damages, water and air pollution, birth defects, toxic chemical exposure and a host of other ills. Despite mounds of evidence showing that fracking is dangerous, destructive, and that it releases super-potent methane gas, utilities have increasingly turned to fossil gas power plants rather than cleaner, cheaper solar and wind. Fracking creates vast amounts of wastewater, emits greenhouse gases

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[21] https://www.theguardian.com/environment/2019/jul/03/booming-lng-industry-could-be-as-bad-for-climate-as-coal-experts-warn
[22] https://environmentaldefence.ca/2022/10/26/dont-buy-the-hype-lng-is-bad-for-the-climate/
[23] https://www.bbc.com/news/science-environment-63457377
[24] https://www.niehs.nih.gov/health/topics/agents/fracking/index.cfm

such as methane, releases toxic air pollutants and generates noise, sometimes 24 hours a day, 365 days a year.[25]

<u>III. NRLP KNEW FROM ITS OWN SURVEYS THAT TYING ITS CAPTIVE CUSTOMERS TO FOSSIL GAS UNTIL ~2036 IS NOT WHAT ITS CUSTOMERS WANT, NOR HAS APPSTATE/NRLP LIVED UP TO ITS OWN SUSTAINABILITY COMMITMENTS,</u>

AppState describes itself as "defining sustainability since 1899,[26]" and yet has close to zero rooftop due to its solar-killing policies, <u>no</u> rebate programs for electrification, <u>no</u> energy efficiency (EE) (except pre-pay, which isn't an EE program but rather a way to avoid shut-offs for non-payment per experts[27]), and lags far behind other NC utilities in offering customer-and-clean-energy friendly programs.[28] *In tying NRLP customers to climate-chaos-inducing fossil gas until the mid-to-late 2030s, NRLP is in fact doing exactly the opposite of what customers want.*

<u>Lancet Study Shows High Depression Rates For Youth Ages 16-25</u>

Our youth are depressed, and this is becoming increasingly obvious. In early 2021, the medical journal Lancet investigated youth climate anxiety, surveying 10,000 young people aged 16-25 across 10 countries. Four of the countries were in the Global South (Brazil, India, Nigeria and the Philippines) and the remaining six were in the Global North (Australia, France, Finland, Portugal, the U.K. and the U.S.). The findings were alarming: *75% of young people surveyed*

[25] https://wvutoday.wvu.edu/stories/2016/12/22/noise-pollution-from-oil-and-gas-development-may-harm-human-health and https://news.berkeley.edu/story_jump/noise-pollution-from-fracking-may-harm-human-health/#:~:text=Fracking%20creates%20noise%20at%20levels,well%2Ddocumented%20public%20health%20hazard.

[26] https://sustain.appstate.edu/office/

[27] https://www.aceee.org/blog/2019/05/prepay-saving-electricity-and-money

[28] DSIRE-USA, the Database of Incentives for Renewable Energy, has a long list of clean energy programs in NC: https://programs.dsireusa.org/system/program/nc

think the future is frightening and 45% say climate concern negatively impacts their day. A stunning 64% of those surveyed said [government] officials are lying about the impact of the measures they are taking, and 58% saying governments are betraying future generations. Sadly, they are spot on. NC universities are also fighting a student suicide crisis.[29] According to the newspaper article:

> "Seven students died by suicide, two fatally overdosed…[o]ver a dozen students and mental health experts described the loss of life at NC State to ABC News as staggering and tragic, as well as a concerning example of national trends in student mental health."

As a 67-year-old "Baby Boomer," I am distressed by what seems to be a lack of concern by AppState's administration, its refusal to face our current climate change crisis, and lack of meaningful action that would at least allow NRLP customers to reduce their *own* carbon footprint. In addition, rooftop solar creates a lot of jobs – according to the U.S. Department of Energy, solar creates 79 times more jobs per megawatt-hour (MWh) than coal-fired generation.[30]

CONCLUSIONS

(1) NRLP's "forced sale" residential solar has resulted in close to zero residential solar installations in Boone over the past decade. NRLP knows that these rules effectively killed rooftop solar in Boone.

[29] https://abcnews.go.com/US/challenging-year-north-carolina-state-confronts-spate-student/story?id=99008743#:~:text=NC%20State%20convened%20a%20mental,November%20to%20examine%20the%20problem.&text=Ahead%20of%20Mental%20Health%20Awareness,making%20a%20priority%20to%20help
[30] https://www.econlib.org/archives/2017/05/solar_power_lot.html

(2) NRLP's proposed solar fee of \$6.17/kW of installed capacity will similarly kill rooftop solar in Boone; these high rates have killed rooftop solar in other jurisdictions, including sunny Arizona.

(3) Despite multiple customer surveys over the past decade, NRLP has ignored the clear directive from its customers to increase local clean energy such as rooftop solar. Sadly, NRLP also has no energy efficiency (EE) or other programs that would help Boone's low-income community. By tying NRLP customers to an electricity mix that's 85% fossil gas, NRLP is super-charging climate chaos, and setting up customers for rapidly increasing bills due to volatile and rising costs of fuel.

While there are several issues that need addressing, such as NRLP's lack of transparency, Ms. LaPlaca has one major recommendation: any net metering charge for rooftop solar customers be capped at no more than \$1.50/kW installed capacity. If NRLP is allowed to charge such a high fee, Boone will continue to have close to zero rooftop solar, despite AppState's assertion that it is "defining sustainability since 1899." Now that we are 124 years beyond 1899, it's time to update NRLP's solar rules to meet the needs of a climate-changed world. After all, AppState graduates dozens of students from its Sustainable Technology department, solar is at the top of the list of sustainable technologies, and our youth need jobs – and hope.

Submitted electronically this 6th day of June, 2023.

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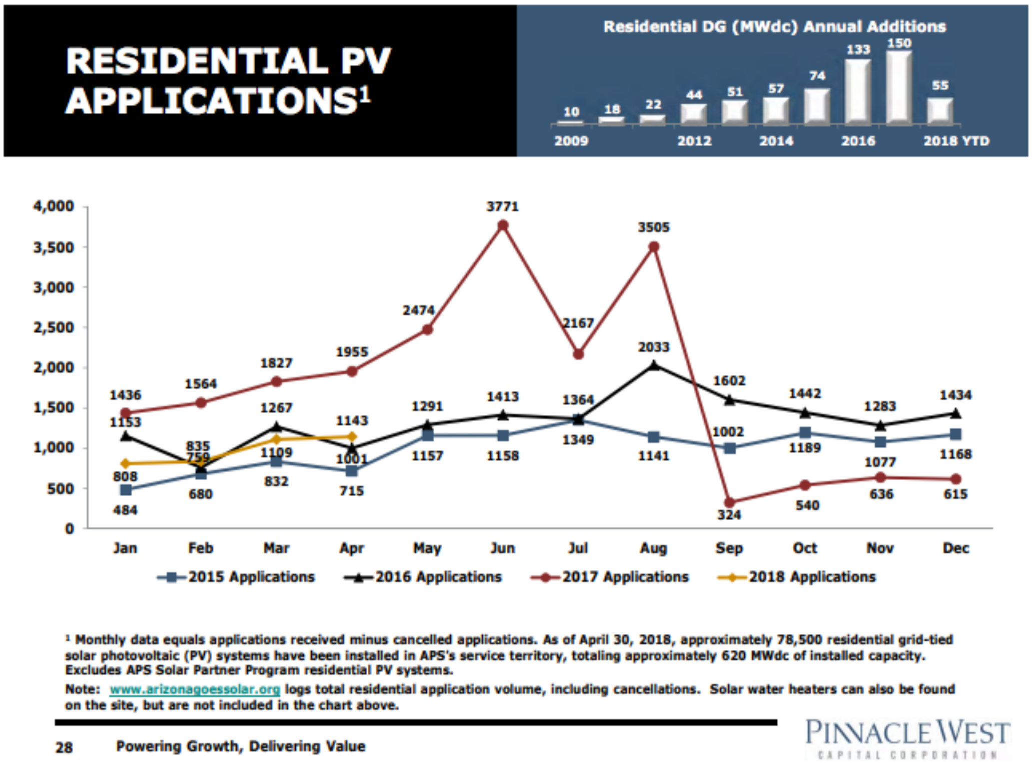
2014, the residential sector is recovering, mostly due to the fact that AZ is so sunny and solar makes sense.[32] Due to solar-killing rules, residential solar applications for APS/Pinnacle West in 2017 fell from a high of 3,505 to 324.



http://s22.q4cdn.com/464697698/files/doc_presentations/2018/Investor-Meetings-May-18-24-2018.pdf, slide 28

[32] SEIA's Arizona page, accessed 6/5/23: https://www.seia.org/state-solar-policy/arizona-solar

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	)	**SUMMARY OF TESTIMONY OF**
Adjustment of General Base Rates	)	**NANCY LAPLACA**
And Charges Applicable to Electric	)	
Service	)	

My name is Nancy LaPlaca, and I am Principal of LaPlaca and Associates LLC consulting. Both my home and business are located at 239 Wildwood Lane, Boone NC 28607. I've worked in energy policy for nearly 20 years, as sole policy advisor to an elected public utilities commissioner, as staff to two congresspersons, worked as an independent consultant, researcher, strategist, expert witness and intervener in AZ, CO and NC, worked for the U.S. Department of Energy, and created and taught three courses on energy and climate change at Appalachian State University (2019-2020). I have a Juris Doctorate (J.D.) and Bachelor of Fine Arts from Arizona (AZ) State University.

The purpose of my testimony is to show that: NRLP's current rooftop solar rules, "buy-all sell-all," have *predictably* resulted in close to zero rooftop solar for NRLP customers; NRLP's proposed net metering charge of $6.17 per installed kilowatt (kW) is so high that few people will be able to afford rooftop solar, resulting in a continuation of zero rooftop solar in Boone; NRLP's electricity mix of 85% fossil gas is 84-86 times worse for the climate than CO2, with a side helping of staggering health and environmental damages; and, most importantly, *<u>NRLP knew from surveys that tying its captive customers to fossil gas until ~2036 – nearly 14 years from now -- is not what its customers want</u>*.

Forced Sale Has Resulted in Zero Rooftop Solar in Boone; and a $6.17/kW Monthly Charge for Solar Customers Will Also Kill Local Solar It's obvious that there is zero rooftop solar in Boone. Although Mr. Miller lists other utilities that use forced sale, those other utilities also have pretty much zero rooftop solar. Bad policies used elsewhere are not a justification for NRLP's poor choices. It's noteworthy that Australia, population 25 million, has as many solar roofs as the U.S.,[1] population 330 million. Only 4% of U.S. homes have solar, while one in three Australian homes have solar.[2] Under forced sale, a customer-site solar system would *cost almost double the installation price*. We need all types of solar, utility-scale, rooftop, community and virtual power plants. Sadly, AppState has not lived up to its own stated sustainability goals to provide utility-scale solar to its customers, despite over 10 years of promises. In 2015, AZ utilities Salt River Project (SRP) and AZ Public Service imposed high monthly fees and changed solar reimbursement, so that rooftop solar installations fell 95%.[3] The same thing will happen in Boone with such a high monthly fee.

NRLP Surveys Repeatedly Show Customers Want Clean Energy NRLP doesn't mention the surveys that it's done over the years, asking its customers what they want. Over and over, customers have indicated they want local, clean energy such as rooftop solar. As a council member in 2020-2021,[4] I spoke with hundreds of people who want clean energy. The Boone

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[1] https://www.nytimes.com/2022/06/08/opinion/environment/defense-production-act-solar-power-australia.html

[2] https://pv-magazine-usa.com/2022/10/28/nearly-4-of-u-s-homes-have-solar-panels-installed/#:~:text=In%202020%2C%203.7%25%20of%20U.S.,reports%20the%20Energy%20Information%20Administration. The U.S. and Australia each have ~3.5-4 million solar installations.

[3] https://grist.org/energy/utility-monopolies-are-hurting-rooftop-solar-can-antitrust-lawsuits-rein-them-in/

[4] In the 2021 election for the Town of Boone, an AppState-affiliated PAC spent $25,000 to elect "friendly" candidates. Despite this huge expenditure in a local race where candidates spend less than $3,000, and winners get ~900 votes, the Appstate PAC's candidates lost badly.

Town Council submitted a letter stating that they want fair net metering,[5] with a fee of no more than $2.00/watt, as did the Blue Ridge Women in Agriculture, which represents over 100 local food producers and at least 200-350 customers who order local food every week.[6] Further, electrification of transportation, and increased use of heat pumps will result in NRLP selling *more* electricity, not less. Since my household installed mini-splits, and have two electric vehicles, our electricity bill has doubled.

Climate Change is Rapidly Getting Worse Climate change is affecting our normal weather patterns in increasingly extreme ways.[7] Increasing heat waves that last longer,[8] catastrophic amounts of rain,[9] devastating drought[10] and wildfires abound.[11] Distributed generation such as rooftop solar, local batteries, electric vehicles (EVs), and energy efficiency allow individuals as well as entire communities to be more resilient to these climate-exacerbated disasters, because local solar provides access to electricity even if the grid goes down. Last week, on Monday, July 3rd, the world experienced the hottest day ever recorded. That record was broken 24 hours later, on July 4th, 2023. People are dying of heat exposure in places like India and the Middle East. Because fossil gas/methane is a far more potent greenhouse gas than CO_2, it's super-charging climate chaos.[12] The Intergovernmental Panel on Climate Change's (IPCC's) 5th Assessment in

[5] While the Boone Sustainability Committee does not particularly support rooftop solar, they are an advisory body *only and has no authority to advocate policy*. Policy decisions are made by the Boone Town Council, which supports fair net metering, i.e. no more than $2.00/watt monthly charge for installed solar.
[6] https://www.brwia.org/home-old.html
[7] https://www.bloomberg.com/graphics/2023-el-nino-climate-change-extreme-weather/?mc_cid=5a6b053497&mc_eid=7e24fc0e68#xj4y7vzkg
[8] https://www.nytimes.com/2023/04/25/climate/extreme-heat-waves.html
[9] https://www.epa.gov/climate-indicators/climate-change-indicators-heavy-precipitation
[10] https://www.cnn.com/2023/04/20/us/lake-mead-colorado-river-water-releases-climate/index.html
[11] https://www.nytimes.com/2023/06/04/business/allstate-insurance-california.html
[12] https://www.greenpeace.org/usa/fighting-climate-chaos/issues/natural-gas/

2014, states fossil gas is *84 times worse than CO2 for the climate*. Climate scientist Kevin Anderson says that *fossil gas is a bridge fuel – to a planet that's four (4) degrees C hotter*.[13]

Clean Energy Saves Money on Fuel, and Most of the Cost to Run a Gas Plant is Fuel

An example of the cost benefits of clean energy recently happened in Texas. Wind and solar *saved $11 billion in fuel costs in a single year -- 2022* -- for Texas utility customers. It's highly likely that high fuel costs for fossil gas plants will eventually make them uneconomic. Most of the cost to run a fossil gas power plant is the fuel, and fuel costs are increasingly volatile, with prices spiking during ever-increasing heat waves and cold snaps. Utilities can only "hedge" future fossil gas fuel costs for a fairly short time, perhaps a year or two. Thus, upwards of 70% of the cost to run the fossil gas power plant is unknown.

CONCLUSIONS

I am an energy policy expert, but first, I'm a human being. I'm distressed that many scientists are alarmed at recent temperature anomalies. There are many young people and children in my life who I love dearly, and who keep me going in this work. Over the past 20 years, I have watched as utilities have killed clean energy over and over, especially local, distributed solutions like rooftop solar and energy efficiency programs. I know that we need both utility and rooftop solar. NRLP customers want rooftop solar for many reasons: reduce toxic emissions, address climate change, provide local jobs, and give our young people hope. That last one, which isn't in any rule or law, is clearly the most important. As a society, we are about to

[13] https://www.youtube.com/watch?v=vXEL4ZfDbdE and https://tyndall.ac.uk/people/kevin-anderson/

find out how climate chaos will interact with society-wide hope and fear about the future. Here are my observations and recommendations:

- NRLP's "forced sale" residential solar has resulted in close to zero residential solar installations in Boone over the past decade, and its proposed solar fee of $6.17/kW of installed capacity will similarly kill rooftop solar in Boone.
- Despite multiple customer surveys over the past decade, NRLP has ignored the clear directive from its customers to increase local clean energy such as rooftop solar.
- By tying NRLP customers to an electricity mix that's 85% fossil gas, NRLP is super-charging climate chaos, and setting up customers for rapidly increasing bills due to volatile and rising costs of fuel.

Submitted electronically this 7th day of July, 2023.

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COMMISSIONER KEMERAIT: Ms. LaPlaca is available for cross examination, beginning with the Public Staff.

MR. FELLING: Commissioner Kemerait, we do not have any questions for this witness. Thank you.

COMMISSIONER KEMERAIT: And then I see that New River has cross examination for Ms. LaPlaca.

MR. DROOZ: And I know when we -- I believe when we filed the witness list sequence and all, we asked that we be the last party to cross the intervenors. Of course, that's -- we'll do whatever you think is appropriate, but that was our request.

COMMISSIONER KEMERAIT: Mr. Drooz, I see that Appalachian Voices has not reserved any cross examination time, unless that has changed, but you have not stated --

MR. JIMINEZ: That's correct.

COMMISSIONER KEMERAIT: -- that you have any cross examination, so it would be New River's cross examination.

MR. DROOZ: We have no cross.

COMMISSIONER KEMERAIT: Okay. So no cross examination from any of the parties.

Are there any questions from the Commission?

(No response.)

COMMISSIONER KEMERAIT: Ms. LaPlaca, there are no questions from the Commission, so I appreciate you coming for the hearing, and you may be excused.

MS. LaPLACA: Thank you.

COMMISSIONER KEMERAIT: Okay. Now we'll move on to Appalachian Voices witnesses.

MR. MAGARIRA: Thank you, Commissioner Kemerait. At this time, Appalachian Voices would like to call Jason Hoyle.

Good afternoon, Mr. Hoyle.

Whereupon,

JASON HOYLE,

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

COMMISSIONER KEMERAIT: Thank you.

MR. MAGARIRA: Thank you, Commissioner Kemerait.

DIRECT EXAMINATION BY MR. MAGARIRA:

Q. Mr. Hoyle, could you state your name, title, and business address for the record?
A. My name is Jason Hoyle. I'm the principal energy policy analyst at EQ Research. My business address is 1155 Kildaire Farm Road, Cary, North Carolina.
Q. Please briefly describe your roles and responsibilities at EQ Research?
A. At EQ Research, I am the lead on our general rate case service product. As part of that job, I review or prepare summaries on rate cases filed by utilities across the country with 50,000 or more customers. And we also prepare regular updates on progress of various rate cases to our clients.
I'm also the lead on our service program for Community Choice Aggregators in California, where I'm in charge of, essentially, preparing filings for integrated resource plans, renewable portfolio procurement plans; handling items such as resource adequacy, reliability, and other, sort of, consulting services in that regard. And I also work on various consulting projects for other clients.
Q. Thank you. Mr. Hoyle, did you cause to be prefiled in Docket Numbers E-34, Sub 54 and Sub 55 on

June 6th direct testimony and two exhibits consisting of the combined total of 62 pages?

A. Yes.

Q. Do you have any corrections you'd like to make to your testimony or exhibits on the stand?

A. No.

Q. So if the questions put to your in your testimony were asked at the hearing today, your answers would be the same?

A. Yes.

Q. Did you also cause to be prefiled in those same two dockets, on July 6th, a summary of your testimony consisting of four pages?

A. Yes.

Q. All right. Thanks. Moving on to the Stipulation, have you had the chance to review the Agreement and Stipulation Agreement between New River Light and Power and the Public Staff filed on July 6th?

A. Yes.

Q. Have you had the chance to review the settlement testimony of Randall Halley filed on behalf of New River in those same two dockets on July 6th?

A. Yes.

Q. Have you had the chance to review the settlement testimony of John R. Hinton and James McLawhorn, both of which were filed on behalf of the Public Staff on July 6th?

A. Yes.

Q. Please briefly describe the Stipulation terms concerning cost of capital.

A. The stipulation terms regarding cost of capital, overall rate of return was 6.15 percent; capital structure, 50 percent equity, 50 percent debt; cost of debt of 3.23 percent; and a return on equity of 9.1 percent.

Q. All right. Please briefly describe the Stipulation's treatment or addressing of energy efficiency and demand side management?

A. The stipulation does not address energy efficiency or demand side management.

Q. What concerns do you have of the Stipulation's cost of capital provisions?

A. My concerns are partly that it's based on a hypothetical capital structure. It is not cost-based. It has, in my opinion, an unreasonably high return on equity.

Q. Okay. What issues do you have with the Stipulation's lack of discussion of energy efficiency and demand side management?

A. I would say that is the issue, is the lack of discussion of energy efficiency and demand side management. These are matters that have come before the Commission before in New River's prior rate case. The Commission's order at that time, to me, at least, indicated some interest in seeing some development of these types of programs.

So far, that development has been minimal. And perhaps it would stop altogether, it's hard to say, but there is nothing in the stipulation that would require the continued pursuit of these sorts of programs.

Q. Thank you.

MR. MAGARIRA: One moment.

Q. Thank you. So in light of these issues and concerns you have identified, what recommendations do you have for the Commission regarding the stipulation?

A. Well, my first recommendation would be that the Commission should reject the stipulation. That it should reject it, because it lacks reference to energy efficiency/demand side management program development. I believe the rate of return, return on equity, and the capital structure are improperly calculated, I suppose is a good enough word, in the stipulation.

MR. MAGARIRA: Okay. Commissioner Kemerait, I would move to have Mr. Hoyle's prefiled direct testimony and exhibits with the correct- -- actually, no corrections made on the stand today, and his prefiled testimony summary be entered in the record as if given orally from the stand, and have the exhibits attached to his prefiled direct testimony identified as premarked. I would also move that Mr. Hoyle's live supplemental testimony that was given from the stand today be moved into the record.

COMMISSIONER KEMERAIT: Seeing no objection, Mr. Hoyle's direct testimony filed on June 6, 2023, consisting of 48 pages will be copied into the record as if given orally from the stand, and the two exhibits attached to the direct testimony will be marked for identification purposes as prefiled, and the live summary will be copied into the record as well.

(Exhibits JWH-1 and JWH-2 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct

testimony and prefiled summary of the
direct testimony of Jason Hoyle were
copied into the record as if given
orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-34, SUB 54
DOCKET NO. E-34, SUB 55

DOCKET NO. E-34, SUB 54	)
	)
In the Matter of Application for General Rate Case	)
	)
DOCKET NO. E-34, SUB 55	)
	)
In the Matter of Petition of Appalachian State University d/b/a New River Light and Power for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses	)

DIRECT TESTIMONY OF

JASON W. HOYLE

ON BEHALF OF

APPALACHIAN VOICES

JUNE 6, 2023

Table of Contents

I. Introduction

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

A. My name is Jason W. Hoyle. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Principal Energy Policy Analyst of EQ Research LLC.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of Appalachian Voices (AV).

Q. Have you previously submitted testimony before the North Carolina Utilities Commission (NCUC or the Commission)?

A. No. I have not previously submitted testimony before the Commission.

Q. Please describe your educational and occupational background.

A. I obtained a Bachelor of Science in Mass Communications with a concentration in print journalism from Appalachian State University in Boone, NC in 2001 and a Master of Business Administration from Appalachian State University in 2003. I was employed at the Appalachian Energy Center and the Center for Economic Research and Policy Analysis in various positions of increasing responsibility for nearly 18 years. I was the lead analyst responsible for due diligence, regulatory compliance analysis, pro forma financial and valuation analysis, including PPA negotiations and innovative carbon financing opportunities for nearly a dozen community-based renewable energy projects on behalf of local governments across North Carolina. My work also included research, analysis, and implementation activities related to a variety of energy policy and related programs such as the N.C. State Energy Plan, the North Carolina Climate Action Plan Advisory Group, U.S. Environmental Protection Agency programs, Climate Action Reserve protocols, as well as a variety of other consulting work performed on behalf of state universities, municipal and county governments, and non-profit corporations. I also served as a faculty member in the Appalachian State University's Department of Sustainable Technology and the Built Environment between 2012 and 2021, where I developed and taught graduate and undergraduate courses on focused on the policy, market, and economic context of utility regulation. These courses covered topics ranging from regulatory oversight roles and the development of electric utility regulation from the later 1800s through the present day, review and analysis of electric utility rates for the purchase and sale of electricity, finance, and environmental attribute markets. While at Appalachian State, I also developed curriculum for and taught professional continuing education courses on renewable energy policy, finance, and regulation that offered AIA Learning Units, engineering Professional Development Hours, CPA (CPE) credits, Continuing Legal Education credits, SWANA Continuing Education Units, and Continuing Forestry Education credits.

I joined EQ Research in early 2022 as a Principal Energy Policy Analyst. In my current position, I lead EQ General Rate Case service which includes preparing and reviewing analyses of rate case filings for electric utilities across the country. I also coordinate EQ Research's regulatory and compliance consulting services for Community Choice Aggregation programs in California, including regulatory monitoring and analysis, compliance reporting, litigation support, and resource procurement planning, including the preparation of integrated resource planning and other resource procurement plans.

I coordinate and contribute to EQ Research's various research projects for clients, provide oversight of EQ Research's electric industry tracking services and consulting projects, and perform customized research and analyses to fulfill client requests. My CV is included as Exhibit JWH-1.

Q. Please describe the purpose of your testimony and how it is organized.

A. My testimony addresses three topics, which I have separated into the following sections:

- Section II addresses the proposed rate of return (ROR), return on equity (ROE), cost of debt, and capital structure Appalachian State University (ASU) d/b/a/ New River Light and Power (NRLP) has submitted for approval; identifies issues with those proposals; recommends an alternative ROR, ROE, cost of debt, and capital structure; recommends that NRLP conduct a discounted cash flow (DCF) analysis following the Commission's final order in this proceeding to better optimize its capital structure and capital funding sources for its operations going forward and for use and incorporation in future general rate cases; and recommends that the Commission require NRLP to make a compliance filing updating its proposed ROR and capital structure following its DCF analysis.

- Section III addresses the establishment of energy efficiency (EE) and demand-side management (DSM) programs by NRLP, which the stipulation adopted in NRLP's last general rate case required and which the Company has failed to establish since then.
- Section IV contains my concluding remarks and summarized recommendations.

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. I am sponsoring Exhibit JWH-1 which contains my CV. I am also sponsoring Exhibit JWH-2 which provides examples of EE/DSM programs from across North Carolina similar to the types of programs identified by NRLP.

Q. Please summarize your recommendations to the Commission regarding NRLP's proposals relating to ROR, ROE, cost of equity, cost of long-term debt, and capital structure.

A. My recommendations are as follows:

- The Commission should direct NRLP to move to actual, cost-based values as a basis for ROE, cost of debt, ROR, and capital structure in this case and in future cases.
- The Commission should direct NRLP to develop a DCF analysis and develop a comprehensive financing strategy that optimizes the capital structure for the utility considering its status as an operating unit of ASU.
- The Commission should direct NRLP to make a compliance filing updating its proposed ROR and capital structure following its DCF analysis.
- The Commission should approve an ROE that reflects the actual cost of obtaining capital that NRLP faces. I recommend using the 5% value as a starting point in setting the approved ROE for NRLP and that the starting point for the allowed ROE be increased by an additional 1.25% to reflect that the rate for bonds would also be adjusted to account for debt service coverage, and I recommend that the Commission approve 6.25% as an ROE for use in setting NRLP's weighted average cost of capital.
- I recommend that the Commission authorize NRLP to use its historical embedded cost of debt of 2.30% in its capital structure and for use in developing its weighted average cost of capital.
- I recommend that the Commission approve the 78.3% equity / 21.7% long-term debt capital structure based on NRLP's actual cost of service.

- I recommend an ROR of 5.39% for NRLP.

Q. Please summarize your recommendations to the Commission regarding the establishment of EE/DSM programs by NRLP.

A. My recommendations are as follows:

- NRLP should formally propose the three EE/DSM programs it has already identified and listed, guided by the program designs discussed in Exhibit JWH-2, as pilot programs of limited duration.
- NRLP should prepare and file an EE/DSM plan that addresses the topics identified herein and that specifically includes a market evaluation, an evaluation of multiple EE/DSM program options, an EM&V plan (that would apply to the pilot programs at a minimum, and ideally to other future programs as well), and a clear timeline with program development milestones. NRLP should develop the EE/DSM plan concurrently with the pilot EE/DSM offerings discussed above and use the plan and the results of the pilots to develop permanent offerings at the end of the pilot period.
- As a complement to the three programs discussed above, NRLP should develop a behavior-based DSM program that allows NRLP to communicate with customers as a means of reducing NRLP load during times of grid stress and during coincident peak hours. The communications could, among other things, inform customers about the three programs discussed above. For maximum effect, given the high

proportion of students in NRLP's service territory, the program should be available to all electricity consumers in NRLP's service territory and not restricted exclusively to NRLP customers. NRLP should develop this as a pilot program as well and evaluate its effectiveness along with the other three pilot programs at the end of the pilot period.

- NRLP should consider adding a program focused on weatherization and building retrofits/upgrades, particularly for older less energy efficient residential units.

II. Return on Equity, Cost of Debt, Rate of Return, and Capital Structure

Q. Please provide a brief overview of the cost of capital sections of your testimony.

A. I review NRLP's proposed, allowed ROE of 9.60%,[1] proposed, allowed overall rate of return ROR of 7.007%, and proposed, hypothetical equity to long-term debt ratio of 52% equity to 48% debt from which NRLP's proposed ROR is derived. I find that NRLP's proposals are unreasonable and unjustified because they are not cost-based, because they violate accepted rate making standards and are benchmarked against

[1] As explained in my testimony, NRLP does not actually face a cost of equity, nor does it benchmark its proposed ROE against comparable utilities facing comparable market risks and demand for capital.

inappropriate industry data, and because they would therefore unjustly burden NRLP's customers and improperly impact the transfer of NRLP profits to the ASU Endowment Fund under North Carolina law.[2]

Q. What do you recommend that the Commission do in response to NRLP's proposals?

A. I recommend that NRLP's proposals relating to cost of equity, cost of long-term debt, and capital structure be rejected by the Commission. Instead, I propose that the Commission approve an allowed rate of return based on NRLP and ASU's actual costs. My recommendation for an improved capital structure for NRLP is in Table JWH-1, below.

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[2] North Carolina law provides for the transfer of NRLP's net profits to the ASU Endowment Fund. N.C.G.S. § 116-35 states that all net profits are to be paid to the Endowment fund. NRLP does not have any input into how Endowment funds are to be allocated; to the extent the Endowment allocates funds for scholarships, then NRLP staff and customers do have a voice in selecting student recipients funded from NRLP net profits. NRLP response to AV 3-9(b). As explained later in this testimony, NRLP excessively and expensively relies on retained earnings to fund its capital projects. This has the effect of increasing costs to customers, including ASU, and of decreasing the net profits available for transfer to the Endowment Fund. ASU has averaged a 4.73% return on Endowment funds. NRLP response to AV 7-1. The excessive use of retained earnings to fund capital projects reduces the transfer and the return on transfers, while at the same time charging ASU, ASU students, and NRLP non-university customers much more for electric service than is reasonable or justified.

Table JWH-1: Proposed ROR for NRLP

Capital Structure as Adjusted to reflect NRLP's Actual Debt, Actual Capital Structure, and a Cost of Equity of 5% Bond Interest Rate plus 125 basis points for debt service coverage			
Capitalization Component	Ratio	Cost	Weighted Cost
Equity	78%	6.25%	4.89375%
Long-Term Debt	22%	2.3%	0.49910%
			5.39285%

II.A. NRLP's PROPOSED ROE, COST OF DEBT, ROR, AND CAPITAL STRUCTURE

Q. What are NRLP's current capital structure, allowed ROE, cost of debt, and allowed ROR?

A. NRLP's current capital structure is set out in NRLP witness Randall E. Halley's testimony,[3] as shown below:

Table JWH-2, NRLP Current Capital Structure

Capitalization Component	Ratio	Cost	Weighted Cost
Long-Term Debt	21.7%	2.30%	0.498%
Equity	78.3%	9.60%	7.517%
			8.015%

Q. What does NRLP propose for its capital structure, allowed ROE, cost of debt, and allowed ROR in this proceeding?

[3] Direct Testimony of Randall E. Halley on behalf of Appalachian State University d/b/a New River Light and Power at 30, Table 5 ("Halley Direct").

A. NRLP's proposed capital structure is set out in NRLP witness Halley's testimony,[4] as shown below:

Table JWH-3, NRLP Proposed Capital Structure

Capitalization Component	Ratio	Cost	Weighted Cost
Long-Term Debt	48%	4.20%	2.015%
Equity	52%	9.60%	4.992%
			7.007%

Q. What is the basis for NRLP's statement that it has a "cost of equity" of 9.60%?

A. NRLP is not capitalized with publicly traded equity, so it does not have an actual cost of equity. NRLP asserts that it has a cost of equity equal to its proposed return on equity, on the grounds that accounting rules treat retained earnings as equity capital.[5] However, this reasoning is circular.

Q. What is the basis for NRLP's statement that it has a cost of debt of 2.30%?

A. NRLP's current capital structure reflects its actual cost of debt.[6]

Q. What is the basis for NRLP's statement that its capital structure is based on a ratio of 78.3% equity to 21.7% debt?

A. NRLP relies primarily on retained earnings—excess margin or profits over costs and reserves—to fund capital projects. NRLP witness Halley asserts that the 78.3% / 21.7% ratio is the actual ratio reflecting NRLP's capital

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[4] *Id.* at 33, Table 6.
[5] *Id.* at 30:6-12.
[6] *Id.* at 30, table 5.

sources.[7] NRLP's actual equity to debt ratio has varied over the past ten years, with the equity fraction ranging between 77% and over 95%,[8] even while interest rates have generally been below 6% for the past twenty years.

Q. What is NRLP's basis for recommending a 9.60% ROE?

A. First, NRLP witness Halley cites[9] to the U.S. Supreme Court decision in *Federal Power Commission v. Hope Natural Gas*[10] for the proposition that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital."[11] Mr. Halley acknowledges that NRLP does not have publicly traded stock, but that NRLP's owner, ASU, must obtain capital to continue providing service.[12] Mr. Halley states that "NRLP should be allowed a weighted average cost of capital that includes a component at an appropriate risk-based cost of equity."[13] Mr. Halley states that the ROE should be set to prevent both diminishment of the retained earnings used to finance capital projects and a resulting increased reliance on debt such that NRLP's finances became "unbalanced."[14] Mr. Halley notes that two analytical methods are frequently

[7] *See* Halley Direct at 30.
[8] NRLP - Response to PS DR 1-7 - Attachment to E1-Response 33 a-d.
[9] Halley Direct at 24:4-16.
[10] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[11] *Id.* at 603.
[12] Halley Direct at 24:18-24.
[13] *Id.* at 25:2-3.
[14] *Id.* at 25:4-6.

used to ascertain a reasonable ROE—the DCF analysis, and the Comparable Earnings Analysis (CEA), but that he relied only on a CEA.[15] Mr. Halley did not perform or provide a DCF analysis in order to save an unspecified amount of time and money.[16]

Q. Please elaborate on NRLP's CEA.

A. NRLP proposes a 9.60% ROE based on a three-part CEA. In the first part, NRLP cites Commission-approved ROEs of 9.60% for two investor-owned gas distribution utilities, Piedmont Natural Gas, a business unit of Duke Energy,[17] and Public Service Company of North Carolina, a business unit of Dominion Energy.[18] NRLP's analysis effectively amounts to identifying these two companies as "distribution-only utilities."[19] In the second part of the CEA, NRLP provides fifteen years of rate case statistics from S&P Global Market Intelligence to show that authorized ROEs averaged 9.38% in 2021, and have been trending downward since 2009, but that NRLP "expect[s] the allowed ROEs to end their decline downward and to now move back upward."[20] In the third part, NRLP calculates average earned and expected ROEs for 34 investor-owned utility holding companies for the years 2020, 2021, 2022 (estimated), 2023 (estimated), and 2025 through

[15] *Id.* at 25:13-19.
[16] *Id.* at 25:21 – 26:5.
[17] *About Piedmont Natural Gas*, PIEDMONT NATURAL GAS, https://www.piedmontng.com/our-company/about-piedmont (last visited May 25, 2023).
[18] *Natural Gas Section*, PUBLIC STAFF—NORTH CAROLINA UTILITIES COMMISSION, https://publicstaff.nc.gov/public-staff-divisions/energy-division/natural-gas-section# (last visited May 25, 2023).
[19] Halley Direct at 26:12-16.
[20] *Id.* at 26:20 – 28:7.

2027 (estimated), based on Value Line's Investment Survey.[21] NRLP uses the results of these analyses to derive a range within which the proposed 9.60% ROE falls.[22]

Q. What is NRLP's basis for recommending its proposed capital structure?

A. NRLP recommends a capital structure of 52% equity and 48% debt, rather than its actual 78.3% equity and 21.7% debt capital structure, because the 52% / 48% equity ratio is comparable to that approved for the investor-owned gas distribution utilities that NRLP proposes as benchmarks.[23]

Q. What is NRLP's basis for recommending its proposed cost of debt?

A. NRLP witness Halley recommends using the average of the costs of debt for the two investor-owned gas distribution utilities that NRLP uses as benchmarks (4.37% and 4.02%), and not NRLP's actual embedded cost of debt of 2.30% because the cost of new debt that NRLP might secure (presumably through ASU) would be higher than the actual embedded cost.[24] NRLP also supports the use of a hypothetical cost of debt because it has recommended a hypothetical equity to debt ratio of 52% equity to 48% debt.[25]

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[21] *Id.* at 28:9 – 29:4.
[22] *Id.* at 29:6 – 30:4.
[23] *Id.* at 31:10-14.
[24] *Id.* at 31:16 – 32:2.
[25] *Id.* at 32:4-6.

II.B. NRLP's PROPOSED ROE, COST OF DEBT, ROR, AND CAPITAL STRUCTURE ARE UNREASONABLE AND DO NOT SUPPORT JUST AND REASONABLE RATES

Q. Does the *Hope* decision provide a good starting point for determining a reasonable return on capital investments made by a regulated utility in support of the provision of utility service?

A. Yes. In my experience, the comparable risk standard from the *Bluefield* and *Hope* decisions is where this analysis should start.[26] Reasonable and responsible utilities provide detailed analyses of comparable utilities, often set forth through the identification of a proxy group of utilities, to identify a range of reasonableness for proposed ROEs, RORs, and capital structures.

Q. What is your assessment of NRLP's proposed capital structure, allowed ROE, cost of debt, allowed ROR, and the basis for those proposals?

A. NRLP's proposals are unreasonable and will not support just and reasonable rates.

Q. What additional analysis should NRLP have conducted to support its proposed rate of return and capital structure?

A. NRLP should have conducted a DCF analysis because its CEA is inadequate and prone to bias. A DCF analysis is best practice for preparing a proposal for a rate of return. A DCF analysis requires the explanation of

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[26] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

a reasonable expectation and recovery of returns on investment, properly discounted by the cost of capital. A DCF analysis would properly include assumptions about the actual cost of capital for NRLP from the least-cost source, which would be ASU-issued bonds. It would also include a reasonable level of debt-service coverage that reflected any unique and different additional business risk that NRLP and ASU face. Lastly, the stream of payments necessary to meet debt service (and collect that coverage) would need to be discounted by the average cost of capital—university debt—that ASU experiences as the source of funds.

Q. What is your assessment of NRLP's basis for a proposed cost of equity of 9.60%?

A. The proposed 9.60% cost of equity in the proposed capital structure is not cost-based, is not appropriate under the accepted standards of utility rate making and will result in customers being required to pay excessive, unjust, and unreasonable rates. Indeed, NRLP uses its ROE *request* as its cost of equity.[27] NRLP does not pay anyone but itself and its owner at a "profit" rate of 9.60%. NRLP does not have publicly traded stock, nor does ASU. While accounting rules treat retained earnings as equity, this does not provide any relevant evidence to support Commission approval of an allowed ROE of 9.60% for a division of a state-operated, 501(c)(3) educational nonprofit institution. Moreover, there is no evidence from NRLP that the equity funds

[27] NRLP response to AV DR 7-7.

it uses for capital projects costs NRLP or ASU anything near 9.60%. In the absence of actual data relating to equity cost, NRLP should rely on an actual cost of capital in the form of prospective, long-term debt to establish a proxy value for equity cost and for use in a DCF analysis.

Q. What issues would NRLP encounter if it were allowed an ROE that was lower than 9.60% and based on its actual cost of capital?

A. None. NRLP could secure funding support from ASU through debt at a much lower cost to customers than 9.60%. In 2022, ASU issued $20 million in general revenue bonds to build a parking garage at a 4.06% interest rate,[28] and during the past 10 years, the bond rate for municipal bonds rated Baa or better has been under 5%.[29] On issuance of the $20 million in bonds, Moody's Investors Service assigned an Aa3 rating to ASU, noted that the University maintains a 13.6x coverage of fiscal 2023 proforma debt service,[30] and generally observed that the credit rating reflects ASU's "strong regional brand as a member of the University of North Carolina System with very good student demand and growing enrollment," and that ASU's credit quality is underpinned by strong operating and capital support from the State of North Carolina.[31] NRLP provides no evidence that funding

[28] NRLP Response to PS DR 13 Att. 11.

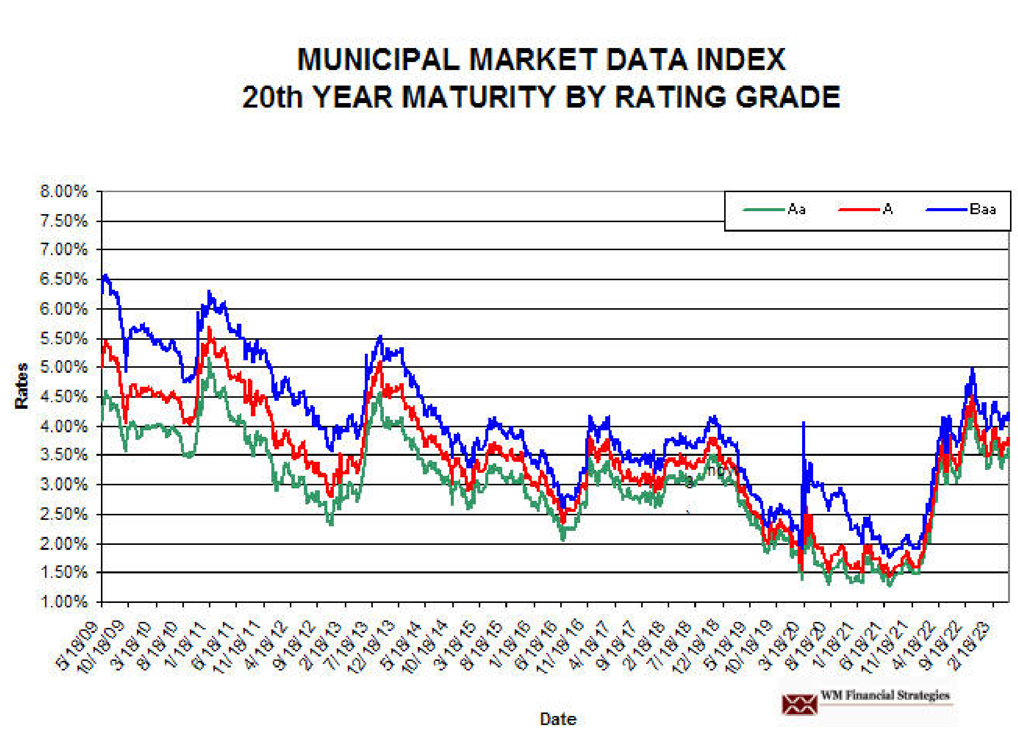
[29] *See, e.g.*, *Rates over Time – Interest Rate Trends*, WM FINANCIAL STRATEGIES, https://www.munibondadvisor.com/market.htm (last visited May 26, 2023).

[30] Refers to ratio of net operating income to annual debt service.

[31] Moody's, Board of Governors of the University of NC -- Moody's assigns Aa3 to Appalachian State University's (NC) general revenue bonds series 2022B; outlook stable, YAHOO (Aug. 17, 2022), https://www.yahoo.com/video/board-governors-university-nc-moodys-233106445.html.

capital projects with money that costs customers twice as much, or more, as debt is just or reasonable.

Figure JWH-1: Municipal Bond Interest Rates



Q. What evidence has NRLP provided that its capital needs could not be met with more debt and less dependence on retained earnings?

A. NRLP has provided no evidence that its capital needs could not be satisfied with lower-cost capital sourced from debt. NRLP has never had any problems raising capital.[32] NRLP's use of retained earnings with a hypothetical cost of equity generates excessive and unjust profits. NRLP

[32] NRLP response to AV DR 1-7.

could have saved customers substantial amounts of money by using a higher fraction of debt funding, and by using borrowed money to pay for capital projects. That is because NRLP is an operating division of a public university and has access to low-cost capital through low-risk sources, including public financing options. In addition, ASU maintaining and operating NRLP, which also has non-ASU customers, reduces the business operating risk ASU faces in managing its university operations. Finally, as a public university, ASU can apply and compete for substantial funding support from the federal government under the Inflation Reduction Act. According to NRLP, "[ASU] and NRLP have and continue to pursue numerous programs related to energy conservation, weatherization, energy storage, alternative energy, and demand side management," are pursuing IRA funding for three new renewable energy systems and other renewable energy projects, are writing IRA-related grant applications, and are pursuing IRA section 6417 "Direct Pay" elections or tax credits, among other efforts.[33] These are risk- and cost-reduction opportunities that the gas utilities that NRLP chose as benchmarks do not enjoy.

Q. How does a higher-than-reasonable allowed ROE impact NRLP's customers?

A. According to NRLP, each added basis point (1/100th of a percentage point) of ROE adds $1,832 to the total revenue requirement when calculated using

[33] NRLP responses to AV DR 7-11 through 7-13, 7-15, 7-16, 7-17 through 7-20.

NRLP's proposed capital structure of 52% equity and 48% debt.[34] My analysis shows that an ROE of 9.60% is about 335 basis points higher than reasonable, meaning that NRLP's proposed revenue requirement under its proposed capital structure is about $613,600 higher than it should be as a result of its higher-than-reasonable proposed ROE.[35]

Q. How does excessive reliance on retained earnings for financing capital projects impact NRLP's customers?

A. Each additional percentage point added to the equity portion of the capital structure (and subtracted from the debt portion) increases the total revenue requirement by $16,485, at NRLP's proposed ROE of 9.6% and proposed cost of debt of 4.2%. Given that NRLP's current actual equity fraction of 78.3% is 26.3% higher than its proposed 52% equity fraction, NRLP customers would pay $433,550 more than they would if the Commission approved a 52% equity fraction,[36] a fraction that even NRLP finds more reasonable than its "too high and unfair" actual capital structure.[37] I propose that the Commission order NRLP to develop a comprehensive financing strategy that optimizes the capital structure for the utility in light of its status as an operating unit of ASU.

[34] NRLP response to AV DR 1-4.
[35] Calculated as (9.60% - 6.25%) = 335 basis points. $1,832 per basis point x 335 basis points = $613,600. This calculation was performed using my recommendations from this testimony and NRLP response to AV data request 1-4.
[36] Calculated as (78.3% - 52.0%) = 2,630 basis points. 2,630 bp x $165 = $433,950.
[37] Halley Direct at 30:15-17.

Q. Do you have other concerns regarding NRLP's excessive reliance on retained earnings and higher-than-reasonable allowed ROE?

A. Yes. The combination of NRLP's limited capital needs, its excessive reliance on retained earnings, and higher-than-reasonable allowed ROE have previously allowed NRLP to charge rates that included excessive returns during the period of about 20 years between general rate case filings. Between 1996 (Docket No. E-34, Sub 32) and 2017 (Docket No. E-34 Sub 46), NRLP did not file a general rate case and instead relied on the 10.65% ROR and capital structure of 6.42% debt and 93.58% equity, with a cost rate of 5.62% for debt and 11.0% for common equity during those decades. Recommended Order Granting Increase in Rates at 9, ¶ 38, *In the Matter of Application by New River Light and Power Company for Authority to Adjust and Increase its Electric Rates and Charges*, Docket No. E-34, Sub 32 (N.C.U.C. May 1, 1997). The cost rate for debt and equity were significantly lower than those approved for NRLP during most of that period, which resulted in both an "earnings windfall" for NRLP as its rates of return were well-above competitive market rates and subjected NRLP customers to unjust and unreasonable rates. NRLP's excessive reliance on retained earnings and higher-than-reasonable allowed ROE presents significant risks of unjust and unreasonable rates not just in the immediate future but potentially for decades to come if NRLP elects not to file a general rate case.

Q. How does NRLP's proposal to fund capital projects with retained earnings, an excessive equity fraction, a hypothetical 9.60% return on equity, and 4.20% cost of debt impact ASU in particular?

A. More than 20% of NRLP's electricity sales in 2022 were to ASU.[38] While ASU reduces its business operating risks by owning and managing its own electric distribution utility, a considerable share of operating costs, about $16 million, was paid to NRLP.[39] NRLP charges ASU the same excessive rate of return that it does other customers it serves.[40] NRLP also receives substantial support from ASU in terms of information technology, human resources, and legal counsel services.[41] Under North Carolina law, NRLP's net profits are to be transferred to the ASU Endowment Fund, and to benefit the university.[42] By overcharging for the cost of equity and the cost of debt, and by over-relying on equity for financing capital projects, NRLP proposes to reduce funds available for transfer to the ASU Endowment Fund as net profits, to overcharge ASU for electric service and increase the tax burden for all citizens of North Carolina, to increase the costs and fees for students, and to increase the costs for businesses and services in the ASU area.

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[38] NRLP response to AV DR 4-1 att.
[39] Office of the State Auditor, Beth A. Wood, CPA, ASU Financial Statement Audit Report for the Year Ended June 30, 2022, 12, Chart 2.1, https://controller.appstate.edu/sites/default/files/2022.pdf.
[40] NRLP response to AV DR 4-9.
[41] NRLP response to AV DR 4-3.
[42] N.C.G.S. § 116-35.

Q. What is your assessment of NRLP's approach to developing its recommendation for a 9.60% ROE?

A. NRLP's ROE proposal is fundamentally flawed because NRLP has failed to present substantial and persuasive evidence that supports the proposal. There are several flaws with its proposal, which are addressed below.

Q. What is your assessment of NRLP's failure to perform a DCF analysis?

A. NRLP's failure to perform a DCF analysis is unreasonable, especially when considered alongside NRLP's deficient CEA. NRLP's failure to perform a DCF analysis leaves the Commission with only the subjective, incomplete, and unreasonable proposal of NRLP witness Halley.[43]

Q. What is your assessment of NRLP's selection of two gas distribution utilities as benchmarks for setting the proposed ROE, cost of debt, and equity ratio?

A. NRLP's choice of two investor-owned gas distribution utilities for benchmarking its ROE proposal—Part 1 of its CEA—violates the principle that NRLP's allowed ROE should be based on indicators from utilities with comparable risk. NRLP's witness Halley states that the two investor-owned gas utilities were identified as benchmarks solely because they are also distribution-only utilities,[44] however there is language in his testimony that would seem to suggest that this equity fraction was used in part because of the sizeable costs customers would bear if NRLP's actual equity fraction

[43] NRLP response to AV DR 4-10.
[44] NRLP responses to AV DR 4-11, 4-12.

were applied.[45] Even so, NRLP's analysis overlooks important differences between the distribution gas utilities and NRLP. For example, it ignores the fact that industry and consumer trends away from reliance on fossil fuels increase risk for gas utilities but reduce risk for electric utilities. If gas customers stop using gas, the gas utility goes out of business, and electric utilities will gain heating market share. NRLP is exploring and developing supply alternatives that mitigate risks associated with the transition away from fossil fuel use. NRLP has offered no information to support its assertion that the capital spending plans for the gas utilities are comparable to those of NRLP. NRLP overlooks the fact that the gas utilities are investor-owned and not an operating division of a state-funded university with a significantly lower cost of capital. NRLP overlooks the fact that a substantial fraction of NRLP's load is essentially captive—the university and student body.[46] Mr. Halley overlooks the fact that the Boone, North Carolina community has a strong vacation and skiing economy that peaks during times when the University is closed or experiencing reduced enrollment, so non-university load complements ASU load. NRLP also fails to account for the fact that ASU receives substantial support from ASU for information technology, human resources, and legal services, all of which would cost NRLP more outside the University system.[47]

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[45] *See* Halley Direct at 30:13-17.
[46] NRLP response to AV DR 4-1 att.
[47] NRLP response to AV DR 4-3.

Q. In sum, does NRLP face comparable business risk to that of the two investor-owned gas utilities that it proposes as benchmarks for setting NRLP's allowed ROE?

A. No. As illustrated by all the important differences I just discussed, simply being a distribution-only utility is not sufficient to make the gas utilities comparable to NRLP for purposes of setting its ROE.

Q. What is your assessment of NRLP's reliance on S&P Global Market Intelligence data?

A. NRLP's reliance on investor-owned utility data from S&P Global Market Intelligence—Part 2 of its CEA—also violates the principle that allowed ROE should be benchmarked against utilities with comparable risk. NRLP made no showing that the utilities in the S&P data set are comparable to NRLP. NRLP does not distinguish or otherwise characterize this data set in any useful fashion. The S&P data is not a reasonable basis for NRLP's ROE proposal.

Q. What is your assessment of NRLP's proposal to deviate from the S&P data for 2021?

A. NRLP's proposal to add 22 basis points to the most recent 2021 average ROE in the S&P dataset based on witness Halley's expectation[48] is unjustified. The proposal is not calibrated in any fashion and therefore provides no reasonable basis of support for NRLP's proposal. In response

[48] NRLP "expect[s] the allowed ROEs to end their decline downward and to now move back upward." Halley Direct at 26:20 – 28:7.

to a request for additional information, NRLP cites rising interest rates and the allowed rate of return for a water utility as justification for an increased ROE for NRLP, but again fails to address how NRLP's business and financial conditions justify comparable increases.[49]

Q. What is your assessment of NRLP's reliance on Value Line Investment Survey data?

A. NRLP's reliance on investor-owned utility data from Value Line Investment Survey data—Part 3 of its CEA—violates the principle that allowed ROE should be benchmarked against utilities with comparable risk. The utilities included in the Value Line data are utility holding companies with publicly traded stock, multi-state operations, generation assets, and diverse regulatory climates. Many have major capital requirements for infrastructure needs, generation needs, grid modernization requirements, performance-based regulation standards, and other activities. NRLP does not distinguish or otherwise characterize this data set in any useful fashion. NRLP offers the Value Line numbers while acknowledging that a fuller analysis that is based on more recent data or provides adjustments for comparable risk is beyond the evidence produced by NRLP.[50] The Value Line data is not a reasonable basis for NRLP's ROE proposal.

[49] NRLP response to AV DR 4-13.
[50] NRLP response to AV DR 4-14.

Q. What is your assessment of NRLP's proposal to use a hypothetical cost of debt in its proposed capital structure?

A. NRLP's cost of debt proposal is unreasonable. In making his recommendation, Mr. Halley relies on a simple arithmetic averaging of the approved costs of debt for the two gas distribution utilities chosen as benchmarks for his ROE proposal. As previously explained, Mr. Halley's basis for benchmarking his proposal against those two gas distribution utilities is not reasonably developed as it relies only on the unquantified assertion that NRLP and the two gas utilities are of similar size and are all distribution-only utilities. The cost of debt should not be set based on the financial characteristics of utilities with a wholly different capital structure. NRLP has actual cost of debt data supporting a 2.30% rate and should use it.

Q. What is your assessment of NRLP's proposal to use a 52% / 48% equity to debt ratio?

A. First, it is important to be clear that NRLP is not planning to finance capital projects according to a 52% / 48% equity to debt ratio.[51] Second, as explained by Mr. Halley, NRLP is proposing that the Commission approve a hypothetical equity to debt ratio for purposes of establishing the weighted average cost of capital that NRLP will use as a profit level in developing its rates. The lower equity fraction (proposed 52% equity fraction in

[51] Halley Direct at 30:6-10.

comparison to the actual 78.3% equity fraction) that NRLP proposes is necessitated by the fact that NRLP proposes an excessive and unjustified ROE—if the actual equity to debt ratio is used with such a high ROE, the resulting rates would be even more unfair. NRLP fully acknowledges that it is asking the Commission to base actual rates on these hypothetical financial constructions.[52] A 52% equity and 48% debt capital structure does not represent NRLP's actual capital structure, and to the extent that NRLP is recommending this hypothetical capital structure, it is because of NRLP's acknowledgment that approval of its real, current capital structure, when coupled with its proposed ROE of 9.6%, would result in significantly high customer costs that would not otherwise be justified by or required under *Hope* and *Bluefield*.[53] While this Commission has approved the use of hypothetical capital structures as a means of containing customer costs, among other things, use of a hypothetical capital structure here, specifically for a utility that has no shareholders and has ready access to low-risk capital, in particular public financing, would not be appropriate. Use of a lower ROE and NRLP's real capital structure would reflect the current financial conditions NRLP experiences and would result in compensation that is consistent *with Hope* and *Bluefield.* The fact that Mr. Halley asserts that the proposed ratio is comparable to those approved for the two gas distribution utilities he used as benchmarks does not redeem the proposal.

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[52] NRLP responses to AV DR 4-15, 4-16.
[53] *See* Halley Direct at 30:13-17.

Again, there is not sufficient evidence that the business and financial conditions for those gas distribution utilities are in any meaningful way comparable to those under which NRLP operates.

Q. Please summarize your assessment of NRLP's proposed ROE, cost of debt, ROR, and capital structure.

A. NRLP has not met its burden of submitting credible evidence to support its proposals. NRLP's proposals are unreasonable and will not result in rates that are just and reasonable for its customers. The Commission should reject NRLP's proposals.

II.C. RECOMMENDATIONS FOR NRLP's ROE, COST OF DEBT, ROR, AND CAPITAL STRUCTURE

Q. Do you have recommendations for the Commission regarding NRLP's ROE, cost of debt, ROR, and capital structure that will support just and reasonable rates for electric service?

A. Yes. First, the Commission should direct NRLP to move to actual, cost-based values as a basis for ROE, cost of debt, ROR, and capital structure in this case and in future cases. Second, the Commission should direct NRLP to develop a DCF analysis and develop a comprehensive financing strategy that optimizes the capital structure for the utility in light of its status as an operating unit of ASU. Third, the Commission should direct NRLP to submit a compliance filing for its ROR, based on its DCF analysis.

Q. What is your recommendation for the ROE that the Commission should approve for NRLP?

A. The Commission should approve an ROE that reflects the actual cost of obtaining capital that NRLP faces. As an operating unit of ASU, and as a utility that is not financed with traded equity, it is appropriate to look at the cost of capital ASU must pay. As previously stated, ASU has obtained some $20 million in funds through the issuance of bonds at an interest rate of 4.06%. As recent municipal bond data shows, municipal bond interest rates have recently been as high as 5%. As a conservative approach, I recommend using the 5% value as a starting point in setting the approved ROE for NRLP. However, I note that it is also reasonable to assume that NRLP's earnings should be enough to cover the cost of capital even if revenues experience some level of volatility. Therefore, I recommend that the starting point for the allowed ROE be increased by an additional 1.25% to reflect that the rate for bonds would also be adjusted to account for debt service coverage. This coverage level is identified as reasonable by Moody's Investors Service in its U.S. Municipal Utility Revenue Debt Methodology.[54] As a result, I find that an allowed ROE of 6.25% would be

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[54] MOODY'S INVESTORS SERVICE, U.S. MUNICIPAL UTILITY REVENUE DEBT METHODOLOGY 8-9 (2022), https://ratings.moodys.com/api/rmc-documents/386721#:~:text=We%20measure%20or%20estimate%20utilities,are%20sufficient%20to%20meet%20expenditures.&text=Debt%20service%20coverage%20is%20a,of%20a%20utility%20revenue%20system.

reasonable and I recommend that the Commission approve 6.25% as an ROE for use in setting NRLP's weighted average cost of capital.

Q. What cost of debt do you recommend that the Commission approve for use in setting the approved capital structure for NRLP?

A. In keeping with the principle that just and reasonable rates should be based on cost of service, I recommend that the Commission authorize NRLP to use its historical embedded cost of debt of 2.30% in its capital structure and for use in developing its weighted average cost of capital.

Q. What equity to debt ratio should the Commission approve for NRLP?

A. North Carolina law contemplates that NRLP's net "profits" will be transferred to the Endowment Fund, so an imputed cost of equity approach is appropriate and can be reasonably implemented. NRLP's equity fraction results in rates that NRLP acknowledges would be "too high and unfair."[55] To the extent that the cost of equity can be expected to continue to significantly exceed the cost of long-term debt, an appropriate equity to debt ratio should be the result of a more comprehensive analysis than provided in this proceeding. As acknowledged by NRLP, a good starting point would be a 50% equity and 50% debt ratio.[56] Again, for purposes of setting rates in this proceeding, I recommend that the Commission approve the 78.3% equity / 21.7% long-term debt capital structure based on NRLP's actual cost of service. I further recommend that the Commission direct NRLP to

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[55] Halley Direct at 30:15-17.
[56] Halley Direct at 31:5-7.

develop a DCF analysis and develop a comprehensive financing strategy that optimizes the capital structure for the utility in light of its status as an operating unit of ASU. I anticipate that this effort will result in a more balanced and equitable capital structure for NRLP. To ensure a timely correction, the Commission should direct NRLP to conclude this effort within a reasonable time frame, such as within one year after the final order in this case is entered and submit a report to the Commission and incorporate any proposals in its next application to change rates.

Q. Based on your analysis, what do you propose as a reasonable ROR for NRLP?

A. I recommend an ROR of 5.39% for NRLP.

Table JWH-5: Proposed ROR for NRLP

Capital Structure as Adjusted to reflect NRLP's Actual Debt, Actual Capital Structure, and a Cost of Equity of 5% Bond Interest Rate plus 125 basis points for debt service coverage			
Capitalization Component	Ratio	Cost	Weighted Cost
Equity	78%	6.25%	4.89375%
Long-Term Debt	22%	2.3%	0.49910%
			5.39285%

Q. What would the general benefit of these adjustments be?

A. There are several benefits that would accrue from implementation of my recommendations regarding NRLP's capital structure and rate of return:

- NRLP's costs would be better aligned with the true cost of service, especially NRLP's actual cost of capital.
- NRLP would have a strong incentive to optimize its capital structure to take advantage of the lower cost of capital it can obtain through ASU and the North Carolina University System.
- NRLP's non-university residential customers would have reduced rates and bills that more accurately reflected the actual cost of service. These customers would no longer be forced to pay excessive rates solely to fund NRLP's excessive costs and the ASU Endowment Fund.
- NRLP's non-university business customers would also see rate and bill reductions and would be more economically competitive—as the rate and bill reductions would in turn reduce business costs, increase business profits, and grow the regional economy.
- ASU's costs to maintain and operate the university would be reduced, also reducing costs to North Carolina taxpayers in general.

Q. Have you estimated the impact of your recommendations on NRLP's revenue requirement?

A. Yes. The changes that I propose to NRLP's capital structure, cost of debt, and ROE would result in NRLP's capital structure reflecting the actual cost of service and would reduce the revenue requirement by a total of $492,711 systemwide, by $151,983 for the residential class, and by $61,427 for small commercial customers, compared to NRLP's proposal.

III. Establishment of EE and DSM Programs for NRLP Customers

Q. Is NRLP required to develop proposals for EE and DSM programs?

A. Yes. In NRLP's last rate case before the NCUC, NRLP agreed in a stipulation with the Public Staff – North Carolina Utilities Commission (Public Staff) to work to develop rate schedules and EE and DSM programs that take advantage of the detailed usage data and other capabilities of its AMI metering system. Stipulation of New River and Public Staff, ¶ 38, *In the Matter of Application of Appalachian State University, d/b/a New River Light and Power Company, for an Adjustment of Rates and Charges for Electric Service in North Carolina*, Docket No. E-34, Sub 46 (N.C.U.C. Jan. 19, 2018). The Commission accepted the stipulation, including NRLP's agreement to develop these rate schedules and programs, recognizing that NRLP would be unable to implement EE or DSM programs until its contract with BREMCO ended, and to report on its progress to the Public Staff within 180 days. Order Accepting Stipulation and Granting Increase in Rates, FOF ¶ 41, *In the Matter of Application of Appalachian State University, d/b/a New River Light and Power Company, for an Adjustment of Rates and Charges for Electric Service in North Carolina*, Docket No. E-34, Sub 46 (N.C.U.C. Mar. 29, 2018).

Q. Has NRLP developed any EE/DSM programs since its last rate case?

A. According to NRLP Response to AV Request 6-13 (a), NRLP has not submitted any DSM programs to the NCUC in this rate case or as part of other proceedings before the Commission. According to NRLP Response to AV Request 6-13 (e), NRLP indicated it is pursuing grant opportunities related to the following possible EE/DSM programs:

1) Heat Pump and Water Heater Rebate programs;
2) EV charging infrastructure throughout NRLP territory;
3) Installation of programable thermostats that may be controlled by NRLP at a customer's request.

Q. Do other retail electric providers in North Carolina and elsewhere offer similar EE/DSM programs to those NRLP has identified?

A. Yes, a brief list of some example EE/DSM programs that are similar to those NRLP has identified is provided in Exhibit JWH-2.

Q. Do NRLP's wholesale power supply-related contract(s) prohibit or restrict its ability to offer DSM programs to its customers?

A. According to NRLP Response to AV Request 6-13 (b) and (c), the Wholesale Distribution Services Agreement, dated August 2, 2021, between NRLP and Blue Ridge Electric Membership Corporation (BREMCO) does not prevent the development of energy efficiency and demand side management programs by NRLP. According to NRLP Response to AV Request 6-13 (b), pursuant to the new agreement, NRLP has been able to offer energy efficiency and DSM programs to its customers since January 2022, and has been aware that it can since at least August 2, 2021, when the new agreement was executed.

Q. What, if any, programs did NRLP develop instead of EE/DSM programs since its last rate case?

A. According to NRLP Response to AV Request 6-13 (b), NRLP chose to offer its customers subscriptions to the NC Green Power Program instead of EE/ DSM programs.

Q. Is offering customers the option of participating in the NC Green Power Program equivalent to or a replacement for EE/ DSM programs?

A. No, offering customers the option to increase the carbon-free or renewably generated portion of their individual power supply through the NC Green Power Program does not assist or support customer efforts to reduce energy consumption or load. Energy efficiency and DSM programs target changes in customer demand and energy use, while green power programs focus on the source and characteristics of power supply.

Q. What reason(s) did NRLP offer as justification for not developing any EE/DSM programs since its last rate case?

A. In response to AV Request 6-13 (b), NRLP referenced customer interest in renewable energy indicated by the results of a 2020 customer survey, and its choice "to pursue the Green Power Program that all customers could participate [in] regardless of being home owners or renters" as justification for why no EE/ DSM programs have been proposed since its last rate case.

Q. How does NRLP's mix of residential customers, including the proportions of homeowners and renters, compare to that of North Carolina?

A. Using the Town of Boone, North Carolina as a proxy for NRLP's service area, recent data[57] from the United States Census Bureau show that owner-occupied housing units account for only 23.4% of total housing units in the NRLP service area, while owner-occupied housing units represent 65.9% of total housing units in North Carolina statewide. According to a recent study conducted for the Town of Boone, the number of renter-occupied housing units in NRLP's service territory is also growing rapidly. Between 2009 and 2019, the number of housing units increased by nearly 20% from less than 5,700 to about 6,800.[58]

Residential mobility in the NRLP service area is also much higher than that of the state at large, with only 46.7% of people living in the same residence as the previous year in NRLP's service territory compared to 85.9% of people statewide who lived in the same residence as of one year

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[57] *QuickFacts Boone town, North Carolina*, UNITED STATES CENSUS BUREAU, https://www.census.gov/quickfacts/boonetownnorthcarolina (last visited June 6, 2023); *QuickFacts North Carolina; United States*, UNITED STATES CENSUS BUREAU, https://www.census.gov/quickfacts/fact/table/NC,US/PST045222 (last visited June 6, 2023).

[58] EVE LETTAU AND JESSICA WILKINSON, HOUSING AND BUSINESS RESILIENCY IN BOONE, NORTH CAROLINA, NC GROWTH, NOVEMBER 2021, http://www.townofboone.net/DocumentCenter/View/1336/Housing-and-Business-Resiliency-in-Boone-NC-November-2021-PDF (REPORT ON HOUSING AND BUSINESS RESILIENCY IN BOONE).

ago.[59] Annual per capita income and median household income in the NRLP service area are about 41% of the statewide averages.[60]

Overall, residential customers in NRLP's service area have significantly less income than statewide average levels, occupy rental housing units at 2.8 times the rate of rentals statewide, and tend to change residences from one year to the next at 1.8 times the statewide average rate. These differences in residential characteristics reflect the large share of college and university students living in NRLP's service territory. Annual student enrollment at ASU is over 20,000 students[61] while the Town of Boone's latest population estimate[62] from July 1, 2022 is 19,756.

Q. Do these differences in residential customer characteristics reduce the importance of NRLP developing energy efficiency or DSM programs?

A. No, in fact, the comparatively high proportion of NRLP customers who are renters and who have incomes well below state average income levels mean that energy efficiency and DSM programs would likely have even greater beneficial impacts on electricity customers in NRLP's service

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[59] *QuickFacts Boone town, North Carolina*, UNITED STATES CENSUS BUREAU, https://www.census.gov/quickfacts/boonetownnorthcarolina (last visited June 6, 2023); *QuickFacts North Carolina; United States*, UNITED STATES CENSUS BUREAU, https://www.census.gov/quickfacts/fact/table/NC,US/PST045222 (last visited June 6, 2023).
[60] *Id*.
[61] *Institution(s): All, Enrollment Measure: Student Count*, UNIVERSITY OF NORTH CAROLINA, https://myinsight.northcarolina.edu/t/Public/views/db_enroll/EnrollmentbyLevel?iid=1&%3AisGuestR%20edirectFromVizportal=y&%3Aembed=y (last visited June 6, 2023).
[62] *QuickFacts Boone town, North Carolina*, UNITED STATES CENSUS BUREAU, https://www.census.gov/quickfacts/boonetownnorthcarolina (last visited June 6, 2023).

territory than in other parts of the state. Energy efficiency and DSM programs benefit customers by reducing energy costs, reducing the energy burden on household finances, improving health and comfort, reducing greenhouse gasses and other air emissions, and increasing the resiliency of NRLP's electric service. Energy efficiency and DSM programs offer the potential for NRLP to reduce costs for all customers by reducing peak loads and overall energy consumption.

Q. What are some implications of the unique characteristics of residential customers in the NRLP service area for EE/DSM programs?

A. Residential customer characteristics in the NRLP service territory have several implications for the design and implementation of EE/ DSM programs.

First, about 75% of housing units in the NRLP service area are rental housing units, most of which are occupied by ASU students.[63] The NRLP service territory is somewhat unique in that the share of *renter*-occupied housing units is actually 10% higher than the statewide average share of *owner*-occupied housing, so any NRLP EE/DSM programs targeting renter-occupied housing would be available to a larger share of all residential customers in NRLP service territory than most EE/DSM programs targeting single-family housing in other utility territories.

[63] REPORT ON HOUSING AND BUSINESS RESILIENCY IN BOONE.

Second, the nature of renter-occupied multi-family housing further enhances opportunities to leverage economies of scale because multiple housing units of this type are typically owned or controlled by a single owner/entity; multiple housing units of this type are part of the same building structure and are typically built at the same time using the same methods and materials; and any physical modifications to the building structure, envelope, fixtures, or appliances could be undertaken in a large or bulk-type contract rather than on a one-off basis. For purposes of EE/DSM program planning, benchmarking[64] is a method of evaluating and comparing the energy use of a building to other buildings to gain insight into the market potential of EE/DSM programs. Using benchmarking techniques to develop and evaluate potential EE/DSM programs would enable NRLP to identify, prioritize, and pursue EE/DSM opportunities appropriate to the mix of residential housing units in its service territory.

Third, the large number of NRLP customers and electricity consumers affiliated with ASU combined with the ability to reach these consumers with relative ease by using existing university-based communication channels suggests that energy consumption/peak load reductions from the use of behavior-based EE/DSM programs are more

[64] Benchmarking entails assessing a building's energy usage over time and comparing that building's energy usage with its peers. ANDREW SCHULTE ET AL., AMERICAN COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY (ACEEE), LEVERAGING DSM PROGRAMS TO DELIVER ON THE PROMISE OF BENCHMARKING AND DISCLOSURE POLICIES 7-1 (2016), https://www.aceee.org/files/proceedings/2016/data/papers/7_151.pdf.

feasible for NRLP than other electric utilities because such a high share of electricity consumers in NRLP's service territory are connected to the same community asset (i.e., ASU). Such behavior-based programs are made possible by a combination of AMI deployment and the utility's ease of access to a large number of consumers and could capitalize on existing common networks within the community to inform not just NRLP customers but also the much-larger population of electricity consumers active within its territory to provide information about peak load conditions/forecasts and actions electricity consumers could take to reduce peak load.

Fourth, the high share of renters and high levels of residential mobility within the NRLP service territory indicates a large portion of NRLP residential customers routinely change residences. This characteristic exacerbates common challenges to the design of EE/DSM programs, including but not limited to, the issue of split incentives and the potential for stranded EE/DSM program assets.

Split incentives occur when the person making the investment is not the same person who primarily benefits from the investment, such as the case between a property owner who would invest in higher efficiency appliances or building envelope upgrades (i.e., more efficient windows, insulation, etc.) and rental tenants who benefit from these improvements through reduced electricity bills. Generally, approaches to mitigating the challenge of split incentives and the resulting reduced participation in

EE/DSM programs involve methods that share the costs or benefits, effectively “unsplitting” the incentives to the extent possible, or highlighting other sources of benefits that, while valuable, may not be as obvious as energy cost savings. A highly mobile customer base means that tenants are routinely seeking and making comparisons among potential new residences. EE/DSM programs that provided a means for property owners to enhance the marketing and potentially the monthly rental fee of properties based on tenant energy savings and improved comfort, etc. would be one option for “unsplitting” incentives in an area with a highly mobile residential population.

Another implication related to high residential mobility is the risk that devices or equipment provided by the utility enabling participation in an EE/DSM program may become a stranded investment if the next tenant/NRLP customer who occupies the residential unit declined to participate. This risk can be mitigated through aspects of program design, such as using an incentivized EE/DSM default rate or rate rider for accounts located in residential units where programmable thermostats have been installed, working with property owners/managers to require participation in the programmable thermostat program as part of the lease agreement, and incorporating this option as part of a rental property marketing.

Q. What is your opinion of the possible EE/DSM programs for which NRLP has indicated it is pursuing grant opportunities?

A. NRLP indicated it is pursuing grant opportunities related to the following possible EE/DSM programs: 1) heat pump and water heater rebate programs; 2) EV charging infrastructure throughout NRLP territory; and 3) installation of programable thermostats that may be controlled by NRLP at a customer's request. In general, EE/DSM programs of the type NRLP listed can be effective at reducing energy consumption and peak load, and I am supportive of the general concept of these types of EE/DSM programs. However, without additional details on program design; incentive levels; expected savings; expected program costs; program evaluation, measurement, and verification (EM&V) plans; and the participation potential of NRLP's residential customers, etc., I am not able to evaluate the possible EE/DSM programs NRLP has listed and reach a firm conclusion regarding any specific programs.

Q. What additional EE/DSM program planning by NRLP do you think is necessary and why?

A. To begin with, I am appreciative and supportive of NRLP's efforts to pursue grant opportunities in the development of some possible EE/DSM programs, particularly considering that NRLP is a small utility with little experience in this area because of its previous wholesale supply contracts which effectively prevented the development of these types of programs.

Planning is an important and necessary step in the development of EE/DSM programs. A basic EE/DSM program plan that does the following would provide valuable information:

- Establishes the overall goals for a utility's EE/DSM efforts;
- Sets forth guiding principles for the utility's portfolio of EE/DSM programs (e.g., low-income assistance targets, share of programs focused on single-family or multi-family residential units, the role of stakeholders like customers, property owners, installers, other EE program providers in program development and design);
- Characterizes and benchmarks the residential sector in the utility's territory based on pertinent building attributes (e.g., residential units with electric heating, residential units with HVAC systems, residential units constructed before recent energy efficiency additions to building codes);
- Evaluates a variety of EE/DSM program options to compare potential participation rates, potential energy savings, expected program costs, etc.;
- Defines the EM&V process and program review standards; and
- Provides a timeline with specific milestones for program design, development, review, and modifications.

A foundational plan such as this would allow comparisons between EE/DSM program options, provide information about the scope and reach of EE/DSM programs, allow specific program options to be considered in the context of both NRLP's customer base and the full portfolio of NRLP's program offerings, and serve as a reference to guide the ongoing process of EE/DSM portfolio and program design, development, implementation, and evaluation.

Q. What are your recommendations regarding NRLP's development and implementation of EE/ DSM programs?

A. My recommendations are as follows:

1) NRLP should formally propose the three EE/DSM programs it has already identified and listed, guided by the program designs discussed in Exhibit JWH-2, as pilot programs of limited duration.

2) NRLP should prepare and file an EE/DSM plan that addresses the topics identified herein and that specifically includes a market evaluation, an evaluation of multiple EE/DSM program options, an EM&V plan (that would apply to the pilot programs at a minimum, and ideally to other future programs as well), and a clear timeline with milestones for program development. NRLP should develop the EE/DSM plan concurrently with the pilot EE/DSM offerings discussed above and use the plan and the results of the pilots to develop permanent offerings at the end of the pilot period.

3) As a complement to the three programs discussed above, NRLP should develop a behavior-based DSM program that allows NRLP to communicate with customers as a means of reducing NRLP load during times of grid stress and during coincident peak hours. The communications could,

among other things, inform customers about the three programs discussed above. For maximum effect, given the high proportion of students in NRLP's service territory, the program should be available to all electricity consumers in NRLP's service territory and not restricted exclusively to NRLP customers. NRLP should develop this as a pilot program as well and evaluate its effectiveness along with the other three pilot programs at the end of the pilot period.

4) NRLP should consider adding a program focused on weatherization and building retrofits/upgrades, particularly for older less-energy efficient residential units.

IV. Concluding Remarks and Summarized Recommendations

Q. Please summarize your recommendations to the Commission regarding NRLP's proposals relating to ROR, ROE, cost of equity, cost of long-term debt, and capital structure.

A. In summary, NRLP is a division of a state-operated non-profit educational institution and its allowed ROE and ROR should reflect this fact. As NRLP has acknowledged, its actual capital structure is overweighted towards equity, but NRLP's proposal to adopt a hypothetical capital structure that more closely resembles a capital structure typical of a publicly traded utility does not alter the fundamental differences between NRLP as a division of a state-operated non-profit educational institution and a utility with publicly traded equity and does not justify a comparable ROE to that of a utility with publicly traded equity. My proposal is based on NRLP's actual capital structure, recommends NRLP develop a DCF analysis and a comprehensive financing strategy to optimize its capital structure, recommends use of NRLP's actual cost of debt, and recommends an ROE that reflects NRLP's actual cost of obtaining new capital plus a premium based on debt service coverage.

My recommendations are as follows:

- The Commission should direct NRLP to move to actual, cost-based values as a basis for ROE, cost of debt, ROR, and capital structure in this case and in future cases.
- The Commission should direct NRLP to develop a DCF analysis and develop a comprehensive financing strategy that optimizes the capital structure for the utility considering its status as an operating unit of ASU.
- The Commission should direct NRLP to submit a compliance filing following the completion of its DCF analysis that reflects recalculated ROR and capital structure.
- The Commission should approve an ROE that reflects the actual cost of obtaining capital that NRLP faces. I recommend using the 5% value as a starting point in setting the approved ROE for NRLP and that the starting point for the allowed ROE be increased by an additional 1.25%

to reflect that the rate for bonds would also be adjusted to account for debt service coverage. Accordingly, I recommend that the Commission approve 6.25% as an ROE for use in setting NRLP's weighted average cost of capital.

- I recommend that the Commission authorize NRLP to use its historical embedded cost of debt of 2.30% in its capital structure and for use in developing its weighted average cost of capital.
- I recommend that the Commission approve the 78.3% equity / 21.7% long-term debt capital structure based on NRLP's actual cost of service.
- I recommend an ROR of 5.39% for NRLP.

Q. Please summarize your recommendations to the Commission regarding the establishment of EE/DSM programs by NRLP.

A. My recommendations are as follows:

- NRLP should formally propose the three EE/DSM programs it has already identified and listed, guided by the program designs discussed in Exhibit JWH-2, as pilot programs of limited duration.
- NRLP should prepare and file an EE/DSM plan that addresses the topics identified herein and that specifically includes a market evaluation, an evaluation of multiple EE/DSM program options, an EM&V plan (that would apply to the pilot programs at a minimum, and ideally to other future programs as well), and a clear timeline for program development milestones. NRLP should develop the EE/DSM plan concurrently with

the pilot EE/DSM offerings discussed above and use the plan and the results of the pilots to develop permanent offerings at the end of the pilot period.

- As a complement to the three programs discussed above, NRLP should develop a behavior-based DSM program that allows NRLP to communicate with customers as a means of reducing NRLP load during times of grid stress and during coincident peak hours. The communications could, among other things, inform customers about the three programs discussed above. For maximum effect, given the high proportion of students in NRLP's service territory, the program should be available to all electricity consumers in NRLP's service territory and not restricted exclusively to NRLP customers. NRLP should develop this as a pilot program as well and evaluate its effectiveness along with the other three pilot programs at the end of the pilot period.
- NRLP should consider adding a program focused on weatherization and building retrofits/upgrades, particularly for older less-energy efficient residential units.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-34, SUB 54

DOCKET NO. E-34, SUB 55

DOCKET NO. E-34, SUB 54 In the Matter of Application for General Rate Case DOCKET NO. E-34, SUB 55 In the Matter of Petition of Appalachian State University d/b/a New River Light and Power for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses	)))))))))))))	**Summary of Testimony of Jason W. Hoyle on Behalf of Appalachian Voices**

My name is Jason W. Hoyle. I am the Principal Energy Policy Analyst at EQ Research, LLC. In that role, I coordinate and contribute to EQ Research's various research projects for clients, provide oversight of EQ Research's electric industry tracking services and consulting projects, which includes preparing and reviewing analyses of rate case filings for electric utilities, and perform customized research and analyses to fulfill client requests. Prior to working at EQ Research, I was employed by the Appalachian Energy Center and the Center for Economic Research and Policy Analysis for nearly eighteen years in various positions that entailed, among other things, due diligence, regulatory compliance analysis, and pro forma financial and valuation analysis.

The purpose of my testimony is to (1) analyze New River Light and Power's (NRLP) overall rate of return (ROR), return on equity (ROE), cost of debt, and capital structure proposals; (2) provide alternative ROR, ROE, cost of debt, and capital structure proposals; (3) offer additional cost of capital recommendations to ensure that NRLP optimizes its capital structure going forward and updates its capital structure and ROR to reflect this optimization; (4) discuss NRLP's obligation to develop energy efficiency and demand side management (EE/DSM) programs that comply with the Commission's order in NRLP's last rate case; (5) provide an overview of the unique characteristics of NRLP residential customers, specifically as they relate to the potential opportunities and challenges of implementing EE/DSM programs; (6) analyze NRLP's tentative EE/DSM plans; and (7) present additional EE/DSM programming and planning recommendations.

More specifically, I find NRLP's originally proposed overall ROR of 7.007%, with a 9.60% ROE, 4.20% cost of debt, and 52% common equity to 48% long term debt capital structure to be unreasonable and unjustified because they are not cost based, violate accepted rate making standards, are benchmarked against inapplicable industry data and regulatory proceeding outcomes, and would therefore unjustly burden NRLP customers and improperly impact the transfer of NRLP profits to the Appalachian State University endowment fund under North Carolina law. I recommend that NRLP's proposals relating to ROR, ROE, cost of debt, and capital structure be rejected by the Commission, and recommend that the Commission instead approve a 6.25% ROE, 2.3% cost of debt, and 78% common equity to 22% long-term debt capital structure and require NRLP to both conduct a discounted cash flow analysis to optimize its capital structure and, if necessary, submit a compliance filing within a reasonable time frame that updates NRLP's capital structure and ROR in line with this discounted cash flow analysis.

I will note that NRLP and the Public Staff – North Carolina Utilities Commission filed an Agreement and Stipulation of Settlement on July 5, 2023 (the Stipulation), which "resolves all areas of disagreement between the parties" and proposes a 6.165% overall rate of return, 9.10% ROE, 3.23% cost of debt, and 50% common equity to 50% long-term debt capital structure for the Commission's approval. I would recommend that the Commission reject these proposals as well as they are not grounded in actual cost-based values, improperly incorporate risks to which NRLP is not subject, and would result in NRLP customers paying excessive, unjust, and unreasonable rates.

With respect to EE/DSM, I discuss the Commission's Order Accepting Stipulation and Granting Increase in Rates in Docket No. E-34, Sub 46 (Sub 46 Order), which requires NRLP to develop rate schedules and EE/DSM programs that capitalize on its advanced metering infrastructure (AMI) system. I note that NRLP has not formally proposed or filed any EE/DSM programs for the Commission's approval, even though none of its wholesale power supply related contracts prohibit or restrict EE/DSM programs. Given the unique characteristics of NRLP's residential customers, who earn less per capita than the statewide average, are highly mobile, and are comprised of a growing number of renters, I find that EE/DSM programs would have even greater beneficial impacts. NRLP has indicated that it is seeking grant funding to pursue heat pump and water heater rebate programs, electric vehicle charging infrastructure, and programmable thermostats that NRLP could control. While this is a promising start, I recommend that NRLP prepare and file an EE/DSM program plan that establishes overall goals, outlines guiding principles, provides benchmarks, evaluates EE/DSM program options, defines an evaluation, measurement and verification process and program review standards, and provides a timeline with specific milestones for program design, development, review, and modifications. In addition, I recommend that NRLP convert the three EE/DSM programs that it has tentatively identified into formal pilot proposals, develop a behavior-based DSM pilot program that enables NRLP to communicate with customers and consumers and encourage them to reduce their electricity usage during coincident peak periods, and consider weatherization and building retrofit/upgrades for its customers. I will note that the Stipulation is completely silent on EE/DSM, despite the fact that Sub 46 Order provides that "NRLP should work to develop rate schedules and energy efficiency and demand side management programs that take advantage of the detailed usage data and other capabilities of its AMI metering system" and NRLP's current wholesale power supply contracts do not prohibit or restrict EE/DSM programs, and for this reason (along with others), the Stipulation should be rejected.

MR. MAGARIRA: Thank you. Witness Hoyle is available for cross examination and questions from the Commission.

COMMISSIONER KEMERAIT: Public Staff?

CROSS EXAMINATION BY MR. FREEMAN:

Q. Good afternoon, Mr. Hoyle. Thank you, Commissioners. My name is Will Freeman. I'm an attorney for the Public Staff. If you are ready, I'd like to ask you a few questions.

I'd like to start with the overall rate of return, which I think you just addressed in your live testimony, and also addressed in your written testimony.

And if you're ready, I'm ready to proceed.

A. Yes, I'm ready.

Q. And I kind of noticed, as I was reading over your testimony, you file at the same time as the Public Staff. And I noticed a lot of things that you asked for were actually done. And, of course, you couldn't have known that when you filed. But one of the complaints I think that you had is that New River should conduct discounted cash flow analysis.

Does that ring a bell for you?

A. Yes. I believe that is one of the

recommendations.

Q. And you're aware that the Public Staff did conduct such an analysis?

A. Yes, I am now.

Q. Well, Mr. --

A. I was after reviewing the --

Q. Mr. Hinton's testimony is right there on the corner, if you would like to look at it. That's his testimony that we filed the same day that you filed, if that would help?

A. I have reviewed that, yes.

Q. Okay. And if you were to look at Mr. Hinton's testimony, I think that you'd say that his DCF results were between 8.64 and 9.20 percent. You might want to look at page 24, but I don't want to rush you.

A. (Witness peruses document.)

That is what it says, yes.

Q. And the settlement that we discussed has a 9.10 return on equity.

A. I believe that's correct.

Q. I don't have a copy of the -- I do have a copy of the Stipulation handy, if you don't.

A. I did bring that.

Q. Okay. If you'd look at page 4, paragraph 14.

A. Yes. 9.1 percent is what's in the Stipulation.

Q. So we have -- we did conduct the DCF analysis that you were worried that the Company hadn't conducted, and it yielded a result that contains within it the settlement number; is that correct?

A. Within the DCF analysis that Mr. Hinton conducted, that was based on publicly traded companies --

Q. Okay.

A. -- and dividend growth rates, neither of which apply to New River.

Q. Because it's a governmental entity?

A. Yes.

Q. Does it make any sense to you that a governmental entity might have an opportunity cost, even though it is a governmental entity?

A. That does make sense, and we did look into this. Appalachian State provides no cash into New River Light and Power. New River Light and Power's only sources of investment are debt capital and its retained earnings.

So the extent to which Appalachian State incurs an opportunity cost in regards to New River is that the University allows New River to occupy some very small amount of its overall debt limit.

Q. All right. Let's now talk about the cost of debt, if we can.

A. I'm yours to ask questions of.

Q. I'm not trying to browbeat you or make you -- I want you to say as much as you want to say on this topic, because it's your day.

I think you that you noted in your testimony that Appalachian State University's most recent debt was at 4.06 percent?

A. Which page is that?

Q. I believe it's on page 16 of your testimony.

MR. MAGARIRA: If I may, could you -- if you have the line number, could you direct Witness Hoyle to that line number, if you could?

Q. It's at line number 9 on the far right part of the sentence.

A. Yes. That is the interest rate on bonds to build a parking deck.

Q. 4.06 percent?

A. Right.

Q. Okay. And in this case, the recommended cost of debt in the stipulation is 3.23 percent?

A. So the parking deck in New River are very different, shall I say, operating divisions of Appalachian State. New River Light and Power, when debt is issued or obtained on its behalf, must repay that debt with its own revenues, as opposed to elsewhere. I cannot speak to the circumstance of the parking deck.

But Appalachian State's debt that it secured to finance a parking deck in 2022 is different than the debt that it has secured to finance New River Light and Power.

Q. Well, just big picture, we can say that the $20 million debt issuance was 80 basis points higher than agreed to in the settlement?

A. (Witness peruses document.)

Q. 83, I guess.

A. Yes.

Q. Thank you. Okay. Let me talk a little bit about capital structure with you.

And I think, in your testimony, you recommended using the actual capital structure; 78 percent equity and 22 percent debt, approximately.

Does that ring a bell?

A. Yes. That's very close.
Q. And you would agree with me that common equity is more expensive than debt?
A. Yes.
Q. In this case, like, far more -- like, more than twice as expensive as debt?
A. Well, New River Light and Power does not technically have common equity, it doesn't have shareholders, it doesn't have shares. Equity for a nonprofit -- which Appalachian State is a 501(c)(3) educational nonprofit, even though it is state controlled -- generally, builds up in whatever retained earnings.
Q. Well, I'm sorry, I didn't mean to cut you off.
A. No. That's the end of my statement.
Q. Okay. I want to say two things.
First, you're aware that New River pays taxes?
A. Yes, I was, as of reading the filings in this -- in this case.
Q. Okay. Second, if we use a 78 percent equity and 22 percent debt, by reducing the equity and increasing the debt capital structure, hypothetical for

ratemaking purposes, don't we save ratepayers money?

A. That could possibly be the case. You also obfuscate what's actually happening. Your -- the cost of debt is an actual cost, right? And that is a fundamental ratemaking principle. The rate should be made on the basis of cost. And my personal opinion in my testimony is that New River Light and Power should receive the cost of its debt. Not the cost of its debt plus some additional hypothetical portion of its capital, but the actual cost of its debt. Not more than the cost of its debt, because that would provide, sort of -- let's call them hidden returns. They are not really hidden, but they would not necessarily show up on a simple chart showing the capital structure and return on equity and cost of debt.

And, as we have seen in New River Light and Power and Appalachian State, it's a much more complex process to obtain that. So compared to, say, a utility -- a for-profit utility, perhaps with a publicly traded holding company parent, who might get issue bonds or refinance bonds fairly easily, New River Light and Power has a long, thorough process that could even potentially involve the Board of Governors for reviewing that. So their likelihood that their cost of

debt might change is fairly low.
Q. Okay. Thank you for your answers.
I'd like to just say, your recommended overall rate of return was 5.39 percent, correct?
A. (Witness peruses document.)
Yes, that's correct.
Q. Okay. And the Company, 7.007-or-so percent?
A. New River?
Q. New River's application, 7.007?
A. Yes.
Q. And the settlement, which I think you have in front of you, but I have one here, is 6.165 percent, which is in the middle but lower towards the ratepayer's favor of those two ranges; is that right?
A. I mean, I haven't calculated the average of 5.39 and 7.007.
Q. I was eyeballing it, but it's, like, 70 basis above yours and 80 below, right?
A. Some figure around there, yeah. It's certainly in between the two.
Q. All right. And this is lower than the Commission-approved rate of return from the 2017 case?
A. I believe so.
Q. That was 6.525 percent and this is

6.165 percent.

Does that sound right to you?

The order is right there on the corner of that desk if you would like to look, but I'll represent to you that's what it says.

A. I didn't pull the entire pile over here. If your representation is correct, I will accept that.

Q. A lower rate of return, all else being equal, results in ratepayer savings. All else being equal, right? If you change nothing but the rate of return, ratepayers' bills would go down?

A. Ratepayers would save money, yes.

Q. Okay. And the revenue impact, we know of this decrease from the utility's request is $315,000, in favor of ratepayers, and that is Fenge Settlement Exhibit 1, Schedule 1, which is also right there in front of you if you would like to look.

A. (Witness peruses document.)

Do you have a page?

Q. Schedule -- if you look at Exhibit 1, Schedule 1, kind of in the -- keep going. You're close.

A. (Witness peruses document.)

Yes. But this does not appear to be an

all-things-equal type of number. It does appear there are accounting adjustments from the Public Staff, which certainly goes beyond my testimony.

Q. I did not mean to conflict two concepts. I had, sort of, finished one topic, which is all things being equal, a lower ROR is good for ratepayers; and then move on to a second topic to monetize, in this case, unrelated to that question, the savings to ratepayers by this lower rate of return.

That was -- so that second topic, would you agree with me that, reducing the Company's requested rate of return to the amount in the settlement agreement, results in a ratepayer savings of $315,145?

A. Yes, that's what it says.

Q. Okay. If you'll give me one minute, please. Thank you.

(Pause.)

MR. FREEMAN: Thank you. I don't have anymore questions.

MR. STYERS: I have some questions this afternoon.

CROSS EXAMINATION BY MR. STYERS:

Q. Mr. Hoyle, my name is Grey Styers, counsel on behalf of New River Light and Power.

So if I read your testimony correctly, your recommendation is that the Commission should approve the capital structure of New River of 78 percent equity and 22 percent long-term debt; is that correct?
A. Could you give me a page reference?
Q. Well, I just -- I was asking about your recommendation for your --
A. I have a lot of pages here.
Q. -- your -- page 30, line 19 and 20.
A. (Witness peruses document.)
Yes, 78.3 percent equity and 21.7 percent long-term debt.
Q. And is the return on equity, the equity portion of that, 6.25 percent, correct?
A. That's correct.
Q. Okay. And that 6.25 percent, the starting place for your calculations was at 5 percent municipal bond rating; is that correct?
A. That's correct.
Q. Okay. And you were relying upon what you said recent municipal bond data showing that 5 percent rate for municipal bonds; is that correct?
A. Yes. Specifically, the A-rated municipal.
Q. Okay.

A. Or, actually, the B-rated municipal bonds. The level below the credit rating of Appalachian State.

Q. Municipal bonds are a form of debt, are they not?

A. They are.

Q. Okay. So you're recommending that the equity component of New River is financing be established based upon, calculated upon, a debt rate -- cost of debt for municipal bonds, correct?

A. Yes, that's correct.

Q. Okay. But you would agree that even the debt portion of New River Light and Power is not technically a municipal debt, is it not?

A. (No response.)

Q. Let me rephrase that.

New River's debt is not municipal debt, is it not?

A. New River secures installment loans from a bank, and those loans are -- do not function in a way similar to bonds. In fact, they require the repayment of principal almost from day one in most cases. This causes a number of issues with cash flow, because the term of these bonds is far shorter than -- or the term of these loans is far shorter than the appreciable life

the property that they are financing.
Q. So the question is no, New River Light and Power's debt is not the same as municipal debt?
A. New River's Light and Power's debt --
Q. -- is not municipal debt?
A. Appalachian State University's debt is tax free, in the same way that municipal debt is. As to whether debt funding of New River Light and Power is -- has a taxed advantage on an equivalent-based Appalachian State's, given the new tax status, I would say that I'm not an accountant, and I would recommend that you speak with a certified accounting professional.
Q. Okay. My question is not an accounting question, it's a finance question.
Simple question: The debt that New River Light and Power had would not be considered municipal debt; yes or no?
A. No, it would be similar to state debt.
Q. All right. Thank you.
So the municipal bond data that you reference for your 5 percent on page 29, that was shown on a chart on page 17, I believe, if I'm not mistaken, of your testimony.

Is that the type of municipal bond data that you are referring to, and you're setting a 5 percent starting point for your calculation?

A. Yes.

Q. I was actually looking at the source material. Even though that chart is not cited, I was able to find that source material.

Those municipal bonds that were shown in your chart on page 17, those were general obligation. Municipal debt is a general obligation bond, is it not? Are you familiar with the concept general obligation bonds?

A. Somewhat.

Q. Okay. So municipal debt is a general obligation bond, is it not?

A. Perhaps.

Q. General obligation bonds are backed by the full faith and credit of the issuer, correct? That's, kind of, the definition of the general obligation bond?

A. Right. That's exactly how Appalachian State University's bonds are.

Q. Okay. So are you familiar with the concept full faith and credit for general obligation bonds?

A. I have not reviewed it for this particular testimony, no.

Q. Subject to check, full faith and credit general obligation bonds are backed by the taxing authority of municipality.

Assuming that's correct, is it your understanding that Appalachian State has taxing authority?

A. Appalachian State's bonds are backed by the State of North Carolina, is my understanding. It's a division of the State of North Carolina's university system.

Q. The Appalachian State, itself, is not a taxing authority?

A. Not that I'm aware of.

Q. Okay. So there is no full faith and credit of a taxing authority to tax its residents to support general obligation bonds like there is for municipal debt, is there?

A. I really can't answer with those technical terms, as I mentioned. I did not review these technical terms. I don't recall seeing them in any of the other testimony.

Q. It's your understanding that general obligation bonds typically have a lower interest rate than a revenue bond because it is backed by the full faith and credit of the issuer?

A. Again, I would repeat my previous answer.

Q. Okay. You recognize that municipal debt is tax free debt; it's a nontaxable debt on municipal debt?

A. Yes.

Q. And you said that New River Light and Power is a taxable entity because it has to pay unrelated business income tax, correct?

A. New River Light and Power is -- pays unrelated business income tax, as the operating division of Appalachian State, but I don't know that I would call it a taxable entity. It's not technically a separate entity, except for purposes like ours today. It is a part of Appalachian State, and Appalachian State is a nonprofit.

Q. But you understand that --

MR. MAGARIRA: Commissioner Kemerait, I would object to this line of questioning. It's asked and answered, and also just pretty cumulative.

I think the line of questioning, I mean -- I think, from what Witness Hoyle has said, I mean, obviously, he's opined upon, sort of, what the bonds are in question, and whether or not they can be taxed. I feel like he's answered the question already.

MR. STYERS: I would be glad to move on. I was just exploring the basis of the 5 percent, and I'd like to move on, if I may.

COMMISSIONER KEMERAIT: Then I will go ahead and sustain the objection.

Q. Mr. Hoyle, then based upon that 5 percent number you drew from municipal tax data, then you added 1.25 percent to that, did you not?

A. I did.

Q. Okay.

A. Because in order to obtain financing -- this is required under the Hope decision of the Supreme Court, that rates should be set at a level that permits a utility to obtain financing --

Q. So let me ask you about the basis --

A. -- that --

Q. I'm sorry.

A. -- New River is allowed to obtain. The only financing New River has available is debt. So in order to obtain financing, you have to provide enough cash flow to ensure that the lender's minimum discount service coverage ratio is met.

So you cannot just say that having the cash flow or return of 5 percent on a bond with interest rate of 5 percent. That is not sufficient to obtain financing. There has to be additional cash flow, typically 20, 25 percent. I use 25 percent in this case. That is the additional 1.25 percent above the bond rate.

Q. So you understand the public debt is generally issued through an underwriting process, is it not?

A. I've never issued public debt.

Q. Okay. Are there, to your knowledge, financial advisors involved in the issuance of public debt, or do you know?

A. I would presume there are financial advisors.

Q. Okay. Bond counsel often involved in the issuance of public debt?

A. I would imagine there are a large number of people and titles involved in the issuance of public debt.

Q. In coming up with your 1.25 percent and your overall 6.25 percent return on equity, did you talk with or consult with any financial advisors in coming up with that number?

A. No.

Q. Any bond counsel?

A. No.

Q. Any underwriters?

A. No.

Q. Public debt is generally purchased by constitutional investors, which is pension funds, insurance companies, or exchange-traded funds.

Have you talked with any institutional investors about their rate of return expectations for public debt?

A. No.

Q. And if I asked you the same questions about risk analysis of university and utility systems, you haven't talked to anyone regarding how the market would analyze risk factors for publicly owned utilities debt -- publicly -- risk factors for publicly owned utility systems, have you?

A. New River Light and Power is not a publicly owned utility; but no, I have not asked about publicly owned utility debt.

Q. Now, you did cite, on page 29, a footnote 54 that you did look at a Moody's investment municipal utility revenue bond methodology.

MR. STYERS: And I'd like to hand that up, if I may, as an exhibit.

COMMISSIONER KEMERAIT: Mr. Styers, let's first mark it for identification purposes, and we'll mark it as New River Cross Examination Hoyle Direct Exhibit 1.

(New River Cross Examination Hoyle Direct Exhibit 1 was marked for identification.)

MR. STYERS: Or Response Exhibit 1? Direct Exhibit 1?

COMMISSIONER KEMERAIT: Direct Exhibit 1.

MR. STYERS: Okay. Thank you.

Q. So is this the report that you --

A. Can you direct -- you mentioned there was a citation somewhere.

Q. Bottom of page 29, footnote 54.

A. (Witness peruses document.)

Q. Is this the report that you had cited in your footnote on the bottom of page 54?

A. Yes. In regards to the 1.25 percent above the base level of 5 percent.

Q. And you actually pinpoint cite pages 8 and 9, so I'll direct you to pages 8 and 9.

So is there anything on page 8 and 9 that talks about, kind of, a 1.25 percent increase over your municipal base rate calculation to come up with your presumed return on equity?

A. (Witness peruses document.)

So the 1.25 percent is not a random number. That is 25 percent above the 5 percent base level. That is the additional cash flow above what is required to service the 5 percent debt that a lender would require.

You can see Exhibit 3, under the financial strength, debt service coverage. These are debt service coverage ratios for borrowers with different credit ratings.

Q. So this is --

A. 1.25 percent -- that's a 1.25, under column Baa, that is a credit rating below the level of Appalachian State's credit rating, which I also believe accounts for some of the additional risk and financial market uncertainty to use the requirements for the credit rating level below where Appalachian State actually is. That applies both to the 5 percent and the 1.25.

Q. In this utility revenue debt methodology, there is a number of factors and subfactors that are listed, starting on page all the way back to 5, and that financial strength calculation on page 8 is one of numerous factors that this report lists, is it not?

MR. MAGARIRA: Could you direct him to -- I think you said starting at page 5.

MR. STYERS: I'm just asking about the report. He cited it. I'm just saying, there is numerous factors, starting as early as page 5, that is covered by this report. And I'm just asking if would he agree that there were various factors and subfactors listed in utility revenue debt methodology, such as asset condition, service area wealth, system size, financial strength, and/or debt service, et cetera.

Q. You would agree those are all factors listed in this report?

A. Those are all factors listed in the report.

Q. In your testimony, did you cite any of these other factors in determining a -- what you believe to be, a rate on equity, other than just the debt service ratio?

A. No, I did not. The financial strength, which debt service ratio is a part, is the largest single factor, and it is also a very commonly applied metric for lenders. In a sense, they will not lend money to someone that does not have the cash flow to pay the interest on their debt, as well as a bit of an extra margin in case, for whatever reason, cash flows that the Company might decline for a short period of time.

Q. Is there -- is there anywhere in this entire 24 page report in which there is any reference to equity or return on equity?

A. I couldn't say without reading the report directly or having a digital copy to search.

Q. Okay. So let me help you. I understood your answer. Let me -- subject to check, let me confirm that I have done a search, and the only place where I could find the word "equity" is on the last page, on page 24. And it's highlighted there towards the bottom in yellow.

And if I'm reading it correctly, would you confirm that this report states that, Moody's credit rating is an opinion as to the credit-worthiness of a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors?

Is that what that sentence reads?

A. That's what that sentence reads.

Q. All right. So I think you have already discussed with the Public Staff about the DCF analysis that you submit that New River should have performed.

Did you, yourself, submit a DCF analysis as part of your report in this case?

A. I did not.

Q. Did you undertake, yourself, any DCF analysis on New River Light and Power?

A. I have not.

Q. Have you done a DCF analysis for any utility in your career?

A. Yes.

Q. Okay. Have you testified to that analysis?

A. No.

Q. Okay. So having done a DCF analysis, you are aware that the analysis involves numerous inputs, does it not?

A. It does.

Q. Okay. And depending upon those inputs, the output of a DCF can vary widely, can it not?

A. That's true.

Q. Okay. So when you made a recommendation of a some type of compliance filing a DCF analysis, you acknowledge that DCF analysis output can depend upon the inputs that are made in doing that analysis?

A. Could you direct me to what you are referring to, please?

Q. I don't have it right here in front of me, but is it your testimony that there should be a DCF analysis that's presented -- page 46, line 17 and 18, make the recommendation that New River should submit a compliance filing following completion of a DCF analysis; is that your recommendation?

A. That is. And the compliance filing should reflect -- should include the DCF analysis and reflect the recalculated rate of return and capital structure.

If you look at the prior recommendation, I also recommended that New River develop a comprehensive financing strategy. Part of the reason for this is I believe New River should conduct a discounted cash flow analysis. I do not believe that analysis should depend upon growth rates of dividend payments.

New River Light and Power does not have a dividend payment like a for-profit company or a division of a for-profit publicly traded company.

The closest you could get -- I'm not gonna concede that any for-profit company is technically a comparable that would be appropriate in our risk basis used in such an analysis. But if we were to go down route, I understand that the way things are commonly done.

The appropriate growth metric to use would be one that New River actually has that can be compared, which would be a growth metric based on retained earnings.

Q. But you've agreed with me that the output of a DCF analysis can vary widely, based on the input assumptions that go into that analysis?

A. Yes.

Q. Okay. Do you -- I think you said in your introductory remarks that you provide a rate case service for utilities over 50,000 customers.

Did I understand that correctly?

A. Analysis of rate case filings.

Q. Analysis of rate case filings for utilities over 50,000 customers, correct?

A. Yes.

Q. Do you know how many customers New River

Light and Power has?

A. Not precisely, but I'll say somewhere maybe around the 15,000, 20,000 range.

Q. So subject to check, New River has around 8,800 customers.

So are you -- do you know how much it would cost a small utility to have a consultant do a DCF analysis?

A. No.

Q. So you wouldn't contest that the cost of that type of analysis by a consultant can well exceed $50,000? You'd have no basis to contest that?

A. I would have no basis to contest that.

Q. Is there any Commission order or rule that requires a DCF analysis to be filed by a utility in a rate case?

MR. MAGARIRA: Objection, to the extent that he's asking for a legal opinion from our expert.

MR. STYERS: Just asking if he knows.

THE WITNESS: I'm not familiar with --

COMMISSIONER KEMERAIT: Let me rule upon the objection. The objection is overruled, and answer the question as -- to the best of your ability.

THE WITNESS: I'm not familiar with any such rule.

Q. Okay. Are you aware that smaller utilities in North Carolina often file rate cases without a DCF analysis?

A. No, I'm not aware. I mostly work in electricity.

Q. So you acknowledge -- so shifting now to EE/DSM. I just want to make sure -- I'm shifting gears here away, and I just have a few questions in this arena. I will refer you to page 42 of your testimony.

You cite, on pages 10 and 11, a number of variables that go into designing an EE/DSM program, do you not? A program design, incentive levels, expected savings, expected program costs, program evaluation, measurement and verification plans, et cetera.

A. You mean lines 10 and 11.

Q. Lines 10 and 11, excuse me.

A. (Witness peruses document.)

Those are program details that would be informative, yes.

Q. So the success of the DSM/EE program would depend upon a number of these variables, would you not agree?

A. I would not describe it as a success. I mean, the success of an energy efficiency or demand side management program would really depend on the objectives of the program. Those objectives -- these variables would, perhaps, inform the determination of whether a program's objectives were met, or inform the design of a program that was intended to meet those objectives.

Q. But you were saying you were not able to evaluate possible programs because you haven't evaluated those variables, and you don't have a firm conclusion because you don't have answers to those variables?

A. We received a bulleted list of identifying programs from New River Light and Power. That was the extent of the information, was essentially the name or general one-sentence or one-clause description of the programs they had identified.

Q. Without additional detail, such as these variables that you identified yourself on lines 10 and 11, you don't know, you know, the number of subscribers who would participate in any particular type of program, do you? That's the type of information you would need?

A. I don't know that anybody could know that for sure; but you could certainly develop information in the planning process that might provide some indication of interest by various stakeholders, including participants.

Q. But that does require planning process, does it not?

A. It does.

Q. And that's kind of what you discussed on page 43, the very next page.

And there you have listed various components of an EE/DS -- DMS [sic] program plan, did you not?

A. I did.

Q. Such as -- again I'm -- establishing the goals, setting forth principles, characterizes and benchmark the residential sector, evaluates the variety of options, defines the evaluation measurement verification.

Those are all parts of a -- necessary parts of an EE/DMS [sic] plan that you listed here, would you agree?

A. Yes.

Q. Now, you also stated that you acknowledge that New River is a small utility with very little experience in this area.

A. Yes. Their previous wholesale power contract and other related contracts essentially prevented the development of these types of programs.

Q. So it does not have any internal staffing, to your knowledge, to perform this type of planning?

A. I'm not familiar with the capabilities of the internal staffing of New River.

Q. Okay. Has App Voices recommended any expenses or costs be added to the revenue requirement in this case in order to cover DSM/EE costs?

A. Not to my knowledge.

Q. To the extent that grant funding would not be available, are you suggesting that New River design, propose, and implement such a own program at its own expense?

A. Most utilities implement programs at expense. They also recover those costs. They also make sure that those programs do not cost more than the value that they add.

Q. So you would agree that those would be reasonable costs for a utility to incur and recover from ratepayers?

A. It's possible that they could be reasonable costs.

Q. Okay. Testifying today under oath, do you know how much it would cost New River Light and Power to implement your recommendations that you've stated on page 44? You made recommendations on page 44. Do you know how much those would cost New River?

A. (Witness peruses document.)

Not specifically. I've not prepared a budget or an estimate. But I will point out that Appalachian State has a lot of departments that work in these types of areas.

The economics department has familiarity with doing evaluations of these types of programs, designing certain types of programs. We have a building science department that is very familiar with energy efficiency and building codes, as well as things beyond what I could even describe. The efficiency of certain appliances and building envelopes.

New River Light and Power has a large number of resources available that I believe would not only support the educational mission of the university, but also allow it to help develop some of these types of planning documents and program design concepts at a much lower cost than might be obtained from a much larger utility.

Q. But do you have any knowledge of any of those departments having ever designed an EE/DSM program for a utility? Do you have any knowledge of that?

A. No, not having designed one.

Q. Okay. And you don't know what the costs would be per customer or per kilowatt hour to implement your recommendations on page 44, do you?

A. No. That is the point of the planning process.

Q. Yeah. And you don't identify any specific revenue stream to fund the types of DSM/EE programs you have identified, do you?

A. Not in this testimony, no. I am aware of available funds.

MR. STYERS: No further questions. Thank you.

COMMISSIONER KEMERAIT: Redirect from Appalachian Voices?

MR. MAGARIRA: Thank you, Commissioner Kemerait.

REDIRECT EXAMINATION BY MR. MAGARIRA:

Q. Just a couple of questions for you,

Mr. Hoyle.

During -- I think it was counsel for Public Staff, they asked you a couple of questions with respect to, I believe, if I'm recalling correctly, the DCF analysis, specifically the fact that the Public Staff had recommended and conducted a DCF analysis in its own testimony, and that the Stipulation ROE and ROR were a function of that DCF analysis.

Do you recall that line of questioning?

A. Somewhat, yes.

Q. Do you, at any point, recall seeing, in any of the settlement testimony that was filed with the Stipulation, any reference to the DCF analysis being, I guess, the product or informing the ROR cost of capital terms?

A. I do not recall reference to the DCF analysis in this settlement.

Q. And there's the Stipulation, at all, talk to how New River, on a going-forward basis, will optimize its capital structure or cost of capital?

A. No.

Q. Okay. Can you talk a little bit in some depth with respect to your recommendations specifically about cost of capital and DCF analysis? There's some questions from counsel for New River and Public Staff with respect to what you've recommended, and I think there is maybe just a little bit a lack of clarity with respect to maybe the understanding of what you are recommending.

A. Yeah. So my recommended return on equity is based on the cost to procure debt, because that is the only type of capital that, as far as I'm aware of, New River Light and Power can procure. That is one of the key objectives from the Hope ruling, is that the rates of return be set to allow utilities to attract capital.

There is a fundamental problem with discounted cash flow analysis, the risk premium analysis, the capital asset pricing model analysis that are typically undertaken that is specific to New River Light and Power, because of its status as an operating division of a nonprofit, state-controlled educational institution. That problem is that New River Light and Power doesn't pay dividends. It doesn't have shareholders. It doesn't have a dividend growth rate.

So to begin with that series of analysis, you need to find comparable utilities on a risk basis. Well, those fundamental risks that these analysis start with is dividend growth rates, right? That is an investor risk, and that simply just doesn't exist. There is no reasonable proxy for that with New River Light and Power.

So, to me, that was kind of a non- starter. I could not identify utilities with comparable risks literally at the foundational level of these analyses.

There are certain aspects of New River's operations that might be considered comparable; say its size, like a municipal electric provider, but those don't have regulated rates, so those are not before the Commission. We don't have methods related to those.

So the closest thing is, what can we do to still fulfill the requirements of the Supreme Court, set a rate of return that is reasonable, and provides access to capital? That's where we begin with the municipal bond ratings plus the additional cash flow, the additional return necessary to allow New River to access capital.

Q. And with respect to your, I guess, recommendation regarding the compliance filing, can you explain a little more about, sort of, what you had proposed with respect to what New River would file and the purpose of that compliance filing?

A. Can you point me there?

Q. Yeah, I can. So this would be, I believe -- just bear with me. So this would -- excuse me. This would be page 30, and I think, just starting at line 9, you sort of start talking about what you're specific recommendation is with the compliance filing and the need for, sort of, the comprehensive analysis.

A. Right. So there is a lot that is missing, in my opinion, from New River Light and Power's proposal.

If you recall the testimony that was available, I believe they used two natural gas utilities as the complete list of comparable utilities. Which, to me, suggests that they also had a difficult time finding comparable utilities on a risk basis, and they kind of skipped over the investment risk part and went to something that are distribution-only utilities, and looked more at operational risks than the initial starting point of investor risk.

And well, if they -- so I suggest that they follow up. Develop some more information and either explain why they cannot pursue this, or develop a mechanism that would allow them to pursue it.

As I mentioned before, if you find a way around the comparable risks and you do manage to identify utilities that might be acceptable or comparable in risk to New River, you still run into the problem of growth rates based on dividend payments. The only way possible around that, since New River has no dividend payments, is to make a comparison on the basis of something that New River doesn't have that these other utilities also have, and that is retained earnings.

So there are ways that, plausibly, you could substitute in or conduct a discounted cash flow analysis, even if you are trying to compare New River Light and Power nonprofit with a division of a large for-profit, publicly traded utility Company.

I did not take that approach. But I do recognize that it's an available approach that would get as close as possible through the type of comparisons that are normally presented to the Commission.

Q. Thank you. And I have two additional questions with respect to the line of questions from the Public Staff.

So first, at one point, counsel for Public Staff, they had mentioned that, based on the capital structure approved in the Stipulation, that capital structure, essentially, was needed in comparison to the actual capital structure -- the capital structure that you recommended -- because a hypothetical capital structure was gonna be more favorable to ratepayers.

Do you remember that line of questioning?

A. Yes, I remember that.

Q. But that would only hold if you have a, I guess, hypothetical structure that is coupled with an ROE that's higher than necessary. Would you agree with that?

A. I'm sorry, can you --

Q. Sorry, I will rephrase that.

A. -- bring it all back together into one --

Q. Yeah. So, basically, counsel for Public Staff said we need the capital structure that was proposed in the stipulation, because an actual capital structure, the one that was proposed, if you have that capital structure coupled with the ROE, that is gonna be worse off -- worse for ratepayers.

Do you recall that?

A. Yes, sir, I recall that.

Q. That only holds if you have an ROE that's inflated?

A. Right. That would be, if you applied the proposals from -- in my opinion, the proposals from the

Public Staff and New River Light and Power regarding the return on equity to New River Light and Power's actual capital structure, it's a well-recognized thing amongst the Public Staff witnesses and New River's witnesses that this would be a vastly excessive rate of return.

So instead of considering or adjusting the ROE, they just adjust the capital structure to try to lower the overall rate of return. I prefer to deal in facts where facts are able.

Q. And last question, counsel for Public Staff, they reference a bunch of proceedings and basically said that the ROR -- and these are past proceedings involving New River -- that the ROR that was agreed to -- specifically the ROE that was agreed to in the stipulation was lower than those prior proceedings.

Do you recall that?

A. Yes.

Q. Is it proper, in determining what the right ROR or ROE is, to refer to prior ROEs that were authorized to approved by the Commission?

COURT REPORTER: Excuse me, can you repeat that question please? I've lost you.

MR. MAGARIRA: Sorry.

Q. Is it proper, in determining what the correct cost of capital is, to refer back to returns on equity that were approved in other proceedings?

A. It could be. It depends on whether those proceedings are partly recent, but whether they also involve utilities with comparable risks.

Q. Okay. Thank you. Moving on to the line of questioning from New River's counsel. I believe you got a series of questions with respect to the Moody's investor service report that was the basis for your 1.25 percent additional coverage figure.

Do you remember that?

A. Yes.

Q. I guess just at bottom, your approach, again, would you agree it's based on the information that was provided by New River, based on the actual cost values that were provided in this proceeding?

A. Yes. That's where my capital structure came from, was the values provided by New River, as well as the cost of debt proposed, is what was provided by New River as their imbedded costs.

Q. And so the -- you know, you using, basically, municipal bond rates, that's, again, your attempt to find what were actual cost values that represent the financing costs that New River would experience if it were to finance capital?

A. No. No, that was actually an attempt to provide a risk adjusted rate of return that would be assured -- as close as to assured as we can get, anyway -- to allow New River to access capital. Their actual capital costs would be lowered, even if they were obtaining municipal bonds, because I use the 5 percent rate. That is the rate for -- for a credit rating one level below the credit rating of Appalachian State.

And so Appalachian State should actually be able to access capital at a lower price, a lower rate, than what a worse-off entity with a lower credit rating would be able to access capital at.

Q. Okay. Thank you. And just a couple questions with respect to energy efficiency and demand side management.

Counsel for New River asked a couple of questions with respect to, sort of, the cost of it implementing energy efficiency programs, creating a plan.

You would agree that New River would probably be best placed to, sort of, provide information with respect to how much it would cost for salaried employees or other planning costs that would be incurred?

A. Yes. It would require significant input from New River, and quite possibly Appalachian State as well, to understand those details, as well as the general concept of what these plans might look like and involve.

Q. Right. And in addition, New River, obviously, identified in its rebuttal testimony that it had applied for a grant funding for these EE/DSM programs, correct?

A. Yes.

Q. Okay. And, ultimately, sort of identifying these costs was beyond the scope of your testimony?

A. Yes.

Q. Okay.

MR. MAGARIRA: No further questions.

MS. LaPLACA: Commissioner, I'd like to ask questions if I can.

COMMISSIONER KEMERAIT: Ms. LaPlaca, going forward, if you have not reserved any cross examination time, please let me know, and I will give you some leeway. This is a little out of turn to allow you to ask a question. So I will allow you to ask a brief couple of questions, but keep it very brief, since you did not -- you did not reserve any cross examination time, and your cross examination is out of turn after redirect has happened.

MS. LaPLACA: Okay. Thank you.

COMMISSIONER KEMERAIT: So please be brief.

MS. LaPLACA: Thank you.

CROSS EXAMINATION BY MS. LaPLACA:

Q. Mr. Hoyle, Appalachian State University has a sustainable technology department, correct?

A. Yes, that's correct.

Q. And within that sustainable technology department, they have building science experts, correct?

A. That's correct.

Q. In fact, Lee Ball, who is the director of sustainability at Appalachian State University, has an advanced degree in building science; is that correct?

A. I believe so, but I am not completely certain.

Q. So you would say that there is quite a bit of expertise at Appalachian State University when it comes to building science and energy efficiency, correct?

A. Yes, I can say that for sure.

Q. Okay. Thank you very much.

COMMISSIONER KEMERAIT: Since the cross examination was out of turn, is there any additional redirect from Appalachian Voices that is necessary?

MR. MAGARIRA: No redirect.

COMMISSIONER KEMERAIT: Okay. So we'll move on to Commission questions.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q. Mr. Hoyle, you have testified that you don't have any information or have not calculated how much -- and this question relates to the DSM/EE program testimony and your recommendation.

And you testified that you don't have any information about how much DSM/EE program would actually cost. There's -- what I'm more interested in is the funding for it or how that cost recovery would be recovered. And you testified about grant funding.

Are there any other mechanisms or ways that New River Light and Power could recover the costs, other than through funding through grants?

A. Give me a second.

Q. Yes.

A. I'm considering how to answer this. New River Light and Power's financials, let's say their use of the debt instruments that they currently use, leave a lot of money on the table; or not actually on the table, they put a lot of money back in the bank's pocket that is unnecessary and, in my opinion, kind of unreasonable.

There should be, were New River Light and Power being managed like or even close to the way that a utility would typically be managed, in terms of its use of debt, $600,000 in recent years. I wrote down numbers. In 2023, it appears from what I -- let's see, in Exhibit -- Mr. Halley's Exhibit 13, there would be -- New River Light and Power would paying $665,000 on the principal on loans that it obtained in 2016 and 2020. That's very unusual.

Some of those loans are financing capital projects that are -- aren't even in service yet. They have been repaying the principal on projects before they are in service, even before -- much less before they recover the capital cost of those projects through the depreciation expense in their rates.

The terms of these loans are far shorter than the service life of these -- this property. They are putting in property with service lives, depreciable lives, in excess of 30 years. They are funding that investment with loans that have a term of 10 or 20 years. Which means that that creates a significant cash flow shortage, and that is certainly one source of funding that could be available.

If New River Light and Power or Appalachian State were financing using debt in a manner that would be typical of a utility, then they would have a significantly larger amount of cash flow and significant amounts of money to available to invest in these programs, also available to invest in other activities and other needs, such as reserves for volatile commodity markets.

Q. So as a follow-up to that -- to your answer to that, New River witness Miller testified that New River does not qualify for DSM/EE cost recovery that would be available to other electric utilities pursuant to the General Statute §62-133.8 and §62-133.9.

Are you familiar with those statutes, and do you agree with his statement that New River would not have that type of cost recovery that other electric utilities would?

A. I am somewhat familiar with those statutes and the implementing rules of the Commission in that regard.

As far as the cost recovery part and New River's eligibility, to my mind, that kind of interacts with New River's very unique position in Commission. As I recall, they are not considered a public utility under state law, but are still rate regulated by the Commission.

I wish I could give you more of an answer, but I'm not an attorney, and I'm not comfortable trying to weave my way through that particular swamp.

Q. Okay. Understood. So let me check to see if my fellow Commissioners have any questions for you.

COMMISSIONER KEMERAIT: Okay, Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Hoyle, based on your -- some of the dialogue you had on redirect, it -- sort of a question that's really more for my curiosity, probably, than may change the outcome the case.

Whether or not I get to the same place you do, is something I haven't yet decided, but I do start with the same point that you make, which is that, for purposes much Hope and Bluefield, comparability is a really important issue. And you discussed your criticism of the Company's attempt to use investor-owned and regulated public utility gas distribution companies. I understand your critique. But that prompts the question of curiosity here.

So what we've got before us here is, at least in North Carolina, it's a little bit of a unicorn. You know, it's a state instrumentality -- instrumentality of a sovereign, but it can't charge its own prices. Its prices are set by another agency of the State, based on cost of service and cost of capital.

Well, is it -- I mean, is there another herd of unicorns running around somewhere else in the United States? Are there similar entities that are state instrumentalities regulated by state agencies, public commissions like this Commission in other states? Have you gone looking for them?

A. I have not found any, aside from Western Carolina, which is the state with the same circumstances.

Q. Right.

A. But I'm not aware of any, I have not seen any. In my Company, we track utility regulations and regulatory commission activities in all 50 states. Nobody -- as I said, I lead the rate case proceeding. Nobody in the past year and a half, since working there -- 15 months, whatever -- has sent me an email saying, "Here's this interesting strange thing happening you might want to know about," like a unicorn. I have not found any that are treated similarly in other states.

I mean, honestly, the issue goes back -- same reason Western Carolina has the utility, right? The hydroelectric dam that was created in 1915 that has become what is now New River Light and Power, well, it's the mountains. They wanted light for their teacher's school. It was gonna be another 20 years before the Rural Electrification Act got passed. Who knows how long before they actually got the wires up there. So we're talking generations, potentially, of people who would not have had electricity for use in education, you know, had New River Light and Power not been created for that purpose, just like Western Carolina.

But in terms of finding other utilities in the same circumstance, I have not been able to find any.

Q. Or even other business enterprises, state-conducted business enterprises that may be subject to rate regulation. Railroads, for example, or other enterprises that might be subject to rate regulation in other states.

I ask the question because, if we can find them, I'd be interested in knowing how rate regulation and cost of capital is viewed in those -- in those circumstances. But we don't have that. You looked for it, and you can't find it?

A. I haven't looked for railroads. I mostly focused on electricity companies.

Q. That's fine.

A. But I understand what you're saying, and a more broad search with a broader scope, that perhaps included the full scope of utilities, could perhaps be useful as to identify what else is being done in other places.

Q. Thank you. Like I said, just curious. Thank you.

COMMISSIONER KEMERAIT: I believe that all of the parties are very familiar with how we handle questions on Commission questions, but just as a refresher, any questions from the parties on Commission questions have to be related very directly and very specifically to just the questions that have been asked by the Commission.

So beginning with the Public Staff, any questions on Commission questions?

MR. FREEMAN: No questions. Thank you, Commissioner.

COMMISSIONER KEMERAIT: Okay. Ms. LaPlaca?

MS. LaPLACA: No, thank you, Commissioner.

COMMISSIONER KEMERAIT: New River?

MR. STYERS: Yes.

EXAMINATION BY MR. STYERS:

Q. To follow up with Commissioner Clodfelter's questions, he referenced Western Carolina. That's the first time it's been referenced in this hearing room.

Have you looked at the rate case results and the rate of return on equity that's been set by this Commission for Western North Carolina?

A. No, not recently. But I suspect it's been set in similar ways as New River Light and Power has been set in the past.

Q. So subject to check, the most recent rate case of 2020, the cost of equity for Western North Carolina was 9 percent; and 2016, Western Carolina's rate of equity was 9.25 percent.

Subject to check, would you agree with those numbers?

A. They are in the dockets, right? You could present them if you wish.

Q. Yeah. Finally, regarding the fact that this is sort of a unicorn, would you agree that, in looking at rates of return, you look at overall risk? That's one of the driving factors, would be risk-adjusted rate of return, correct, as a financial principle?

A. For equity investor, absolutely.

Q. And so the risks include -- and you've discussed financial risks, correct?

A. (No response.)

Q. Financial risk would be one type of risk?

A. That would be one type of risk.

Q. But there's also -- in addition to financial risk, companies have similar operating risks, do they not?

A. Operating risks are another type of risk.

Q. So similarly situated utilities might have

similar operating risks, would they not?
A. It's possible.
MR. STYERS: Okay. No further questions.
COMMISSIONER KEMERAIT: Mr. Hoyle, thank you for your testimony, and you may be now excused.
We will hear motions from the parties.
Oh, I apologize. Appalachian Voices, did you have any questions on Commission questions?
MR. MAGARIRA: Thank you, Commissioner Kemerait.
COMMISSIONER KEMERAIT: I spoke too quickly.
MR. MAGARIRA: It's all good. I have two questions, real quick follow-ups.
EXAMINATION BY MR. MAGARIRA:
Q. At one point, you were asked just generally about the prospects of New River being able to avail itself of the EE rider for cost recovery.
Do you recall that?
A. Something along those lines, yes.
Q. Just want to, kind of, button this up.
Just as a general matter, you're aware of that, but ultimately, at the end of the day, you can't

really opine upon this, because that's, kind of, like, a legal opinion? Aware of the issues, but just not in a position to share anything with regards to that?

A. Yes. I mean, I could say if their rates are -- New River's rates are regulated. Riders are generally considered a rate.

Q. Okay. Thanks.

MR. MAGARIRA: No further questions.

COMMISSIONER KEMERAIT: Okay. Mr. Hoyle, I was excusing you too quickly. Now you may be excused, and thank you for your testimony.

THE WITNESS: Thank you-all very much.

COMMISSIONER KEMERAIT: I will now hear motions from the parties, beginning with Appalachian Voices.

MR. MAGARIRA: Thank you, Commissioner Kemerait. At this time, Appalachian Voices would move to have Mr. Hoyle's prefiled direct testimony exhibits and his prefiled testimony be entered into the record as though if given orally from the stand, and have the exhibits attached to his prefiled direct testimony identified as premarked. And again, we would move that Mr. Hoyle's live supplemental testimony that was given from the stand today be moved into the record.

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

(Exhibits JWH-1 and JWH-2 were admitted into evidence.)

MR. STYERS: Commissioner Kemerait, New River Light and Power would ask that New River Light and Power Cross Examination Hoyle Direct Exhibit 1, previously identified, be moved into the record as evidence.

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

(New River Cross Examination Hoyle Direct Exhibit 1 was admitted into evidence.)

COMMISSIONER KEMERAIT: And before we move on to the next witness, Ms. LaPlaca, I think that we need to go back to your testimony, because your exhibit was not moved into the record.

Would you like to make a motion?

MS. LaPLACA: Sorry about that. Yes, I would like to move to have an exhibit put into the record, please. I brought 20 copies.

COMMISSIONER KEMERAIT: That's not necessary.

MS. LaPLACA: Okay.

COMMISSIONER KEMERAIT: But seeing no objection, your motion is allowed.

MS. LaPLACA: Okay. Thank you. Apologies.

(LaPlaca Attachment A was admitted into evidence.)

COMMISSIONER KEMERAIT: And, Appalachian Voices, you may call your next witness.

MR. JIMINEZ: Thank you, Commissioner. Nick Jimenez with the Southern Environmental Law Center for App Voices. Appalachian Voices calls Justin Barnes to the stand.

COMMISSIONER KEMERAIT: Mr. Barnes.

Whereupon,

JUSTIN BARNES,

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

COMMISSIONER KEMERAIT: And we are going to allow your attorney to make the introduction and request that testimony be admitted into the evidence -- into the record, and then we're gonna take our afternoon break for 10 minutes. So you may proceed.

MR. JIMENEZ: Understood, thank you.

DIRECT EXAMINATION BY MR. JIMENEZ:

Q. Mr. Barnes, please state your name and business address for the record?

A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Road, Suite 202, Cary, North Carolina.

Q. And could you briefly describe your role and responsibilities at your employer?

A. I'm the president at EQ Research, which means I largely oversee a lot of EQ Research's policy tracking products, regulatory tracking, legislative tracking, general rate case tracking, IRP tracking, as well as oversee a lot of our consulting projects, specifically those that tend to deal with quantitative analysis, cost of service rate design, and that sort of thing. I also periodically offer expert witness testimony on those topics.

Q. Mr. Barnes, did you cause to be prefiled in Docket Numbers E-34, Sub 54 and Sub 55 on June 6th direct testimony consisting of 75 pages, including four exhibits?

A. I did.
Q. Do you have any changes or corrections to your prefiled testimony at this time?
A. I don't have any corrections.
Q. If the questions put to you in your testimony were asked at the hearing today, would your answers be the same?
A. They would be.
Q. Were the exhibits to your testimony prepared by you or under your direction?
A. Yes, they were.
Q. Mr. Barnes, did you also cause to be prefiled in those same two dockets, on July 6th, a summary of your testimony consisting of five pages?
A. Yes, I did.
Q. Moving to the Stipulation, have you had a chance to review the Agreement and Stipulation of Agreement between New River Light and Power and Public Staff filed on July 6th?
A. Yes, I have.
Q. Have you had a chance to review the settlement testimony of Randall Halley filed on behalf of New River Light and Power in those same two dockets on July 6th?

A. Yes, I have.

Q. And have you had a chance to review the settlement testimony of John R. Hinton and James McLawhorn, both of whom were filed -- both of which were filed on behalf of the Public Staff on July 6th?

A. Yes, I have.

Q. Please briefly describe the Stipulation terms concerning the schedule NBR, the proposed net billing schedule, if you would?

A. Well, basically, the stipulation adopts schedule NBR largely as New River Light and Power proposed it. That includes the New River Light and Power's proposed supplemental standby charges. Those -- those are incorporated in slightly different amounts, due to other changes that affect the revenue requirement, and I presume New River Light and Power's addition of separate standby charges for the commercial class and the commercial demand class. But, kind of, more or less, the stipulation adopts New River Light and Power's proposal with the -- with the review of schedule NBR and the supplemental standby charges in five year's time.

Q. What concerns do you have with the

Stipulations provisions concerning schedule NBR?

A. My concern is that the customer class supplemental standby charges, the SSCs, as reflected in the settlement testimony and exhibits, fail to accurately reflect cost causation.

The class SSCs incorporated within the settlement based on a flawed methodology for assessing the cost that New River Light and Power avoids, due to the installation of customer-sided solar, because they retain the same basic calculation and mathematical errors that I describe in detail in my direct testimony.

Specifically, those calculators -- calculations inappropriately underestimate the benefit side of customer-sided solar cost-benefit analysis in two significant ways.

First, they base the calculation of avoided costs for demand-related cost on an averaged flat volumetric rate, which fails to account for the fact that New River Light and Power incurs demand-related costs, based not on average demand, but demand that is coincident with the timing of its monthly peak. So cost based on coincident peak demand.

Second, those calculations entirely ignore the potential value of avoided distribution costs. Both aspects are contrary to proper cost-benefit analysis, and together result in an inflated SSC that will ultimately overcharge customers that install on-site generation.

Q. In light of those concerns, what recommendations do you have for the Commission regarding the stipulation?

A. I recommend that the Commission, to the extent schedule NBR portions are separable from the rest of the stipulation, reject those portions and adopt my recommendations for the establishment of schedule NBR, as described in my direct testimony.

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

COMMISSIONER KEMERAIT: Can you clarify the number of pages in the direct testimony? I thought you said 75 pages, but my notes show 56 pages. So can you provide some clarification?

MR. JIMINEZ: That was including exhibits.

COMMISSIONER KEMERAIT: Okay, including exhibits.

So Mr. Barnes' direct testimony filed in this docket on June 6, 2023, consisting of 56 pages of testimony, would be copied into the record as if given orally from the stand, and Exhibits 1 through 4 will be marked for identification purposes as prefiled.

MR. JIMINEZ: Thank you.

(Exhibits JRB-1 through JRB-4 were identified as they were marked when prefiled.)

(Whereupon, the prefiled direct testimony and prefiled direct summary of Justin Barnes were copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-34, SUB 54
DOCKET NO. E-34, SUB 55

DOCKET NO. E-34, SUB 54	)
	)
In the Matter of Application for General Rate Case	)
	)
DOCKET NO. E-34, SUB 55	)
	)
In the Matter of Petition of Appalachian State University d/b/a New River Light and Power for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses	)

DIRECT TESTIMONY OF

JUSTIN R. BARNES

ON BEHALF OF

APPALACHIAN VOICES

JUNE 6, 2023

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I. Introduction

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

A. My name is Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is President of EQ Research LLC.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of Appalachian Voices (AV).

Q. Have you previously submitted testimony before the North Carolina Utilities Commission (NCUC or the Commission)?

A. Yes. I have submitted testimony in Commission Docket Nos. E-2 Sub 1219 and E-7 Sub 1214 addressing the respective Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC) 2019 rate cases, and in Commission Docket Nos. E-2 Sub 1142 and E-7 Sub 1146 addressing the Duke Energy affiliates' 2017 rate cases.

Q. Please describe your educational and occupational background.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at North Carolina State University for roughly five years as a Policy Analyst and Senior Policy Analyst.[1] During

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

that time I worked on the Database of State Incentives for Renewables and Efficiency (DSIRE) project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst, became the Director of Research in 2015, and became the President of EQ Research in May 2023. In my current position, I coordinate and contribute to EQ Research's various research projects for clients, provide oversight of EQ Research's electric industry tracking services and consulting projects, and perform customized research and analyses to fulfill client requests.

Outside of North Carolina, I have submitted testimony before public utility commissions in Colorado, Georgia, Hawaii, Kentucky, Michigan, New Hampshire, New Jersey, New York, Oklahoma, South Carolina, Texas, Utah, Virginia, Wisconsin, and the City Council of New Orleans[2] on various issues related to distributed generation (DG) and distributed energy resource (DER) policy, net metering, general rate design and DG customer rate design, cost of service and cost allocation, utility ownership of DERs, avoided cost rates for qualifying facilities (QFs), and customer-sited battery storage program design. These individual regulatory proceedings have involved a mix of general rate cases and other types of contested cases. My curriculum vitae is attached as Exhibit JRB-1. It contains summaries of the subject matter I have addressed in each of these proceedings.

[2] The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state public utility commissions.

Q. Please describe the purpose of your testimony and how it is organized.

A. My testimony addresses three topics, which I have separated into the following sections:

- Section II addresses: (a) the establishment of a net energy metering (NEM) tariff by Appalachian State University d/b/a New River Light and Power (NRLP) in the form of a proposed, new Schedule NBR, including the Standby Supplemental Charge (SSC) proposed as part of this tariff, and (b) a buy-all, sell all DG tariff option in the form of Schedule PPR.
- Section III addresses NRLP's proposal to increase the residential basic facilities charge (BFC) from $12.58/month to $14.50/month.
- Section IV contains my concluding remarks and summarized recommendations.

Q. Please summarize your recommendations to the Commission regarding NRLP's Schedule NBR proposal and the reasons for those recommendations.

A. The Commission should approve the establishment of Schedule NBR, but with several modifications to the design NRLP proposed. My primary recommended modification is the elimination of the SSC component, which is supported by my analysis of the costs avoided by NRLP by residential customer-sited solar generation. My analysis, which corrects for certain errors in NRLP's own analysis, indicates that the value of such generation is approximately equal to the residential retail rate. As a consequence, the SSC is unnecessary as a means of protecting non-participants from a cross-subsidy and would overcharge Schedule NBR participants.

Specifically, I have calculated that exclusive of NRLP's marginal distribution costs, the value of residential customer-sited generation is in the range of 11.8 – 13.7 cents/kWh compared to a proposed residential retail rate of roughly 14.8 cents/kWh. I state this as a range because the specific value depends on assumptions used for solar system orientation, which impacts the contribution to the various peak demands that cause NRLP to incur costs. Based on available information about NRLP's distribution costs, layering an avoided distribution capacity benefit on top of the amounts for non-distribution avoided costs would likely eliminate the remaining cost/benefit deficit (1.1 – 3.0 cents/kWh) due to the relatively good alignment between solar production and NRLP's distribution system peaks.

I also recommend that the proposed Schedule NBR be modified to eliminate the provision requiring the annual forfeiture of accrued net excess credits on January 1 of each year. Instead, Schedule NBR should be modified to allow indefinite carryover of accrued credits, or in the alternative, allow a customer to choose their annual period. This change is justified because: (a) it is necessary to allow customers to size a system to fully offset their annual on-site energy consumption; (b) indefinite rollover provides a simple and effective deterrent against oversizing; and (c) given the results of my evaluation of solar benefits, no such "haircut" to customer compensation for customer-sited PV installations is justified.

Q. Please summarize your observations and recommendations regarding NRLP's proposed Schedule PPR.

A. The proposed Schedule PPR is a buy all, sell all tariff which would prohibit customers with qualifying behind the meter solar systems from using their system output to offset their energy consumption, and require those customers to sell all their output to NRLP at an avoided cost rate and buy all their power from NRLP at the retail rate that would apply to their customer class. I recommend that the Commission decline to approve Schedule PPR because it:

- Bars qualifying customers from enjoying the full benefit of their solar systems by prohibiting them from consuming the energy they generate on-site;
- Bases the compensation rate on a solar valuation methodology that I demonstrate is inaccurate; and
- Could be confusing to prospective DG customers given that its eligibility requirements significantly overlap those of Schedule NBR.

To the extent that NRLP might intend for Schedule PPR to deter retail rate customers who might otherwise be inclined to "oversize" their solar systems above the system cap Schedule NBR imposes, there are more effective ways of accomplishing that objective, such as imposing a cost-based charge on over-sized solar systems if those larger systems impose additional, unnecessary costs on NRLP.

Q. Please summarize your recommendations to the Commission on the proposed increase in the residential BFC.

A. The Commission should deny NRLP's proposal to increase the residential BFC to $14.50/month, and direct NRLP to reduce the residential BFC to no more than $10.61/month. My recommendation is based on my separate calculations of residential customer-related unit costs using three different methods. One calculation is based largely on NRLP's methodology for determining the BFC, with certain modifications to improve its accuracy, as explained later in my testimony. This calculation produces a residential BFC of $11.49/month. The second is an alternative calculation that I conducted using what is often termed the Basic Customer Method, which is a common method of setting BFCs throughout the country. This calculation produces a residential BFC of $10.61/month.

Finally, I have calculated alternative BFCs of $10.81/month for residential customers and $14.86/month for commercial general customers based on AV Witness Hoyle's calculations of an appropriate cost of capital and applying the resulting class revenue requirements reductions to reduce the BFCs for these customer classes. In sum, these three methodologies, when applied properly, result in a BFC ranging from $11.49/month down to $10.61, representing a reduction of $3.01 to $3.89 from NRLP's requested

BFC. On the balance, a maximum charge of $10.61/month most appropriately captures the multitude of competing factors involved.

II. Proposed Schedule NBR and Schedule PPR

A. Summary of the Schedule NBR Proposal & Summarized Response

Q. Please briefly summarize NRLP's proposed Schedule NBR.

A. Schedule NBR, as proposed by NRLP in its initial filing, has the following key elements:[3]

1. Available to residential and non-residential customers that install behind-the-meter ("BTM") photovoltaic ("PV") systems, with the system size capped at the lesser of the customer's anticipated annual peak demand, or 20 kW for residential customers and 1,000 kW for non-residential customers.
2. An energy netting regime that could be referred to as "Retail NEM" because it allows for the netting of imports and exports over the course of a monthly billing period (i.e., NEM) and the carryover of net monthly excess generation at the retail rate to the following month (i.e., the Retail in Retail NEM).[4]
3. An annual reconciliation mechanism where any accrued credits for excess generation are zeroed out on January 1 of each year.

[3] NRLP Application, Exhibit B – Proposed Tariffs.
[4] NRLP response to AV 2-3(a).

4. An additional charge on participant customers referred to as the SSC, which is set at $6.17/kW of AC nameplate capacity of the PV system, which NRLP proposes to base on the AC capacity of the inverter.[5]

Q. How does NRLP explain its proposed design for Schedule NBR?

A. NRLP witness Halley states that Schedule NBR was designed to meet the criteria provided in N.C.G.S. § 62-126.4.[6] As relevant to the design of Schedule NBR, the principal criterion that Witness Halley refers to appears to be N.C.G.S. § 62-126.4(b), which provides as follows:

> The rates shall be nondiscriminatory and established only after an investigation of the costs and benefits of customer-sited generation. The Commission shall establish net metering rates under all tariff designs that ensure that the net metering retail customer pays its full fixed cost of service. Such rates may include fixed monthly energy and demand charges.

Q. Does the proposed Schedule NBR provide nondiscriminatory treatment of customer generators that is based on the costs and benefits of customer-sited generation?

A. No. Most significantly, the SSC component of proposed Schedule NBR conflicts with the statutory directive that rates be "nondiscriminatory" because it is based on an erroneous analysis of the "costs and benefits" of customer-sited PV generation. I describe the errors in NRLP's calculation of the SSC in Section II(B) of my testimony. As a consequence, the SSC would cause customer-generators to pay more than their net "fixed cost of

[5] NRLP response to AV 5-2(a).
[6] Direct Testimony of Randall E. Halley ("Halley Direct") at p. 47.

service" given the relative costs and benefits associated with customer generation.

Q. Please discuss the specific problems that you have identified with the proposed Schedule NBR.

A. There are numerous problems with the proposed SSC and how NRLP calculated it based on its assessment of solar costs and benefits, the conceptual design of the proposed SSC and its applicability, and one structural issue with Schedule NBR. The deficiencies that I have identified are listed and described below, with identifiers to the more specific sub-issue(s) to which they relate.

1. SSC Issue #1 (Cost-Benefit Evaluation): NRLP's evaluation of the costs and benefits of customer-sited solar makes a basic methodological error by basing the calculation of avoided cost benefits on the volumetric residential retail rate, rather than the unit costs associated with the demand-based cost elements that produce the retail rate. This is erroneous because retail rates for these components represent the costs of peak demand as averaged over overall class usage, not the value of a given kilowatt ("kW") of demand reduction. The conflation of averaged costs with unit costs of peak demands causes NRLP to understate the costs avoided by customer-sited PV generation even if one accepts all of the other elements of its methodology.

2. SSC Issue #2 (Cost-Benefit Evaluation): NRLP's evaluation of the costs and benefits of customer-sited solar production relies on solar production data of highly questionable reliability in order to determine the effective solar capacity contribution towards peak demand hours. Specifically, there is an extreme amount of missing hourly data (roughly 30% of total daylight hours), which NRLP attempted to "fill in" using a methodology that is inconsistent with the shape of a solar production profile.
3. SSC Issue #3 (Cost-Benefit Evaluation): NRLP fails to include reduced distribution system loading and accompanying avoided distribution capacity benefits in its evaluation based on a simple blanket and unsupported assertion that its distribution costs are fixed.
4. SSC Issue #4 (Charge Applicability & Calculation): NRLP proposes to apply the SSC to all Schedule NBR customers, including non-residential Commercial General and Commercial Demand customers, but its determination of costs and benefits is based on, and specific to, residential rates and the residential rate structure (i.e., the volumetric retail rates are a basic input). Therefore, even if one agrees with the conceptual design of the SSC and NRLP had correctly calculated the costs and benefits of customer-sited solar, the proposed SSC rate would be incorrect if applied to non-residential rate classes.

5. SSC Issue #5 (Charge Applicability & Calculation): NRLP proposes to levy the charge based on the AC nameplate capacity of the customer's inverter rather than the system design capacity.[7] Leaving aside the other issues with the SSC that I have described, this charge determinant is mis-aligned with NRLP's methodology for determining the amount of the proposed SSC, which at its core is based on PV system energy production. Energy production is determined by the design capacity of a system, which for customer-sited PV is often lower than the inverter rating due to the fact that inverters come in standardized sizes that do not precisely line up with the production capability of the system.
6. Dual Schedule NBR & SSC Issue (Annual Reset and Charge Calculation): NRLP's proposal to zero out accrued excess generation on January 1 of each year is misaligned with NRLP's SSC calculation, which implicitly assumes that customers would be able to fully utilize all system production to offset retail purchases from NRLP as part of the "cost" side of its evaluation of customer-sited PV costs and benefits. In NRLP's SSC calculation, it made no adjustment to reflect the fact that its "costs" (i.e., customer savings) would be reduced by credits that are forfeited due to the reset. Furthermore, this provision would limit

[7] On a similar note, I would also add that NRLP Witness Halley mistakenly calculates system AC nameplate rating based on the maximum hourly *coincident* production of NRLP's customer solar generation sample. In practice, the AC nameplate rating of an individual PV generation system is reflected by its maximum generation in *isolation* from any other PV system. However, this inaccuracy does not appear to impact the resulting calculation of the proposed SSC as applied to AC system capacity because he makes a symmetrical error by using this measure of AC nameplate capacity as the denominator in the calculation of PV capacity contributions during peak hours.

customers' ability to size their PV systems to fully offset annual on-site energy needs, because it would result in forfeited credits for a typical 100% offset PV system.

Q. Has NRLP provided any further information on its proposal subsequent to the initial filing that relates to the problems that you have identified?

A. Yes. In response to data requests, NRLP indicated that it intended to make supplemental filings addressing items (4) and (6) listed above. Specifically, as it relates to item (4), NRLP stated that it intended to make a supplemental filing proposing separate SSCs for the Commercial General and Commercial Demand rate classes.[8] Regarding item (6), NRLP indicated that it intended to make a supplemental filing eliminating the annual reset of customer excess credit balances.[9] However, thus far, NRLP has made no such supplemental filings.

B. NRLP's Methodology for Analyzing Customer-Sited PV Benefits is Erroneous and Underestimates PV Benefits

Q. Please briefly describe NRLP's evaluation of the costs and benefits of customer-sited PV that underpins the proposed SSC.

A. NRLP performs a calculation using residential rates under which the costs of customer-sited PV are determined by applying estimated system production to the volumetric retail rate, which is the rate at which customer

[8] NRLP response to AV 2-3(b).
[9] NRLP response to AV 2-3(d).

savings accrue. For example, the calculated annual cost of a system that produces 5,000 kWh annually for a customer with a retail rate of $0.10/kWh would be $500.

The benefits are derived by applying a percentage contribution to those same retail rates based on how solar production aligns with how those costs are incurred. For the wholesale energy component of rates, this percentage is set at 100%, which reflects the fact that customer-sited PV generation reduces wholesale energy purchases at a 1:1 ratio. For the cost components that are determined based on monthly peak demands, NRLP calculated a solar capacity contribution using production meter data from existing residential PV installations for the hours during the test year in which those peaks occurred. I discuss the reliability of these calculated solar capacity contributions in Section II(C). In any case though, NRLP applies these solar contribution percentages to the following cost items as reflected in its cost-of-service study ("COSS"):[10]

- DEC Transmission (29.12%)
- Blue Ridge Electric Membership Corporation ("BREMCO") Transmission (29.12%)
- Carolina Power Partners ("CPP") Production Demand Related (26.03%)
- CPP Production Energy Related (100%)

[10] Exhibit REH-19A.

Applying these percentages to each individual cost component of residential retail rates and summing the results produces NRLP's calculated solar avoided cost rate (i.e., the solar benefit) of roughly 8.9 cents/kWh. This compares to a total residential retail rate of roughly 14.8 cents/kWh (i.e., the solar cost).[11] The proposed SSC is calculated by first multiplying the supposed benefit "deficit" by expected annual PV production to produce a revenue deficit amount ($/year). Next, NRLP translates that amount to the proposed SSC by dividing it by NRLP's estimate of PV AC nameplate capacity (kW) to produce a $/kW-month SSC. Specifically, the total net benefits deficit (after accounting for solar capacity contributions) is roughly $3,000/year, which is divided by a calculated, existing residential PV systems' nameplate capacity of 40.485 kW, and then divided by 12 months to produce the proposed SSC of $6.17/kW-month.[12]

Q. Does NRLP assign any benefit component to avoided distribution costs?

A. No. NRLP's calculations of solar benefits are confined to its wholesale energy supply and transmission costs.

Q. Do you agree with any aspects of this calculation of NRLP's solar costs and benefits evaluation?

A. Yes. Some aspects of the calculation are entirely appropriate. For instance, in general, assuming that customer-sited solar customers are able fully to

[11] Exhibit REH-19B.
[12] Exhibit REH-19A.

benefit at the retail rate from all production from their systems, the retail rate multiplied by solar production is appropriate for establishing the "cost" side of the cost-benefit equation. I also agree that it is appropriate to apply solar contribution percentages to individual cost sources in order to properly attribute cost avoidance driven by solar. Along these lines, the 100% factor applied to energy-related costs is reasonable, and in concept, it is also reasonable to apply capacity contribution percentages to those costs that are incurred based on different measures of monthly coincident peak demand.

Q. What aspects of NRLP's methodology are erroneous?

A. There are two primary deficiencies. First, it is not appropriate to use the volumetric retail rate as the "value" rate for demand-related costs. The retail rate is the rate at which a customer saves money, but it cannot be used to calculate a solar value rate because the volumetric retail rate is an <u>averaged cost</u> derived by dividing total costs ($) by total class usage (kWh). As a consequence, it does not reflect the actual cost of demand during the specific peak hours that cause NRLP to incur costs. Using it as NRLP does in the solar value calculation greatly understates the quantifiable benefits of customer-sited generation.

The solar value rate must instead be calculated by first dividing those same total costs ($) by the units of demand from which they are incurred to produce a demand unit cost ($/kW), adjusting that cost as necessary to reflect solar coincidence (%), and then dividing that amount by total solar production rather than class retail sales. Stated another way, the $/kWh retail rate is determined by class load factor, whereas the $/kWh solar value rate is determined by solar capacity factor. Those factors are invariably two different numbers. The relevant equations that produce both rates are specified in Table 1 below.

Table 1: Components of Rate Calculations

Class Retail Rate Components & Calculation	
Class Retail Rate ($/kWh)	**Class Demand Cost ($) / Total Class Energy Sales (kWh)**
Total Demand Cost ($)	Wholesale Demand Cost ($/kW) X Total Peak Demand (kW).
Class Demand Cost ($)	Total Demand Cost ($) X (Class Peak Demand / Total Peak Demand).
Solar Value Rate Components and Calculation	
Solar Value Rate ($/kWh)	Class Demand Unit Cost ($/kW) / Solar Production (kWh) X Solar Coincidence Factor (%)
Class Demand Unit Cost ($/kW)	Class Demand Cost ($) / Class Peak Demand (kW).
Solar Coincidence Factor (%)	Derived by alignment of solar production with peak hours

To be perfectly clear, this is an error in NRLP's calculation that is unrelated to any subjective judgment on how to conduct a value of solar evaluation. In that respect, it is the equivalent of a math error.

Q. Please describe the second error in NRLP's analysis.

A. NRLP fails to ascribe any avoided distribution capacity value to customer-sited PV generation. This is erroneous because all utilities have marginal distribution costs, and by definition, any marginal cost has the potential to be avoided because it has not yet been incurred. The simple fact that some costs have already been incurred, and as such are "embedded," does not change the fact that marginal costs invariably exist, and those future costs are avoidable. The full exclusion of this benefit component (i.e., assumed to be zero) artificially lowers the calculated benefit amount.

Q. Can you further illustrate why NRLP's use of volumetric retail rates in its calculation of solar value is in error?

A. Yes. One obvious implication of NRLP's methodology is that it caps the solar value rate at the class retail rate. For instance, under NRLP's method, the CPP Demand Related Component has an effective retail volumetric rate of $0.025459/kWh, which is derived by dividing the total revenue requirement for that cost ($1,578,131) by total class energy sales (61,988,218 kWh), and effectively spreads out the costs incurred by demand during peak periods across all customer usage. NRLP then calculates a solar value rate by multiplying that rate by a solar coincidence factor (26%) to produce its stated solar value rate of $0.006628/kWh for CPP Production Demand Costs. NRLP's algebraic calculations cannot produce a solar value rate that is higher than the class retail rate.

This is misaligned with how NRLP incurs CPP Production Demand Related costs and how a portion of those costs are assigned to a given class, which are both based on demand during 12 monthly peak hours. Critically, total annual class energy sales have nothing to do with either the incurrence of these costs, or their allocation to individual classes. In practice, the cost of a kWh used during one of the 12 monthly peak hours (the unit cost) based on the proposed residential class revenue requirement is $15.97, not $0.025459.[13] When applied across 12 months, the total demand unit cost ($/peak kW-year) is $191.66. That is, if a hypothetical 1 kW customer-sited resource was 100% effective at reducing demand during a monthly peak hour, the monetary value of that demand reduction is $15.97, and if it did so during every monthly peak hour, the value would be $191.66. NRLP's methodology dictates that the maximum value that a 1 kW customer-sited resource could produce over a year is $33.16.

Q. Does NRLP employ a proper methodology for calculating the value of reductions in peak demand elsewhere in its general rate case application?

A. Yes. NRLP did employ the correct unit cost-based methodology for assessing the value of demand reductions during peak hours in its design of a proposed Interruptible Rate. In that proposed rate, the compensation due to a participant customer that curtails load during a monthly peak hour is set at the $/kW unit cost rate plus an adder for line losses. This same methodology is appropriate to use in the context of calculating a customer-sited solar value rate for demand-related rate components.

[13] Calculated based on REH-19A and REH-14. The wholesale cost is stated in terms of $/kW peak demand, but since it is based on an hourly measurement, it can also effectively be stated as a volumetric kWh rate. The annual demand unit cost in this case is $191.66/kW of average demand during the 12 monthly peak hours.

Q. To be clear, is NRLP's miscalculation of the value solar provides reducing peak demand related to how one calculates the *effectiveness* of customer-sited solar at mitigating costs caused by peak demand?

A. No. I used a "100% effective" assumption in the previous example for the purpose of simplicity. If a different solar effective capacity amount is used, the analysis in the previous example still applies, only it would result in lower dollar amounts.

Q. Please elaborate on why NRLP's decision to exclude any solar value contribution for avoided distribution costs is in error.

A. NRLP contends that its distribution costs are fixed in nature and uses that assertion as the basis for failing to include an avoided distribution capacity component in its solar value calculation.[14] While it is true that embedded costs that have already been incurred are fixed, that does not mean that no avoidable costs exist presently and into the future. All utilities have marginal distribution costs since the distribution grid is not static and new investments are continually being made. This is true regardless of whether a utility has conducted a marginal cost study, which NRLP has not.[15]

[14] Halley Direct at p. 48.
[15] NRLP response to AV 2-4.

Q. Are avoided distribution capacity costs commonly considered as a benefit category in solar cost-benefit analyses?

A. Yes. The resulting values often differ considerably from study to study depending on the characteristics of the individual utility system but their inclusion as a category of potentially avoidable costs is nearly universal.

Q. Is there reason to believe that avoided distribution capacity could constitute a meaningful benefit attributable to customer-sited PV systems in NRLP's service territory?

A. Yes, for two reasons. First, a solar production shape is fairly well-aligned with the timing of the NRLP monthly system peaks that are used to allocate distribution costs according to NRLP's attribution of distribution cost causation. I conducted two separate calculations of solar capacity contribution to distribution peaks, one based on the timing of the 12 monthly peaks NRLP used for its 2021 COSS, and one based on the AMI updated 2016 COSS that NRLP submitted to the Commission after the conclusion of its last rate case. For a rooftop-sited South-facing solar profile sourced from the National Renewable Energy Laboratory's (NREL) PVWatts Calculator,[16] the 2016 peaks produce an effective solar capacity contribution of 27.9% using an equal hour weighting, and 26.9% using a load-weighted average. For the 2021 COSS, the same system produces an

[16] *Solar Resource Data*, NREL, https://pvwatts.nrel.gov/pvwatts.php (last visited June 6, 2023).

effective solar capacity contribution of 32.7% using an equal hour weighting.[17]

Second, even though NRLP has not conducted a marginal distribution cost study, its embedded distribution costs can be known and are quite high. Based on NRLP's proposed residential revenue requirement, the embedded distribution unit costs are $227.37 per average peak kW-year. At an average distribution peak contribution of 30% and average solar production of roughly 1,300 kWh/kW, the solar benefit rate would be roughly 5.2 cents/kWh vs. a residential retail distribution rate of roughly 3.3 cents/kWh. I discuss the specific quantification of avoided costs using a corrected valuation methodology in Section II(D) of my testimony.

C. NRLP's Study of Customer-Sited PV Capacity Contributions Relies on Incomplete Data and Inaccurate Assumptions

Q. Please restate the problems that you have identified in NRLP's evaluation of customer-sited PV capacity contributions to different measures of coincident demand.

A. The most significant problems are: (a) the sheer amount of missing production metering data in the sample that NRLP relies on, and (b) the method NRLP used to fill in missing hourly data, which is inconsistent with a solar production shape. There are also other oddities within certain other

[17] I did not conduct a load-weighted evaluation for the 2021 COSS because system load amounts were not provided in NRLP's COSS. The difference is almost certainly de minimis given the 2018 results.

aspects of NRLP's sample (e.g., monthly solar production shapes that are highly inconsistent with typical solar production shapes). The sources of those strange characteristics may be attributable at least in part to missing data.

Q. How much data is missing from NRLP's solar production metering sample?

A. In total, the sample shows zero values for 29.3% of total hours during the prime 9AM – 5PM solar production period, and 30.5% for the period from 8AM – 7PM. It is possible that some of the zero readings are valid zero production readings, especially for the hours around dawn and dusk. However, in many cases the zero readings exist between other non-zero readings when some level of solar production would be expected (even if minimal) during hours not on the solar production margin. Table 2 shows the zero reading amounts for each of the 15 customers in the dataset for the 9AM – 5 PM window.[18]

Table 2: NRLP Solar Production Missing Hours (9AM - 5PM)

Customer	Missing #	Missing %
1	1,459	50%
2	900	31%
3	244	8%
4	1,543	53%
5	1,125	39%
6	260	9%
7	1,145	39%
8	252	9%

[18] Developed using NRLP's response to AV 2-2, Attachment.

9	2,252	77%
10	1,329	46%
11	327	11%
12	232	8%
13	393	13%
14	281	10%
15	1,103	38%
Total	12,845	29%

As shown in Table 2, the number of missing hours differ considerably by customer, with a few customers that have missing percentages of greater than 50% and a larger number with missing data well in excess of the average 29% threshold.

Q. How are these missing hours distributed from the standpoint of how they affect NRLP's calculation of effective solar capacity according to different measures of monthly coincident peak demand?

A. NRLP filled in estimated hourly solar production for roughly 18% of the monthly peaks associated with calculating the solar capacity percentage for DEC transmission peak hours and roughly 15% of the readings used to calculate the CPP production demand capacity contribution.[19] Given this, the missing data has the potential to meaningfully affect the results, to say nothing of the fact that the total amount of missing data raises reasonable questions about the basic reliability of the dataset.

[19] *Id.*

Q. How did NRLP estimate solar production for the missing hours in its coincident peak contribution dataset?

A. It averaged the difference between the last valid data reading before the interruption and first valid reading after the interruption over the intervening hours.[20] In effect, it assumed that the solar production profile was flat, or constant, during the missing hours.

Q. Is this an accurate method for estimating solar system production for missing data?

A. No. The level of accuracy progressively diminishes as the duration of missing readings lengthens because average hourly solar production varies along an upside down U-shaped curve centered on a peak at solar noon. On average, the average duration of missing data for the solar production amounts that NRLP estimated was 7 hours.[21] Over this duration, the accuracy of NRLP's estimation methodology could be exceedingly low as applied to individual hours.

Q. What are your conclusions regarding the validity of NRLP's solar capacity contribution evaluation?

A. The amount of missing data and the potential impacts that this missing data could have on the results raise serious questions about its validity. As a result, the proposed SSC for Schedule NBR, which relies in large part on

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[20] NRLP response to AV 5-3, Attachment.
[21] *Id.*

the solar capacity contribution evaluation, rests on insufficient evidence and should not be adopted.

D. A Corrected Evaluation of Customer-Sited PV Benefits Produces a Value Approximately Equal to the Retail Rate

Q. Please explain your analysis of solar benefits, including the corrections that you have made to NRLP's methodology.

A. There are two primary elements to my evaluation. First, in all of my calculations, I corrected the error that I previously discussed in NRLP's solar value equation to use residential class unit costs rather than residential class volumetric retail rates as inputs for calculating demand-related benefits of customer-sited PV.

Second, I analyzed the solar contribution to peak under five different scenarios in order to present a complete picture representative of the likely range of capacity contributions based on typical customer-sited solar orientation. To correct for the missing data underlying NRLP's analysis, I developed three analyses based on projected solar production data, for rooftop-sited systems oriented on a South, Southwest, and Southeast azimuth, respectively. I used these three system orientations to reflect the fact that site limitations sometimes preclude the "due South orientation" that is optimal for customers (i.e., maximizes energy production) and the fact that the capacity contribution amounts rely on hypothetical average production shapes rather than metered production data from actual installations.

I also conducted two analyses that rely on NRLP's solar peak analysis despite the insufficiency of NRLP's solar production data, in order to provide an apples-to-apples comparison to NRLP's analysis that should help the Commission assess the results of the three more accurate scenarios just discussed. In one, I simply applied the same solar capacity contribution methodology that NRLP used, arriving at a different result solely as a result of the solar value calculation methodology correction described above. In the second, I also corrected how nameplate AC capacity is calculated in NRLP's analysis, by relying on the sum of maximum single hour production from sampled systems, rather than the maximum coincident production of the system sample.

The results of each of these five analyses support the same conclusion: solar value is approximately equal to the retail rate.

Q. Please explain how you estimated the avoided distribution capacity benefits of customer-sited solar, given that NRLP did not address this benefit component.

A. As with other system costs, I used NRLP's proposed residential revenue requirement for NRLP Distribution and the monthly average residential class peak demand used to allocate those costs to calculate \$/kW unit costs. That is, the cost of distribution capacity is based on NRLP's embedded distribution costs rather than marginal distribution costs because NRLP's marginal distribution costs are not known.

I then calculated the solar capacity contribution percentage based on the relevant solar production profiles and the monthly peak hours identified in NRLP's 2021 COSS and its AMI updated 2016 COSS. This is conceptually the same as NRLP's methodology for calculating solar capacity contributions for demand-related costs. The specific capacity contribution multiplier I used is the average of the values based on the two COSSs. The solar value rate was calculated using the annual energy production from each solar production profile.

Q. What are the results of the analysis that you have conducted on the value of customer-sited PV in NRLP's service territory?

A. The resulting customer-sited solar values, as stated in terms of $/kWh of solar production, are considerably higher than NRLP's estimates. The principal reason for these differences is the correction of the solar value equation that I have previously described. With the exception of one scenario, my analysis actually uses lower solar capacity contributions than those used by NRLP in its evaluation in order to correct an error in NRLP's analysis related to its calculation of aggregate existing solar nameplate capacity. Nevertheless, the resulting solar values are higher due to the correction I made to the basic solar value equation. Table 3 shows the ultimate results of my analysis for each of the five scenarios. Further details of the calculation for each scenario are contained in Exhibit JRB-2 and my attached workpapers.

Table 3: Customer-Sited PV Value by Capacity Contribution Scenario

Metric	South Facing	Southwest Facing	Southeast Facing	NRLP	Corrected NRLP
Solar Value Rate ($/kWh)	$0.12269	$0.12821	$0.11760	$0.13707	$0.11922
Solar Value % of Retail Rate	82.6%	86.3%	79.2%	92.3%	80.2%
Deficit From Retail Rate ($/kWh)	($0.02580)	($0.02028)	($0.03090)	($0.01142)	($0.02928)
Values above assign a zero value for avoided distribution costs					
Estimated Avoided Distribution Cost Rate ($/kWh)	$0.05201	$0.04941	$0.05352	$0.05201	$0.05201
Solar Value Including Distribution ($/kWh)[22]	$0.17470	$0.17763	$0.17111	$0.18908	$0.17122
Solar Value % of Retail Rate	117.6%	119.6%	115.2%	127.3%	115.3%

Q. Based on your analysis, what can the Commission conclude about the value of customer-sited PV generation in NRLP's service territory?

A. According to my analyses, the value of customer-sited PV generation exceeds the residential retail rate by 15% or more when avoided distribution costs based on embedded costs are used in the calculation. Furthermore, the relative value stated in terms of the percentage of retail rate would reach 100% even if marginal distribution costs are steeply discounted relative to

[22] For the purpose of calculating avoided distribution capacity costs included in the two furthest right columns, I used the value from the South-facing production profile due to my concerns about the reliability of NRLP's production meter data.

embedded distribution costs. Retail NEM without NRLP's proposed SSC is justified from the standpoint of cost causation.

E. Schedule NBR Should Offer Retail NEM With Indefinite Carryover and No Standby Charge

Q. What are your recommendations to the Commission regarding NRLP's proposed Schedule NBR?

A. The Commission should approve the establishment of Schedule NBR with the following changes. First, Schedule NBR should not include the proposed SSC component. As I have demonstrated, after correcting for NRLP's solar value methodological errors, the value of customer-sited PV generation is greater than the residential retail rate, and therefore adopting Retail NEM would not result in any cross-subsidization from non-participant customers or NRLP.

Second, Schedule NBR should include a provision allowing for indefinite rollover of monthly energy credits for excess generation, rather than the proposed annual calendar year account reset. This change is sound policy because it is necessary to allow customers to fully offset their annual on-site consumption with customer-sited PV and benefit from that on-site energy production, which is consistent with state policy favoring the entire spectrum of demand-side options. The purpose of self-generation is to offset a customer's on-site energy needs and any limitations on that objective should be reasoned and justified rather than arbitrary.

It is justified from a ratemaking and cost-causation standpoint because my solar value analysis indicates that such a compensation "haircut" is neither necessary nor justified as a measure to mitigate cross-subsidies. It also retains and sends an implicit signal to customers that discourages oversizing by preventing a customer from benefitting from consistent excess production beyond their annual energy needs, since those credits would become "stranded" and could never redeemed by the customer.

Q. Is there any risk of cost-shifting associated with the application of Schedule NBR to non-residential rate classes?

A. Not really. Using the Commercial General rate class inputs, the solar value is 102% of the sum of non-distribution cost components and 79% of the total retail rate, without consideration of any avoided distribution costs. Adjusting both of those values to include avoided distribution capacity would produce results similar to my residential evaluation, since the solar contribution to system-wide distribution peaks would not change. Since the Commercial Demand rate class features demand rate components that solar customers would not be able to avoid, and correspondingly lower volumetric rates (i.e., a lower cost of customer-sited generation in terms of solar customer savings), the potential risk of subsidization of customer-generators within that rate class is even lower.

Q. Is it necessary that a DG tariff design for NRLP customers entirely eliminate the potential for cross-subsidization?

A. No. As a practical matter doing so is impossible because there are unavoidable uncertainties involved, and cost attribution is inherently an exercise in approximation. Therefore, an approximate solution is sufficient and reasonable.

F. Schedule PPR Is Punitive and Suboptimal

Q. Please describe proposed Schedule PPR.

A. Proposed Schedule PPR, or "Purchased Power from Renewable Energy Facilities (a.k.a. Buy All/ Sell All)," is a separate NRLP tariff available to all customers who operate qualifying, behind the meter solar generation. In contrast to Schedule NBR, customers participating in Schedule PPR would effectively be prohibited from using their solar systems' output to offset their energy bills. Instead, participating customers would be required to buy all their power from NRLP at the relevant retail rate[23] and sell all their solar output to NRLP, for which they would receive $0.089039 per kWh per month in energy credits as compensation.[24] The AC capacity for qualifying systems could not be designed to exceed 1,000 kW and would need to operate parallel with NRLP's distribution system.[25] In addition, qualifying

[23] ASU, along with other participating customers, would pay the retail rate that applied to its customer class. *See generally* NRLP responses to AV DR 6-1, 6-3 (summarizing the current buy all, sell all riders and describing differences in the proposed buy all, sell all rider established under schedule PPR).
[24] Application, Ex. B at 27.
[25] NRLP response to AV DR 6-6.

systems must be "manufactured, installed, and operated in accordance with all applicable government regulatory and industry standards and must fully conform with . . . NRLP's applicable interconnection standards."[26]

Q. Who may enroll in Schedule PPR?

A. Witness Halley states that although NRLP has proposed its net billing rate schedule, Schedule NBR, NRLP will "continue to offer the existing buy all / sell all option to purchase renewable energy at its avoided cost rate from its customers."[27] According to Exhibit B to NRLP's Application, Schedule PPR is available to "Sellers who operate a photovoltaic (PV) generation energy source in parallel with New River Light and Power Company's (NRLP) system."[28] According to NRLP's responses to discovery requests, Schedule PPR would replace existing schedules SPP Demand, SPP No Demand and SPP Fixed (existing buy all/sell all).[29] NRLP has four rate schedules, R (Residential Service), G (Commercial General Service), GL (Commercial Demand Service), and A (for ASU).[30] Accordingly, Schedule

[26] Application, Ex. B at 27.
[27] Halley Direct at p.3.
[28] Application, Ex. B at 27.
[29] NRLP response to AV DR 6-3. However, NRLP's filings in the most recent avoided cost proceeding suggest that these rate schedules would continue to be offered to Public Utility Regulatory Policies Act ("PURPA") qualifying facilities ("QFs") that are not eligible for Schedule NBR or Schedule PPR; if that is not the case, it is not clear what rate schedule NRLP would use for a QF. New River Light & Power's Compliance Filing of Rates and Contracts, *Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2021*, Docket No. E-100, Sub 175 (N.C.U.C. Dec. 5, 2022).
[30] NRLP response to AV DR 6-5. NRLP has proposed to close schedule GLH, which currently has no existing customers. NRLP response to AV DR 6-6.

PPR would be available to customers on each of these rate schedules, in place of the existing buy-all-sell-all schedules.

I will also mention that there could be some customers for whom Schedule PPR would appear to be the only option. Schedule NBR is available to customers on Rate Schedules R, G and GL who operate solar PV systems for their own use, in parallel with NRLP's system, but the solar PV array must "not be designed to exceed the Customer's anticipated annual peak kilowatt demand or 20 kilowatts (kW) for a residential system or 1,000 kW for a non-residential system, whichever is less."[31] Accordingly, Schedule PPR would be the only option for ASU and for residential customers with system sizes larger than the caps described above. In addition, because both Schedule NBR and Schedule PPR apply only to solar PV systems, there does not appear to be a schedule proposed for other types of renewable energy resources or for facilities over 1,000 kW, except for Schedules SPP Demand, SPP No Demand, and SPP Fixed, filed in the most recent avoided cost proceeding (Docket No. E-100, Sub 175). These schedules contain a compensation formula but are unclear about the rate charged for electricity consumed and the customer-generator's right to self-consume. Although customer deployment of other forms of renewable energy resources might be relatively unlikely, I will note that ASU currently

[31] Application, Ex. B at 24.

operates a wind turbine, which appears to be compensated outside the buy-all-sell-all construct.[32]

Q. What concerns do you have with Proposed Schedule PPR?

A. I am concerned that Schedule PPR would perpetuate a billing structure that does not allow customer-generators to consume the energy they generate on-site, could be confusing to prospective DG customers, and relies on a valuation methodology that I have shown to be inaccurate. NRLP's proposed Schedule NBR, modified to correct the problems I identify, will be a major step forward from NRLP's existing buy-all-sell-all schedules so I see no good reason to maintain a buy-all-sell-all schedule in addition to Schedule NBR. To the extent that NRLP might intend Schedule PPR as a deterrent to retail rate customers who might otherwise be inclined to "oversize" their solar systems above the cap set by Schedule NBR, there are more effective ways of accomplishing that objective, such as imposing a cost-based charge on over-sized solar systems if those larger systems impose additional, unnecessary costs on the utility.

[32] NRLP response to AV DR 6-1.

III. Residential BFC

A. Summary of NRLP Proposal and the Summarized Response

Q. What is NRLP's proposal for the residential BFC?

A. NRLP proposes to increase the residential BFC from $12.58/month to $14.50/month, an increase of $1.92 (15.3%).[33]

Q. How does NRLP justify the amount of its proposed residential BFC?

A. The specific amount of $14.50/month is not based on a particular calculation or methodology. Rather, NRLP simply states that it is less than its residential fixed costs of $36.00/month.[34] The $36.00/month amount that NRLP quotes is based on the entirety of its proposed distribution revenue requirement for the residential class, as translated into $/customer-month.

Q. Is NRLP's proposed residential BFC cost-based?

A. No. The specific proposed amount is arbitrary, and in fact is higher than the customer-related unit cost indicated by its COSS, which is $13.86/month.

Q. Please explain why NRLP's "fixed" cost of $36.00/month for residential customers is an inappropriate benchmark for consideration of the residential BFC.

A. The costs of NRLP's shared distribution system upstream of a customer's service drop are caused by customer demands, not the number of customers on the system. This is properly reflected in NRLP's COSS. It is

[33] Halley Direct at p. 44.
[34] *Id.*

irrelevant that those demand-related costs are embedded and therefore "fixed". Designing a residential BFC on the basis of a utility's embedded costs irrespective of the cost causation factor associated with those costs is not and has never been an accepted rate design methodology.

Q. Please describe a more proper basis for setting the residential BFC.

A. In order to reflect cost-causation, the BFC should be limited to those costs that are incurred based on the number of customers. There are different schools of thought on how the amount of such customer-related costs should be determined. One widely accepted methodology, often termed the Basic Customer Method, limits residential fixed charges to costs associated with meters and service drops (utility return plus O&M expenses), meter reading expenses, and customer billing expenses. This simple method of isolating customer-related costs is based on the general rationale that customer-specific costs are those costs caused by adding an incremental customer to the system, which generally involves the installation of a meter and service drop, and incremental metering and billing expenses. The primary attraction of this method is that it can be viewed as reflecting the *marginal costs* attributable to customer numbers, which is an important consideration in rate design.

Another method of determining customer-related costs that should be included in the residential BFC is to rely on the cost allocation and classification regime in a utility's cost of service study, such that customer-related costs are defined as those costs that are allocated to individual rate classes based on the number of customers in a class, and potentially a portion of more general utility costs to which one might attribute a customer-related component (e.g., a portion of general overhead costs that cannot be attributed to a specific utility function, or a portion of uncollectibles expense). This may produce a result that is identical to the Basic Customer Method or a different amount. The $13.86/month amount I noted above is based on the amounts that NRLP classifies as customer-related costs in its COSS, which is composed of all the costs that are allocated on the basis of customer numbers and certain others that are allocated based on certain revenue allocators that it represents are tied to customers. The primary attraction of this method is that it aligns the determination of the fixed charge with the cost causation factors accepted in the COSS.

Q. Are there other factors that should be considered in rate design beyond such cost-based calculations?

A. Yes. In practice, and as with all ratemaking decisions, the ultimate determination of an appropriate residential BFC should also consider other generally accepted ratemaking principles, such as gradualism, economic efficiency, utility revenue sufficiency, and avoiding wasteful use of service. The specific calculations described above are useful guideposts with respect to cost-causation, but it is often the case that they are not used in a fully determinative fashion given the need to balance multiple competing objectives. In other words, a certain amount of qualitative judgment is required.

In consideration of those factors, I made a third calculation that uses AV Witness Hoyle's conclusions on a proper capital structure and applies the associated reduction in class revenue requirements exclusively towards reducing the fixed charge. This approach is consistent with creating incentives for energy efficiency improvements by improving the opportunities for customers to substantially reduce their bills and ensures that the revenue requirement reductions will benefit all customers equally, and not create a windfall for high users of electricity. The results of this calculation for the residential and commercial non-demand classes are shown in Table 4 below.

Table 4: Allocation of Revenue Requirement Reduction to BFCs

	Reduction in Revenue Requirement ($)	Reduction Revenue Requirement Per Customer Month ($)	Old Customer Charge ($/month)	New Customer Charge ($/month)
Residential	$151,983	$1.77	$12.58	$10.81
Commercial Non-Demand	$61,427	$3.49	$17.42	$13.93

Q. How do you suggest that the Commission achieve this balance of competing objectives in this case?

A. In sections III(B) and III(C) of my testimony, I present calculations for a residential BFC based on NRLP's COSS, with certain modifications, and the Basic Customer Method. I recommend that the Commission consider those calculations as useful guideposts with due consideration given to other ratemaking objectives. With regards to those other ratemaking objectives, it is also relevant for the Commission to consider that: (1) the residential BFC was doubled in NRLP's last rate case from $6.29/month to its present level of $12.58/month, and (2) increases in fixed charges reduce customers' ability to reduce bills through energy efficiency investments, and because NRLP does not currently offer any significant DSM programs, the retail rate price signal is the sole incentive for customer investments in energy efficiency measures.

B. Calculation of a Residential BFC Using NRLP's Methodology With Limited Adjustments

Q. Please describe your objective in presenting a residential customer-related unit cost calculation based on NRLP's COSS.

A. My objective in preparing this calculation was to preserve NRLP's general methods of attributing cost causation through the cost allocation structure in its COSS, but more accurately reflect the classification of costs in order to render the result more useful as a data point for setting the residential BFC. To that end, I retained the bulk of NRLP's classification regime and only modified the portions that are clearly erroneous. My adjustments are confined to issues of cost classification as they pertain to calculating the residential BFC rather than cost allocation or revenue requirements.

Q. Please summarize how customer-related costs are calculated in NRLP's COSS.

A. Table 5 shows the individual cost components that NRLP classifies as customer-related in its COSS, along with the cost allocation method and their relative contributions to the $13.86/month amount I previously noted.[35]

Table 5: Customer-Related Classification in COSS

Line Ref.	Cost Type	$/Month	Allocation Method
1	Other Operating Income[36]	-$1.09	Total Revenue Excluding Lighting
2	Expense Job & Contract ASU	$0.84	Total Revenue Excluding Lighting
3	Meter Expense	$0.44	Weighted Customer Without Lighting
4	Customer Install Expense	$0.25	Weighted Customer Without Lighting
5	Maintenance Street Lights	$0.00	N/A
6	Maintenance-Meters	$0.66	Weighted Customer Without Lighting
7	Supervision Customer Accounts	$0.39	Weighted Customer With Lighting
8	Meter Reading Expense	$0.01	Customers Excluding Lighting
9	Customer Records & Collections	$6.12	Weighted Customer With Lighting
10	Administration & Other	$4.23	Total O&M Excluding Purchased Power
11	Interest Expense Consumer Deposits	$0.05	Total Revenue
12	Uncollectible Accounts	$0.27	Total Revenue Excluding ASU
13	Regulatory Commission Expense	$0.15	Total Revenue
14	Unrelated Business Income Tax	$1.54	Total Revenue
15	**TOTAL**	**$13.86**	

[35] Based on REH-14 and NRLP response to AV 1-16.
[36] NRLP's COSS includes a customer-related component for non-rate additional revenue, which produces an effective negative amount applied towards customer-related costs.

With the exception of line 10 for “Administration & Other” costs, each line item in Table 3 is classified as exclusively customer-related, including those that are allocated based on some measure of revenue. For the “Administration & Other” category, the customer-related portion corresponds to the portion of total O&M excluding purchased power that is classified as customer-related.

As illustrated in Table 5, the vast majority of customer-related costs in the COSS are for Customer Records and Collections (44.2%), general administration (30.5%) and Income Tax (11.1%), which collectively total 85.8% of customer-related costs.

Q. As it relates to calculating a reasonable residential BFC, do you agree with the customer-related classification regime that NRLP employs in its COSS?

A. No. First, my primary disagreement is that NRLP attributes the entirety of the costs that are allocated using a revenue factor as customer-related. This is not appropriate because revenue from the fixed monthly customer charge accounts for only a portion of the revenue received from a customer class. Therefore, only a portion of a cost that is allocated based on revenue should be considered customer-related. For instance, only a portion of NRLP’s Unrelated Business Income Tax arises due to customer charges, nor are uncollectible expenses comprised exclusively of foregone collections of the fixed customer charge.

Second, I also disagree that expenses for Customer Installations should be considered customer-related. In general, customer installations expenses refer to activities the utility undertakes behind the meter for individual customers. Therefore they are not costs associated with connecting an additional customer to the system or billing that additional customer, nor do they necessarily have a direct relationship to the number of customers on the system.

Third, I disagree with the way NRLP handles expenses and revenue from ASU contracts. As shown in Table 5 NRLP applies a symmetrical classification of ASU contract expenses (Line 2) and the revenue from those activities (included in Line 1 as Other Operating Income), which is intended to fully cover those expenses. However, in the COSS, the ASU contract revenues fall well short of expenses due to timing differences in the incurrence of costs and when the associated revenue is received.[37] That is, a cost incurred during the last month of the test year would not be invoiced until after the test year, resulting in the cost being included in the test year but not the offsetting revenue. For that reason, the COSS produces an implied net "cost" for ASU contracts which equates to $0.28/customer-month for the residential class. In reality there is no such "cost" because the offsetting revenues will eventually be received and the "cost" is simply an

[37] NRLP response to AV 6-12.

artifact of timing differences between the recognition of expenses and revenues.

Finally, although it is true that it is commonplace for the Customer Records and Collections to be considered exclusively customer-related, NRLP's costs in this area appear to be considerably disconnected from customer numbers. I discuss this matter in further detail in Section III(D) of my testimony.

Q. Does NRLP offer an explanation as to why it considers the costs that are allocated based on a revenue factor as exclusively customer-related?

A. In response to data requests regarding the classification of Uncollectable and Regulatory Commission expenses, NRLP stated the following:

> Uncollectible Accounts are expenses NRLP incurs from customers not paying their bills. Therefore, this expense is customer related.[38]
>
> Regulatory Commission Expense is an expense incurred by NRLP for the oversight provided by the North Carolina Utilities Commission for the benefit of NRLP customers. Therefore, this expense is customer related.[39]

Neither of these statements meaningfully explains the cost-causation basis for considering these costs exclusively customer-related. Any given

[38] NRLP response to AV 3-10(d).
[39] NRLP response to AV 3-10(e).

cost NRLP incurs could be explained as arising from the activities that NRLP undertakes to serve customers.

Q. What is your calculation of residential customer-related costs using NRLP's COSS as a base, but incorporating other adjustments?

A. I calculated a residential customer-related unit cost of $11.49/month. This amount is calculated by making the following adjustments to the line items listed in Table 3:

1. Adjust revenue-allocated line items based on the percentage of residential class revenue that is associated with the residential BFC (11.4%), such that each revenue-allocated line item is reduced to 11.4% of the amounts in NRLP's COSS.
2. Eliminate the customer installation costs classification as customer-related.
3. Exclude ASU Contract Expense as a customer-related line item, and symmetrically exclude ASU Contract Revenue from Other Operating Income.
4. Recalculate the customer-related percentage of Administration & Other costs to reflect the above changes.

Table 6 shows the calculated results from these adjustments. Exhibit JRB-3 and my workpapers show further details of the calculations supporting Table 4.

Table 6: Adjusted Customer-Related Classification in COSS

Line Ref.	Cost Type	$/Month
1	Other Operating Income	-$0.06
2	Expense Job & Contract ASU	$0.00
3	Meter Expense	$0.44
4	Customer Install Expense	$0.00
5	Maintenance Street Lights	$0.00
6	Maintenance-Meters	$0.66
7	Supervision Customer Accounts	$0.39
8	Meter Reading Expense	$0.01
9	Customer Records & Collections	$6.12
10	Administration & Other	$3.70
11	Interest Expense Consumer Deposits	$0.01
12	Uncollectible Accounts	$0.03
13	Regulatory Commission Expense	$0.02
14	Unrelated Business Income Tax	$0.17
15	**TOTAL**	**$11.49**

Q. Do you have any further observations regarding the modified BFC shown in Table 4?

A. Yes. My calculation does not make any adjustment to the classification or associated costs for Customer Records and Collection expenses, despite the questionable cost causation basis for these costs that I describe in Section III(D) of my testimony. Nor does it adjust the customer-related classification methodology for General and Administration expenses despite the fact that this general category of costs includes line items for things like consulting expenses, institutional advertising, and injury and damage expenses that have no readily identifiable relationship to customer numbers. Accordingly, my calculation represents an improvement over

NRLP's but likely still overstates the costs that truly vary based on customer numbers and the marginal costs associated with adding a customer to NRLP's system.

C. Calculation of a Residential BFC Using the Basic Customer Method

Q. Please describe your purpose in presenting a residential customer-related unit cost calculation based on the Basic Customer Method.

A. My objective in presenting this calculation is to provide the Commission with a valuable point of comparison for the BFC calculated using NRLP's methodology. The Basic Customer Method of deriving a residential BFC is commonly accepted throughout the nation, and is arguably the single most common method of doing so. I believe my Basic Customer Method analysis will be particularly useful for the Commission's consideration because NRLP's COSS does not readily allow such a calculation, as its calculated customer-related costs do not include ownership costs and depreciation for meters and customer service drops.

Q. Please summarize the results of your calculation of a residential BFC using the Basic Customer Method.

A. Table 7 shows the summation of revenue requirements and the contribution each makes to the residential BFC, leading to a total monthly residential cost of $10.61/month, or $10.38/month if certain revenue-allocated expenses (the Other Expenses line in Table 5) are excluded.

Table 7: Residential BFC - Basic Customer Method

Rate Base Items	Revenue Requirement	$/month charge
Meters	$78,839	$0.92
Services	$16,614	$0.19
SUBTOTAL	*$95,453*	*$1.11*
Depreciation Expense	**Revenue Requirement**	**$/month charge**
Depreciation (Meters)	$94,978	$1.11
Depreciation (Services)	$46,150	$0.54
SUBTOTAL	*$141,128*	*$1.65*
O&M Expenses	**Revenue Requirement**	**$/month charge**
Meter Expense	$37,407	$0.44
Maintenance-Meters	$56,916	$0.66
Meter Reading Expense	$583	$0.01
Supervision Customer Accounts	$33,553	$0.39
Customer Records & Collections	$524,748	$6.12
SUBTOTAL	*$653,207*	*$7.62*
Other Expenses	**Revenue Requirement**	**$/month charge**
Interest Expense Consumer Deposits	$531	$0.01
Uncollectible Accounts	$2,601	$0.03
Regulatory Commission Expense	$1,447	$0.02
Unrelated Business Income Tax	$14,964	$0.17
SUBTOTAL	*$19,544*	*$0.23*
TOTAL	**$909,332**	**$10.61**
TOTAL Excluding Other Expenses	**$889,788**	**$10.38**

Q. Please describe the relevant methodology and assumptions that you used in your calculation.

A. The full derivation can be viewed in Exhibit JRB-4 and my associated workpapers, but the basic assumptions I used are as follows:

- System-wide net plant in service (i.e., rate base) and depreciation amounts were sourced from NRLP's Schedule 6 filing.
- The residential allocation of net meter and service drop net plant was based on total customers (80.4%).
- The utility return on net plant is based on the weighted cost of capital calculated by AV Witness Hoyle (5.39% vs. NRLP's proposed rate of 7.007%).
- The customer-related portion of revenue-allocated expenses (including income taxes) assigns a customer-related portion to the residential allocation based on residential BFC revenue vs. total residential revenue (i.e., the 11.4% proration that I previously discussed).

Q. Do you have any further comments regarding your Basic Customer Method calculation of the residential BFC?

A. Yes, notwithstanding the questions I raise regarding the exclusive classification of customer records and collections expenses described in Section III(D) of my testimony, I have not made any downward adjustment to those amounts in my calculation. In addition, my calculation includes the full cost of NRLP's AMI meters as customer-related costs despite the fact that AMI has a multitude of purposes that relate to the broader operation of the utility system (i.e., demand- and energy-related functions) as opposed to the basic function of measuring customer usage. Consequently, my Basic

Customer Method calculation implicitly overstates the true amount of customer-related costs.

D. NRLP Data Indicates that Costs for Customer Records and Collections Does Not Vary Based on Customer Numbers

Q. How do you recommend that the Commission address the matter of classification of records and collections expenses as it relates to the residential BFC?

A. To be clear, neither of my BFC derivations makes any adjustment to the classification of records and collections expenses as customer-related. Both include the full amount of $6.12/month within the calculated residential BFC. However, I recommend that the Commission consider the issue of whether customer records and collection expenses are *exclusively* customer-related as it weighs the full suite of rate design objectives given the difficulties associated with isolating the cost causation attributes of the different aspects of increasingly complex customer management and billing systems.

Q. Please summarize the types of costs that the general category of Customer Records and Collections includes.

A. Customer Records and Collections basically encompasses the costs associated with billing customers and collecting revenues, including employee labor costs associated with preparing bills, postage, and credit card or banking fees.

Q. Is there a rationale for considering such costs to be exclusively customer-related?

A. Billing of course is an activity that relates to all utility functions insofar as the core purpose is to collect on costs incurred for utility service as a whole, which encompass the provision of energy supply, transmission, and distribution service. Nevertheless, the billing function has traditionally been classified as exclusively customer-related because it is necessary regardless of the amount of a customer's use of the system, and because there is a plausible connection between customer numbers and the costs associated with printing and delivering bills on a monthly basis to each customer, and processing the resulting receipts from those customers. For those reasons, to my knowledge, the classification of billing and collection costs as customer-related has not typically been a matter of significant controversy.

However, there are reasons to question whether that blanket rationale still holds true in a modernized utility system due to the fact that modern billing processes are highly automated and less dependent on manual intervention, modern systems often feature capabilities that extend well beyond the core function of basic billing and collection activities. Such capabilities may include offering different customer billing options, the ability to offer additional services based on the use of AMI systems, and other advanced customer systems that depart from the basic minimum requirements for billing customers. It is reasonable for cost causation purposes for the classification of certain utility system operations to evolve in line with the evolution of the characteristics of these operations.

Q. Is there any evidence in the instant case indicating that NRLP's records and collection expenses are not exclusively attributable to the number of customers it serves?

A. Yes. On a system-wide basis, NRLP's records and collection expenses increased from roughly $471,173 in its 2016 COSS to $779,344 in its 2021 COSS, an increase of $308,171 (65%). Over the same period, the number of customers that NRLP serves increased by only 10.1%, from 8,148 to 8,972.[40] The fact that the increase in expenses and increase in customers are dramatically different certainly suggests that there are important factors other than customer numbers that are driving records and collection costs.

Q. To what factors does NRLP attribute the increases in records and collections costs?

A. NRLP attributes the increase in expenses in this account to new billing software and payroll increases and the offering of new "automated services" such as pre-paid service, and potential future TOU rate offerings. It maintains that the costs should be considered customer-related on the basis that they have a direct correlation to the cost of providing billing to customers.[41]

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[40] Exhibit REH-14.
[41] NRLP response to AV 5-6.

Q. Is this explanation sufficient to explain why the customer records and collections expenses should continue to be considered exclusively customer-related?

A. No. It fails to offer any explanation as to why those costs vary in relation to customer numbers, which is belied by the statistics that I previously cited. That is, it fails to address why billing activities themselves should be considered exclusively customer-related. After all, the need for billing is a consequence of the provision of all utility services so in itself it has no exclusive customer-related characteristic. Rather, the traditional classification of billing costs as customer-related derived from the premise that billing costs vary directly in relation to customer numbers. NRLP's billing expenses, or at least the recent increases, do not appear to have such a linear or direct relationship to customer numbers. In this regard, I am not saying that there is no such relationship, but rather that the relationship does not appear to be exclusive.

Q. How does the increase in customer records and collection expenses affect the residential customer-related unit costs indicated by NRLP's COSS?

A. The 2016 COSS produced a residential monthly customer cost of $4.82/month for these expenses, whereas the 2021 COSS produces a monthly cost of $6.12/month, a difference of $1.30/month.[42] One way to look at this is that the increase in these costs constitutes 68% of NRLP's proposed increase in the residential BFC.

E. The Residential BFC Should Be Reduced

Q. Please summarize the results of the different analyses you have identified for setting the residential BFC.

A. Table 8 shows four different calculations based on the information presented by NRLP, my own calculations, and those of AV Witness Hoyle, as compared to NRLP's proposal.

Table 8: Summary of Residential BFC Calculations

Residential BFC Calculation Basis	Amount ($/customer-month)	Methodology Description
NRLP Proposed	$14.50	Specific amount proposed is arbitrary
NRLP COSS – Uncorrected	$13.86	Full amount of customer-related costs from NRLP COSS
NRLP COSS – Corrected	$11.49	NRLP COSS with certain exclusions and revised customer classification of revenue-allocated costs
Basic Customer Method	$10.61	Limited to costs that vary directly to the number of residential customers
Corrected Revenue & Allocation	$10.81	Application of calculated, reduced class revenue requirement to reduce the residential BFC

Q. What is your recommendation for setting the specific level of the residential BFC?

A. The Commission would be justified in reducing the residential BFC by roughly $2.00/month for reasons of cost causation. There is a compelling

[42] Exhibit REH-14. The residential allocation of customer records and expenses increased by roughly $167,000, which translates to an increase of $1.95/month using current residential customer numbers. This differs from the $1.30/month amount quoted above due to the change in the number of residential customers between the last rate case and the instant proceeding.

argument for such an approach given my analysis of customer-related costs and the fact that NRLP does not presently offer any meaningful DSM programs, leaving the underlying rate structure as the sole source for such incentives.

Furthermore, it is important to consider that my calculations using two alternative methods of calculating a residential BFC were intentionally crafted to be inclusive rather than exclusive in terms of incorporating certain cost categories. For instance, they both maintain customer records and collections expenses as exclusively customer-related, and do not exclude or adjust for other items of questionable inclusion, such as AMI metering as exclusively customer-related, or in the case of the COSS-based method, the imputed customer-related components for general and administrative costs such as institutional advertising or consulting services. In consideration of all of these factors, my view is that the maximum cost-based residential BFC is $10.61/month, consistent with my calculations based on the Basic Customer Method.

IV. Concluding Remarks and Summarized Recommendations

Q. Please summarize your recommendations to the Commission regarding NRLP's proposed Schedules NBR and PPR and the reasons for those recommendations.

A. The Commission should direct NRLP to modify Schedule NBR to: (a) eliminate the SSC component, and (b) and allow indefinite rollover of customer credits for excess energy in place of the proposed calendar year account reset. Both changes are appropriate in light of my analysis of the relative costs and benefits of customer-sited PV in NRLP's service territory, which indicates that Schedule NBR as a retail NEM tariff without any additional charges would provide appropriate, non-discriminatory compensation to participant customers and not create any meaningful cross-subsidies.

I further recommend that the Commission decline to approve NRLP's proposal to establish Schedule PPR because Schedule NBR, with my recommended changes, offers a more suitable structure for a largely common set of eligible customers and its existence as an alternative option could be confusing to prospective DG customers. Furthermore, I have shown that NRLP's calculations of the appropriate compensation rate for Schedule PPR are erroneous as they rely on the same solar value methodology as NRLP used for the proposed SSC component of Schedule NBR.

Q. Please summarize your recommendations to the Commission on setting an appropriate residential BFC.

A. I recommend that the Commission decline to adopt NRLP's proposal to increase the residential BFC by $1.92/month to $14.50/month and instead direct that it be reduced to no more than $10.61/month in order to align it with costs that truly vary in relation to customer numbers, and to provide customers with the opportunity to exercise greater control over their electric bills and provide them with a relatively greater incentive for customer investments in energy efficiency measures. My recommendation is based on my calculations of a cost-based residential BFC using two different methodologies that produce a residential BFC ranging from $10.61/month to $11.49/month, and a separate calculation that uses a revised revenue requirements and allocation approach that produces a residential BFC of $10.81/month. On the balance, a maximum residential BFC of $10.61/month is reasonable considering cost causation and the balancing of other rate design objectives.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-34, SUB 54

DOCKET NO. E-34, SUB 55

DOCKET NO. E-34, SUB 54 In the Matter of Application for General Rate Case DOCKET NO. E-34, SUB 55 In the Matter of Petition of Appalachian State University d/b/a New River Light and Power for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses	**Summary of Testimony of Justin R. Barnes on Behalf of Appalachian Voices**

My name is Justin R. Barnes, and I am the President of EQ Research LLC. I have conducted electric utility industry analyses since 2006, including approximately five years at the North Carolina Solar Center at North Carolina State University and multiple positions at EQ Research. I have submitted expert testimony before the North Carolina Utilities Commission (NCUC or Commission) previously, as well as in multiple other states.

My testimony addresses two topics: (1) New River Light and Power's (NRLP) proposed Schedule NBR "net billing" tariff, including (a) the Standby Supplemental Charge (SSC) proposed as part of that tariff, and (b) a buy-all, sell all DG tariff option in the form of Schedule PPR; and (2) NRLP's proposal to increase the residential basic facilities charge (BFC) from $12.58/month to $14.50/month.

The Commission should approve NRLP's proposed Schedule NBR, with two changes. First, the Commission should eliminate the SSC because my analysis, which corrects errors in NRLP's evaluation, indicates that the value of residential customer-sited solar generation slightly exceeds the residential retail rate. Accordingly, the SSC is unnecessary as a means of protecting non-participants from a cross-subsidy and would overcharge Schedule NBR participants. Specifically, exclusive of NRLP's marginal distribution costs, my analysis indicates that the value of residential customer-sited generation is in the range of 11.8 – 13.7 cents/kWh compared to a proposed residential retail rate of roughly 14.8 cents/kWh. I further estimated that the avoided distribution costs associated with residential solar range from 4.9 – 5.4 cents/kWh, which results in the overall solar value exceeding the residential retail rate by at least 15% under each of five different solar capacity contribution scenarios that I examined.

I identified six main deficiencies in NRLP's calculation of its proposed SSC. First, and foremost, NRLP's evaluation of the costs and benefits of customer-sited solar makes a basic methodological error by basing the calculation of avoided cost benefits for demand-related cost elements on the volumetric residential retail rate, rather than the demand unit costs that produce the retail rate. This is incorrect because the retail rate is a flat rate that represents the cost of peak demands averaged across all hours and customer demand, and as a consequence fails to reflect the fact that NRLP's costs are incurred based on customer demand during a limited number of peak hours. This causes NRLP's analysis to understate the cost savings associated with customer-sited solar and its contributions to reducing demand during peak hours, which translates directly into the purported need for, and proposed amount of, the proposed SSC. Ultimately, NRLP's methodology is inconsistent with cost causation and a proper analysis of the benefits of customer-sited solar.

Beyond this foundational error, I identified five additional problems with the utility's analysis and the proposed SSC: (1) NRLP's analysis of solar contribution to periods of peak demand relied on solar production data that contains large amounts of missing data, and uses an inaccurate methodology to fill in those gaps; (2) NRLP failed to include reduced distribution system loading and accompanying avoided distribution capacity benefits in its evaluation on the incorrect grounds that its distribution costs are fixed, which ignores the reality that all utilities have marginal distribution costs and all types of costs are marginal over the long-term; (3) Schedule NBR will be available to non-residential customers, but NRLP's analysis of costs and benefits was limited to, and can only be applied to, residential customers; (4) NRLP proposes to base the SSC on the AC nameplate capacity of the customer's inverter rather than the system design capacity, which conflicts with how it calculated the proposed SSC; and (5) NRLP's SSC calculation implicitly assumes that customers would be able to fully utilize all system production to offset retail purchases from NRLP as part of the "cost" side of its evaluation of customer-sited PV costs and benefits, when in fact NRLP proposes to zero-out accrued excess generation on January 1 of each year. NRLP addressed deficiencies (3) and (5) in supplemental filings.

Second, the Commission should modify the proposed Schedule NBR to allow indefinite carryover of accrued credits, or in the alternative, allow a customer to choose their annual period, instead of requiring annual forfeiture of accrued credits on January 1 of each year. This change would allow customers to size a system to fully offset their annual on-site energy consumption, and would provide a simple and effective deterrent against oversizing. In addition, because I find that the benefits of customer-sited solar are greater than the residential retail rate, there is no need to eliminate credits in response to cross-subsidization concerns.

The Commission should decline to approve NRLP's proposed Schedule PPR for three reasons. First, it prevents qualifying customers from enjoying the full benefit of their solar systems by prohibiting them from consuming the energy they generate on-site. Second, it bases compensation on an inaccurate methodology for determining the avoided costs of customer-sited PV, as I previously discussed. Finally, it could be confusing for customers because its eligibility requirements significantly overlap with those for Schedule NBR.

The Commission should deny NRLP's proposal to increase the residential BFC to $14.50/month, and direct NRLP to reduce the residential BFC to no more than $10.61/month. NRLP's justification for its proposed BFC amount is that $14.50/month is less than its residential fixed costs of $36.00/month, an amount based on the entirety of its proposed distribution revenue requirement for the residential class, as translated into $/customer-month. But the BFC should be limited to costs that are incurred based on the number of customers and such customer-related costs are only a portion of NRLP's distribution costs. Rather, the costs of NRLP's shared distribution system upstream of a customer's service drop are caused by customer demands, not the number of customers on the system. It is inappropriate to include those demand-related costs in the BFC, as doing so ignores the causes of those costs, and consequently sends an inaccurate price signal to customers. I calculated a residential BFC of $10.61/month using what is commonly referred to as the "Basic Customer Method" under which customer-related costs are limited to the costs of meters, service drops, and customer service and billing expenses. This amount is reduced to $10.38/month if certain additional expenses that NRLP classifies as customer-related in its cost of service study are excluded.

MR. JIMINEZ: I would also move that we move his live supplemental testimony into the record.

COMMISSIONER KEMERAIT: Your motion is allowed.

And with that, we are gonna take our afternoon break, and let's be back at 3:50. We'll take a short, 10-minute break.

(At this time, a recess was taken from 3:41 p.m. to 3:51 p.m.)

COMMISSIONER KEMERAIT: Okay. We'll go ahead and get started and go back on the record.

MR. JIMINEZ: Madam Chair -- rather, Commissioner Kemerait, I think we covered the bases. The witness is available for cross examination and questions from the Commission.

COMMISSIONER KEMERAIT: And, Ms. LaPlaca, you have not reserved any cross examination time. Is there -- do you have a short cross examination that you would like to do? You did not reserve any time.

MS. LaPLACA: Yes, ma'am, I would. I do apologize. I'll keep it short.

COMMISSIONER KEMERAIT: Okay. Please

proceed.

CROSS EXAMINATION BY MS. LaPLACA:

Q. Mr. Barnes, you stated in your testimony that the cost of solar is very close to the cost of retail -- the new retail rate, which I think is 14.8 cents a kilowatt hour, if you include the avoided distribution capacity costs.

Could you walk us through that, please?

A. Well, I think what I -- what I calculated was the value of customer-sided solar as approximately the same as the retail rate. And in my testimony, there is a table in which I -- I basically conducted several different effective capacity contribution scenarios for solar, as well as using some -- some of the Company's data to define effective solar capacity contribution.

And in those calculations, without the -- without any avoided distribution value, on average, based on residential class billing determinants, the value of customer-sided generation comes out to about 80 percent of the retail rate.

If you layer in some additional distribution value, just based on unit costs associated with the Company's imbedded distribution costs, that's when you get a number that, you know, potentially exceeds the residential retail rate.

I mean, as I emphasized in my testimony, those imbedded costs are not marginal costs, and the remainder of my analysis is based on marginal cost. I had to use imbedded cost, simply because I didn't have any marginal cost information available. But I think what it demonstrates is that, even at a substantial discount to the Company's imbedded distribution costs, the value of customer-sided DG is the same as retail rate.

Q. And, Mr. Barnes, can you give us some numbers on that? I think one was, like, 11.1 to something cents a kilowatt hour, and then the avoided distribution was, like, 1.1?

A. If I can find my table, I can relay the specific numbers.

Q. Okay.

A. I don't remember exactly what page it's on.

Q. I think I have it right here. It's your testimony direct, page 4.

A. Okay. Yeah.

Q. Lines 5, 6 to 8. 5, 6, 7, 8.

A. Okay. I'm looking at Table 3, page 28, and so the range that I see, based on different solar system orientations, and resulting in different effective solar capacity contributions, is 11.8 to 12.8. That's without any distribution value. And then with distribution value, anywhere from 17.1 cents per kilowatt hour, up to 18.9 percent -- 18.9 cents per kilowatt hour.

Again, that's depending on how you calculate effective solar capacity. Basically, the ability of solar to avoid costs, and that depends on the production profile of the solar system and what direction it's oriented in relation to times of coincident peaks on New River Light and Power System.

Q. I have no further questions. Thank you.

MS. LaPLACA: Thank you, Commissioner.

MR. FELLING: No questions from Public Staff.

COMMISSIONER KEMERAIT: Questions from New River?

MR. DROOZ: Please.

CROSS EXAMINATION BY MR. DROOZ:

Q. Mr. Barnes, just on that last point, as I look on that table on page 28, you also had mentioned in your testimony some missing solar data in the calculations performed by the New River witness; is

that right?
A. That's right. There was -- I believe, there was approximately 30 percent of daylight hours missing from the Company's solar dataset.
Q. 30 percent within a certain time frame, right?
A. Well, within the solar production window, which is kind of what matters.
Q. Okay. And so Mr. Halley had -- in this question, he had used, to my understanding, is actual solar production data from the AMI metering. And then for the missing parts, he had interpolated based on the actual data that was in -- nearby in time.
Is that your understanding as well?
A. Yeah. He interpolated it, but he did it wrong.
Q. Now, when you did your analysis, you actually didn't -- you did not use actual data; you used modeled data; is that right?
A. That's right.
Q. Okay.
A. I used PVWatts, and the reason I used different solar system orientations was because, of course, not all systems are gonna be oriented directly

south. Typically, you try to orient them in a southward direction. So my -- the range of solar capacity contributions that I calculated and that range of ultimate solar values is based on, basically, a range from southeast to southwest, in terms was solar system orientation.

Q. And that's not actual data, that's modeled?

A. It's -- well, yeah. It's a hypothetical PVWatts solar production profile.

Q. Thank you. I wanted to ask you some questions about -- use the minimum system method in the cost of service study versus the basic customer method, and I believe this is a subject you're familiar with from prior cases as well; is that correct?

A. Yes, it is.

Q. Okay. And do you understand that Mr. Halley used the various minimum system method in his cost allocation analysis?

A. That's something I'd actually like to clarify, because he -- I believe, in his rebuttal, he said he used a modified minimum system method.

Q. Right.

A. A minimum system analysis is an actual analysis of the minimum size system required to support basically any demand, or, you know, the typical, say, average residential customer.

As far as I can tell, Mr. Halley did not perform any such analysis. He simply calculated the -- his modified -- his modified minimum system analysis was just assuming that all class costs of -- all distribution costs were customer related costs. That was his modification. I don't -- I don't consider it an analysis.

Q. And that modification actually is more favorable towards your position than if he had done the traditional minimum system method, isn't it? Low to less cost on the customers?

A. I would not imagine -- I would not imagine it would be, because a typical minimum system method would only classify a portion of the distribution system as customer-related, whereas, at least as I understand Mr. Halley's numbers, his $36 a month is based on the entirety of the Company's distribution system. So not a portion.

Q. Okay. Are you opposed to use of the minimum system method?

A. In particular, I am opposed to it for the purpose of setting basic facilities charges. I have not always -- I have not necessarily always taken the position that there can't be some customer-related component when it comes to cost allocations.

Q. And in this case, you provided three alternative methods for calculating the basic facilities charge; is that correct?

A. Yeah, I did.

Q. And the first method, not that there is any particular order, is the basic customer method?

A. That was -- yes, that was one method I used.

Q. And your $10.61 figure is based on that basic customer method?

A. Right. That's based on the costs of metering and service drops, depreciation expenses, return on meters and -- return on meter -- return on meter and service drop plant, as well as, essentially, like, billing and administrative expenses.

Q. Do you know if the basic customer method is one of the methods that's in the National Association of Regulatory Utility Commissioners, or NARUC, Electric Utility Cost Allocation Manual?

A. It's not, and that's a cost allocation manual, not a method of -- not a description of how to set basic facilities charges.

I will note that, in the past, although I did not do so in this case, there was a letter submitted by several commissions to NARUC, after they published that particular manual, voicing disappointment and displeasure about the fact that the basic customer method had been omitted in the final draft. I believe that was signed by commissioners in Washington and Arizona at a minimum. I would be happy to provide that to the Commission if they would like me -- if they would like to see that.

Q. That was not signed by North Carolina's Commissioners, was it?

A. Not that I recall, no.

Q. Okay. So you had mentioned this distinction between cost allocation and setting a basic facilities cost charge, which is, I guess you could say, rate design. Is that -- did I have that correct?

A. Yeah, rate design and cost allocation do not necessarily have to be identical to one another.

Q. Does cost allocation essentially mean cost causation?

A. It's one reflection of cost causation. Typically -- typically, about the best we can do with the fact that we possess incomplete data and, you know, it's very complicated to assign specific costs of service, you know, for large interconnected systems with lots of unique customers.

Q. Right. It's fair to say there is no single perfect cost-of-service methodology, right?

A. Yeah, there is not.

Q. So getting back to this cost allocation versus rate design, would you agree that cost causation is a very important part of rate design?

A. Yeah, it is.

Q. Okay. Your second method -- and you may have to help me on this -- as I understand, it's a basic facilities charge on some modifications you made to customer-related costs that New River had included in its cost of service study; is that correct?

A. Yeah, that's correct. It was basically -- there is a column in the Company's cost of service study where a -- an expense has been designated as customer-related; there is a little seat next to it. And then those costs are sum to a quote, unquote, customer-related revenue requirement, at one portion of the cost-of-service study.

Q. Are some of the costs that you recommend removing demand-related costs?

A. No. The adjustments that I made to -- in that derivation, were primarily -- the Company had for several -- several of those line items, among them, the unrelated business income tax line, as well as regulatory Commission expense. A few of these, kind of, like, general expenses of the utility had allocated those using a revenue factor.

In other words, the allocation to the residential class was based on basically residential revenue was a portion of the utility's overall revenue. But the Company had classified all of those costs exclusively as customer-related.

So the primary modification that I made in, I think what I referred to as my New River Light and Power Modified Cost-of-Service Analysis, was that I -- I essentially said that, well, not all revenue -- or not all of the Company's revenue is associated with the customer charge; and, therefore, only a portion of a cost that is allocated based on a revenue factor should be considered customer-related, about 10 percent.

So the modification -- the main modification I made was to basically prorate that by down to about 10 percent, rather than have it be exclusively, kind of, logged as customer-related.

Q. And so the costs that you removed from the basic facilities charge, which is a fixed monthly charge to customers, would then be recovered in the kWh volumetric charge?

A. Yes. Presumably it would.

Q. And are all those costs directly proportional to kWh usage?

A. No. But nor are they directly proportional to the number of customers. And one of the best quotes I've ever seen from a ratemaking expert, from John Bonbright, who urges us not to let the category of customer-related costs become a dumping ground for all costs that we cannot plausibly attribute to another cost factor.

Q. Does that mean the volumetric should become the dumping ground?

A. Volumetric has historically been, in part, dumping ground, because of the basis we're not -- you know, when we sign up for a utility, what are we asking for? Electricity.

Q. Okay. The third method, as I understand your testimony, is you take the dollar reduction to revenue requirement that would result from Appalachian Voices' cost-of-capital recommendation, and you use that -- you subtract that entirely from the basic facilities charge, rather than having any of that lower the volumetric rate; is that correct?

A. Yeah, that's correct.

Q. Okay. And that has nothing to do with cost causation, that's just a way of lowering the basic facility charge to reduce the basic facility charge, right?

A. It has the objective of placing a priority on supporting customer investments and energy efficiency, which I think is particularly compelling, given that the Company has been a bit resistant to offering DSM programs; and, therefore, the price signal sent by volumetric rate, you know, could be a reasonable compromise for providing that kind of incentive where no other incentive exists. It's a policy. It's a policy decision.

Q. Okay. Would it be a little bit clearer, policy-wise, if you want to insist on EE programs, just to mandate them and fund them, instead of trying to create that and send them through the backdoor by reducing the basic facility charge?

A. Well, I mean, the basic facilities charge that derives from that estimate is actually higher than the basic facilities charge that I recommended based on the basic customer method. I think the basic customer method is the most methodically sound way to arrive at a basic facilities charge. So, you know, that was another -- it's another example of the fact that none of these numbers are necessarily as precise as they look on a piece of paper, because cost-of-service analyses are not precise in that way either. So -- but the three numbers, I think, present a very reasonable range for the Commission.

Q. Did you oppose use of the minimum system method in the Duke Energy Carolinas case, Docket E-7, Sub 1146 that was decided in 2018?

A. If I remember correctly, I opposed it for the --

Q. For the use of the facility?

A. Yeah. For, like, taking that number and then applying it directly to calculate the basic facilities charge.

MR. DROOZ: I'd like to hand out, if I may, a collection of three cross examination exhibits here. The first will be an excerpt, because the Commission's Order in Sub 1146 is 400-and-some pages. I have excerpted the part that is specifically titled "minimum system method," and we would ask that be marked -- I'm not sure what our convention is, because I don't have the label in front of me.

COMMISSIONER KEMERAIT: We'll mark it for identification purposes as New River Cross Examination Barnes Direct Exhibit 1.

MR. DROOZ: Thank you.

(New River Cross Examination Barnes Direct Exhibit 1 was marked for identification.)

MR. DROOZ: And then I have a second cross examination exhibit I would like to have marked for identification, which consists of the report of the Public Staff filed with the Commission in E-100, Sub 162 on March 28, 2019.

COMMISSIONER KEMERAIT: Mr. Drooz, we'll have that exhibit marked as New River Cross Examination Barnes Direct Exhibit Number 2.

(New River Cross Examination Barnes Direct Exhibit 2 was marked for identification.)

MR. DROOZ: And finally, we are handing out a third cross examination exhibit that is the responses of New River Light and Power to Appalachian Voices' eighth set of written discovery requests. And that would be New River Light and Power Barnes Cross Examination Exhibit Number 3, I believe.

COMMISSIONER KEMERAIT: So, Mr. Drooz, the responses -- what's been marked -- described as responses of New River Light and Power to Appalachian Voices' eighth set of written discovery responses, is that the one you are referring to now?

MR. DROOZ: Yes.

COMMISSIONER KEMERAIT: That would be marked as New River Cross Examination Barnes Direct Exhibit Number 3.

(New River Cross Examination Barnes Direct Exhibit 3 was marked for identification.)

COMMISSIONER KEMERAIT: And, Mr. Drooz, I think there is some confusion among the Commissioners about which exhibit is Exhibit Number 1 and which is Exhibit Number 2. So if you could clarify which is 1 and which is 2.

MR. DROOZ: Exhibit Number 1 should be

the excerpt from the E-7, Sub 1146 Order of the Commission. The Order issued June 22, 2018.

Number 2 -- and I did these chronologically -- is the report of the Public Staff, E-100, Sub 162 that was issued March 28, 2019.

COMMISSIONER KEMERAIT: Thank you.

MR. DROOZ: So the numbers are in chronological order.

COMMISSIONER KEMERAIT: Thank you.

Q. So do you have copies?

A. No, I was not furnished a copy.

Q. Okay. Well, that's important, and I want to give you a second to take a look.

A. (Witness peruses document.)

So which is which?

(Pause.)

MR. STYERS: Mr. Drooz, the witness is -- which one is 1, 2, and 3.

Q. So Number 1 is the excerpt from E-7, Sub 1146. Number 2 is the E-100, Sub 162 document. And then the data responses are Number 3.

Okay. So we'll start with Number 1. And you'll notice, in the first paragraph, where it starts,

"minimum system," that, the Company, which refers to Duke Energy Carolinas, used minimum system study to allocate distribution cost among customer classes. It goes on to say, NCSEA witness Barnes objects to the use of minimum system study to allocate costs to customers; is that correct?
A. That's what the Order said, yes.
Q. And did you, in fact, object to use of the minimum system study for that purpose?
A. I -- I cannot recall whether I objected only to the use for defining the basic facilities charge, or whether I objected to both its use for cost allocation and designing the basic facilities charge. I don't have a copy of that testimony. Like, I'm not positive that, you know, maybe there was something lost in translation in the Commission's Order.
Q. Okay. Let's turn to what's numbered at page 87 at the top. That would be, I think, the fourth page in this exhibit. And you'll see in the second full paragraph, the Commission recognizes the importance of addressing issues, such as those that you discussed in that case, in that first sentence in the second paragraph, right?
A. (No verbal response.)

Q. And if you follow down, does it also indicate, the Commission directs the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of the minimum system, et cetera, and the Public Staff shall submit a report on its findings to the Commission? Is that correct?

A. Yeah. I recall that when it was issued and I am reading it now.

Q. And then in terms of how they resolve the issue in that case, will you read the last paragraph in this exhibit into the record, please?

A. The -- you mean the third paragraph on --

Q. Yeah, the one that starts "upon consideration?"

A. Upon consideration of all the evidence in this docket, including the stipulation, the Commission approves DEC's use of the minimum system methodology for cost allocation in this proceeding. The Commission places significant weight on the testimony of Company witness Hagerty, regarding the Company's long history of the employing the minimum system method and this method's alignment with cost causation principles. The Commission finds that the Company's use of the minimum system method for cost allocation in this proceeding is just and reasonable to all parties and in light of all of the evidence presented.

Q. And do you have any information that would contradict the idea that the minimum system method -- there's been a long history of its use by utilities in North Carolina, for purposes of cost allocation?

A. You know, I'm aware that it was used, certainly, at least in the rate case prior to this one, because I seem to recall reviewing, like, the calculation prior to that time.

Q. And was that used to inform the decision on basic facility charges in those cases?

A. I presume it probably was; but I don't specifically know.

Q. Okay. If you'll turn to the second cross examination exhibit, the one from Docket Number E-100, Sub 162. And I will submit to you and the Commission that this exhibit contains the Public Staff's report without their appendices, because again, that would have been another 50 pages of numbers that I don't think would have been productive, but it's on file with the Commission should anyone want to review that.

And will you turn to page -- what's numbered as page 15 in this exhibit?

A. (Witness complies.)

Q. And you'll see a highlighted sentence down there. Could you read that into the record, please?

A. The Public Staff has traditionally advocated a position that supported a basic customer charge based on the utility's MSM. While recognizing that full movement would likely result in rate shock from customers, particularly low-income and low-usage customers.

Q. And could you read the sentence at the bottom of page 16 and top of page 17?

A. After I reviewed, the Public Staff believes that the use of the MSM by electric utilities for the purpose of classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge. While not precise, MSM is a logical methodology for classifying costs of a distribution system as demand or customer related.

Q. So when you came up with a basic facility charge in this case that you recommended at $10.61, based -- excuse me -- based on the basic customer method, that's really something of a departure, methodologically, from what has been used previously and what has been suggested as the basis for the maximum BFC in the Public Staff's report, isn't it?

A. Public Staff and I have a clear disagreement on the proper methodology. I think that -- I think my words speak for themselves on that front and theirs do their own.

Q. I understand. If you'll turn to the last -- the third exhibit here, which is the response to data request. And turn to Item 8-1, which is on the third page.

A. I'm there.

Q. And part B there says, Please identify specific Commission decisions that support witness Halley's statement. My approach is more in line with past North Carolina utility regulation than the approach offered by Mr. Barnes.

And in the response, you'll see citations to some cases, and if you turn to the next page, page 4, there's a reference to Docket Number E-100, Sub 180, the Commission Order of March 23, 2023; do you see that?

A. I do.

Q. Okay. And do you know what E-100, Sub 180 was?

A. The Duke solar choice docket.

Q. That's Duke's net metering docket, right?

A. Yeah. Their residential successor.

Q. Okay. And this is not the original, but emphasis I added.

Could you read from the footnote that's quoted there, the bold underlined statement?

A. The Commission has, to date, accepted Duke's cost-of-service studies and set the basic facilities charge at levels that are less than Duke's cost-of-service studies show are necessary for full recovery of its fixed cost of service.

Q. And that's essentially what New River's recommending to the Commission in this case, isn't it? They used a minimum system study methodology and recommend a basic facility charge that's actually less than the fixed cost that their study suggested.

A. I don't disagree that New River Light and Power's proposal of 1450 is, you know, I think fairly well in agreement with that particular passage. It -- I disagree with it, from the standpoint of an expert.

Q. Right. And that's what experts do. Thank you. That's all my questions.

COMMISSIONER KEMERAIT: Redirect?

MR. JIMINEZ: Yes, Commissioner. Thank you.

REDIRECT EXAMINATION BY MR. JIMINEZ:

Q. So, Mr. Barnes, going back to beginning of the conversation you had with Counsel Drooz, at the very start you were discussing the missing solar data in witness Halley's analysis, and you described how you used model data from PVWatts.

Why is PVWatts better than witness Halley's approach?

A. You're faced with a question of relying on data which you know to be incomplete; which -- you know, you're missing 30 percent of values for daylight hours, which is one thing. Do you necessarily trust the rest of the data because you're missing so much, and do you have a reasonable methodology to fill that data in? You know, those are questions that were percolating in my mind as I was, kind of, evaluating what to do with this.

You know, there is some level of imprecision associated with using hypothetical solar production profiles, because they don't necessarily represent, you know, the average of all customers, whereas, presumably, a full dataset of the type Mr. Halley presented, if it was full, would, you know, provide actual information.

I think what I conclude from my analysis is that, when I run the numbers using my hypothetical scenarios, run the numbers using Company witness Halley's unadjusted scenarios, and then run those same numbers again after correcting some other errors in Company witness Halley's methodology, the end result all ends up being fairly close to the same. Which leads me to believe that there is nothing wrong with my use of a hypothetical solar production profile as reasonably representative of what customer systems in New River Light and Power's service territory look like from a, you know, production shake standpoint.

Q. Okay. Moving to your discussion of energy efficiency. Counsel asked you some of the effective -- wouldn't it be easier to mandate energy efficiency than to put fixed charges into the volumetric rate and encourage energy efficiency that way.

If a utility really wanted to encourage energy efficiency, couldn't it do both?

A. Sure. You know, it's not -- you know, the volumetric rate is one arrow in the quiver. Time varying rates could be another arrow in the quiver, with respect to supporting demand reduction conservation. Proactive and targeted demand response programs are another way of addressing the same -- ideally, you would use them all. But when forced to rely on, you know, a limited scope, you know, I kind of use the tools at my disposal to offer one suggested approach.

Q. Okay. So you also had this, sort of, deep dive into previous filings with Counsel. I want to bring you back to what I hope is Exhibit 2, the report of the Public Staff. And if you'll look on page 17. So I wrote down the words -- I believe this is right. You said there was a disagreement between you and the Public Staff on the, sort of, merits of the minimum system method and ways to set a basic -- a facilities charge.

On 17, beginning right after the highlighting, at the word "however," could you read that sentence and the following bullet, please?

A. The minimum amount recovered in the fixed charge for any rate class should be the amount determined by the basic customer method, which reflects the customer meter service dropped and any other facilities uniquely attributable to specific customers that are not already recovered through extra facilities charges.

Q. Thank you. Okay. One more question on this exhibit.

Recognizing you might not have reviewed this in its entirety at any point, in what you have seen today, did you see the Public Staff say anywhere that it's inappropriate to use the basic customer method?

A. I guess the best I can say is I don't recall the Commission, in any rate case order, ever establishing a specific methodology with which to set the basic -- the residential basic facilities charges.

Some of the -- some of the passages which Mr. Drooz asked me to read were focused primarily on cost allocation rather than rate design. Plausibly, there is a specific finding, you know, saying this is the way to set the BFC that I'm not aware of, but I don't recall -- I don't recall that in -- from having read past Commission orders.

Q. Or that it's prohibited?

A. As far as, like, it's prohibited to use the basic customer method as a method of setting the basic facilities charge?

Q. Right?

A. No, I'm not aware of any limitation that says it's prohibited.

MR. JIMINEZ: Okay, that's all for me. Thank you.

COMMISSIONER KEMERAIT: Mr. Barnes, I have a couple of questions for you.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q. Following up on your attorney's last questions, in regard to the basic customer method, you just testified that you were not aware of any Commission order that says that use of the basic customer method is prohibited.

Can you cite us or point us in the direction of any utilities that use that or the Commission that has approved the basic customer method for either cost allocation or determining the residential basic facilities charge?

A. I can certainly do so in, kind of, cited format in a post-hearing request, if you would like. It is information I have included in testimony in -- on this issue in the past, I just happened to have not done so here.

Orally, the places where the basic customer method are used exclusively: the state of Texas, the state of Maryland, the state of Massachusetts. There was a recent finding in New Hampshire that was in agreement with that. Historically, it's been used in West Virginia.

I tried to think of -- those are the ones I'm, kind of, coming up with off the top of my head. My recollection is that there are approximately, you know, 20 to 25 states that use the basic customer method within -- with a certain amount of variation in between exactly how they make the calculations.

Q. And I think what I'm interested in is, in North Carolina -- if you have any examples of the basic customer method in North Carolina, then you could provide that in a late-filed exhibit. Not in other jurisdictions, but in North Carolina, if you can cite to anything specific for orders or for utilities.

A. I actually I do not recall any in North Carolina.

Q. Okay. Well, then a late-filed exhibit will not be necessary, unless you come up with something and you would like to provide them, we will accept a late-filed exhibit.

And then, starting on page 4 of your testimony, you've provided a recommendation that New River's proposed schedule NBR be modified to eliminate to the annual forfeiture of the net excess credits on an annual basis on January 1st. And then I think your -- kind of your alternative position is that -- is that, if that is not allowed by the Commission, that the customer be able to choose their annual period, as opposed to relying upon the certain date of January 1st.

Can you provide some information or talk about whether having the choice about what that annual period would be, would that be an administrative burden to New River Light and Power, or how would that work, from a practical standpoint?

A. Well, I mean, typically the way it's been practiced in other jurisdictions, where there wasn't a set date and a customer could choose it, is that the customer would just pick a date at the time of their interconnection application, and it was a one-time election that they could never change. And that would be logged with the system, and, I mean, as far I know, as long as you can bill monthly, it has not been inherently problematic anywhere else, so.

Q. And then you also state -- this is also, I believe, on pages 4 and 5 -- that the indefinite rollover would provide a deterrent against oversizing of the systems.

Can you provide a little bit better or more explanation about why you think that would be a sufficient deterrent?

A. Well, so, to the extent, if you're using a definite rollover, that basically means that there is no -- there is never a reset. You're never, you know, kind of permitted to cash out your account and, you know, take any form of monetary payment at all.

So if you install a system that produces 50 percent more than what you need to supply your on-site needs on an annual basis, all you're gonna do is just continue to accumulate credits that you can never redeem.

And so that's the kind of inherent incentive that indefinite rollover provides, from the standpoint of system sizing. It helps remove what has sometimes been a level of contention when customers are attempting to document what system size is necessary to support their expected electricity usage, and don't have a full history or have missing months or just moved into a house or going to have, like, a new load, like a new heating system or a new AC system or new EV.

Like there are a lot of, kind of -- there are a lot of reasons why an annual historic average may not reflect future usage, but as long as you're using indefinite rollover, you are, kind of, just putting the onus on the customer to, well, if you -- if you -- you're giving away free -- you're giving away free electricity to the utility if you oversize it intentionally, so just don't do that.

Q. And that would be, kind of, the same situation, if there was that reset on an annual basis as well, unless I'm not understanding your testimony. Wouldn't that also work as a deterrent as well?

A. Well, yeah, an annual reset, kind of, inherently does that as well. My concern is that one on January 1st would be potentially harmful to some consumers by causing them to forfeit -- you know, by causing them to never be able to fully offset their electric consumption, because it's not as though -- you know, it's not as though their electricity consumption is consistent from month to month.

So a January 1 reset, they may have been saving 500 kilowatt hours that they would have otherwise used in January and February; but instead, they are not able to do that. If they are able to choose their date, that's an improvement. It doesn't serve to, kind of, avoid the issue of sizing disputes though.

Q. Okay. Thank you.

COMMISSIONER KEMERAIT: So I'll look to my fellow Commissioners to see if they have any questions.

Chair Mitchell?

Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Barnes, only one question really on the basic facilities charge -- fixed monthly charge, I'll call it, because it's easier to keep the naming convention separate. The fixed monthly charge.

I have the exhibits that we offered up in 1146 that show the use of the different methodologies among the various states at that point in time. And I would actually be interested in seeing, as a late-filed exhibit, an updated list to see what may have changed since 2017, in terms of the use of different methods for establishing the monthly fixed charge.

So if you have a current version of what was offered as an exhibit in 1146, I would be interested in seeing the current version as a late-filed exhibit.

A. Okay. I don't have an absolutely current version, but I definitely have an updated version, which might be up to date as of, like, 2022.

MR. DROOZ: And I don't know what exhibits that refers to in 1146. I don't know if you have something more specific.

COMMISSIONER CLODFELTER: Well, I don't have the exhibit number off my read right now, but it's in the record in the case.

I will commit to, through the appropriate channel -- probably through Commission counsel to you -- get you the exhibit number that references out of the Docket from 1146.

MR. DROOZ: Thank you.

COMMISSIONER CLODFELTER: It's there. Mr. Barnes offered it. I recall the testimony very well.

Q. You were asked a lot of questions. I just have to ask this so the room is not silent on the point. I mean, it's sort of -- you answered a lot of questions about whether the Commission's ruled this way or ruled that way or has prohibited the use of the basic customer method or has endorsed it here or there.

Are you aware that the legislature has actually spoken to this question since 2017?

A. I recall the passage of a section of North Carolina law that says -- requires the use of minimum system for cost allocation and it says does not necessarily need to be used for the purpose of setting the --

Q. I'm not gonna ask you to read the law, interpret the law. There's too much of that that goes on around here. Just didn't want the room to be silent thinking the only thing we knew about was Commission decisions. Thank you, sir.

I'm gonna move to the NBR, and I have some questions for you. I'm gonna ask a lot of these same questions of Mr. Halley and maybe one or two from Mr. Miller, but this is my only shot at you, so I have to ask them of you too, to see what your answers are.

I'm gonna read you something. You don't need to have it in front of you. I'm gonna read it from they rebuttal testimony of Mr. Miller.

Mr. Miller says, and I quote, from page 6 beginning at line 12 of his testimony, he says: "NRLP has adjusted the amount of renewable energy utilized in its development of Schedule NBR and Schedule PPR to recognize the portions of the hourly load data missing from its initial analysis. This revision is shown in Miller Rebuttal Exhibit Number 1."

I call that -- this is the missing data issue that it speaks to.

Have you reviewed Miller rebuttal Exhibit Number 1?

A. I recall reading that passage, but I don't recall the exhibit, itself.

Q. So you couldn't really talk to me about the exhibit then, if you don't even recall it.

The question I was gonna ask you was, does the Rebuttal Exhibit Number 1 supply actual data that was previously missing or is it interpolated, according to some method?

A. As far as -- I don't know how you would, kind of, reconstitute actual data if you've already lost it. I guess I can't say specifically, but I find it doubtful.

Q. Well, as I say, I'm gonna ask Mr. Halley these questions, too. But I want to know what you know, because this is, again, your chance to tell me. The quote, unquote, missing data, is it just gone, doesn't exist, or was it not captured in the first place, or was it lost along the way somewhere? What is your understanding from your investigation of the matter?

A. I guess I don't know where it went. All I can say is that, like, the duration of the, kind of, missing data might be an hour on this day and then 17 hours on the next day and then, you know.

So what happened to it? Was it not recorded or was it, you know, lost somewhere else? I just don't know.

Q. So you told me all you can right now about the missing data issue?

A. Yeah, I mean --

Q. Okay. That's fair. That's fair.

I want to understand something else about the NBR rider here.

Have you -- in your view of NLRP's [sic] customer base, have you looked at the customer set that has currently solar PV and installations?

A. That's about 14 residential customers.

Q. About 14 total?

A. Yeah. That was the -- that was the sample set for that dataset of PV production data. As far as

I know, that's all of their DG customers.

Q. Those are residential. Are there any commercial customers?

A. I -- I don't think there are any commercial. I recall that, for the purposes of calculating those -- of witness Halley's calculations, he excluded, I think, one App State windmill from the dataset.

Q. Because App State wouldn't be an NBR --

A. Exactly.

Q. -- eligible customer anyway?

A. Yeah. So if I remember correctly, there were 15 customers in the initial sample, and then for the purposes of his calculation, he removed this one customer, which is this App State windmill.

Q. Again, I'm going to ask Mr. Halley this, so he'll validate it once we get there, but in order to set the predicate for the questions I really want to explore with you, I need to get some background information set first.

Are those 15 customers that you're aware of all single-family residential or are any of them multi-family?

A. I have no idea.

Q. Do you know the average or the typical size

of the installation?
A. No. I asked for system sizes, but they didn't have the info for all of them.
Q. Didn't have it? Did you get it for any of them?
A. I did get it for a subset.
Q. A subset of 15 is a pretty small number.
A. Yeah. There were just a few -- there were just a few. I think it might have been five.
It is -- in one of our discovery requests, they did list the AC generation capacity for at least the subset of those systems.
Q. Here's what I'm getting at -- and again, I will ask these questions, because it may speed us up tomorrow for Mr. Halley, because I'm going to ask him the same questions.
What I'm trying to get a sense on is, since the SSC is gonna be assessed on a kilowatt-per-month basis, based on nameplate capability, I'm sort of interested in knowing the average or the typical size of a customer installation so I can, sort of, say, well, the typical customer is gonna be paying an SSC monthly charge of X. That's really -- it's as simple as that. I'm just trying to get a basic number, and I

can't find that anywhere in the testimony or in the exhibits. You don't have it either?

A. Yeah, I mean, I don't -- the way the Company responded to discovery, they didn't know exactly that number. If you were to try to, kind of, just triangulate on a rough number in your head, if you take what I think was total generation, which is approximately 50,000 -- 50,000 kilowatt hours -- no -- I'm gonna butcher this is if I try to do it in my head, so.

Q. Don't do it in your head. I'm just trying to -- and again, Mr. Halley can help me with this. I'm trying to get a sense again of what a typical customer with a PV installation is gonna pay, by way of the SCC charge, on a monthly basis if this rider goes into effect and the customer takes service on the rider. It's going to be $6.02 per kilowatt of AC nameplate capacity, and I'm trying to get a sense of what that feels like when it shows up on an average monthly bill, that's all. Can't help any more than what you have there.

A. Sure. Although I think in the settlement testimony that number has been updated to -- I think it's 592 per kilowatt. So slightly different with the revenue --

Q. It's come in so quickly. I saw the reduction from 617 to 602, but I missed the reduction to, what, 592 now?

MR. DROOZ: That's right.

Q. All right. I could go back and read it later, but I'll get it now.

All right. So let's get to the question. So let's assume I'm not a solar PV customer, and I'm not gonna net meter. So the Company needs to recover from me my allocable portion, my fair share of it's fixed distribution system costs, which it says are, for me, $36 a month. It needs to recover that somehow or another from me. So it has two ways to do it now, right?

How does it do it? How does it recover that fixed cost now, from a customer who is not net metering?

A. Through the basic facilities charge and the volumetric rate.

Q. So a portion of it is used to set the basic facilities charge, a portion. And then another portion is recouped through the volumetric rate?

A. Correct, yeah. That's the volumetric rate.

Q. And between the two, the expectation is that, over the customer class -- over the entirety of the customer class, the Company will recover the full fixed cost of distribution for that customer class. That's the expectation.

A. Basic, kind of, cost-of-service equation.

Q. Okay. So now, I'm going to go on NBR, and I'm gonna put a 5 kilowatt array on my house, and I'm gonna try to goose it up and see if I can run as much as I can off that. And so now I'm going to pay -- I'm still going to pay the basic facilities charge, right? As I read the tariff.

A. That's correct.

Q. And you read the tariff the same way. So I'm gonna pay that.

And if I'm a net importer, if I don't generate as much as I use, whatever I buy from them, I'm paying the volumetric rate I would pay if I weren't an NBR customer, right?

A. That's right. You would be paying, you know -- you would be paying a portion of, kind of, the remainder --

Q. I would be paying a proportion. I might not be paying as much if I were not an NBR customer. I would be paying less of the portion of fixed charges included in the volumetric rate, but I'll still be paying some of that, right?

A. Right, you would be.

Q. And the bigger the gap between what I generate and what I consume, the more of it I'm paying?

A. Sure, of course. Yeah, I mean --

Q. Now I'm paying on top of that, $5.92, or whatever the number is in the settlement testimony, per month to go toward that fixed charge. So let's assume I got a 5 kilowatt system. And humor me on this. I'll round it up, because the math is easier for me to do late in the afternoon. Let's call it the $6 charge. 5 kilowatt nameplate capacity, $6 a month per kilowatt. I paying 30 bucks a month. I'm paying on top of that the basic facilities charge, which has some fixed cost recovery in it. Let's say I don't generate all my consumption, I'm paying something in volumetric rate. Where do I get the assurance that the Company is not over recovering its fixed cost of distribution?

A. Well, I think I'll -- I think what the Company would say is that its unrecovered fixed costs are not entirely within distribution, right? There is a contribution from the other, you know, transmission

Carolina Power Partners that, you know, the fact that you're paying 4450 does not necessarily indicate that they're over recovering costs.

Q. Okay. Thank you for that help.

A. My response to that is that, based on my calculations, the -- even if we assume, say, like, zero distribution value. In several cases, like the value of the customer-sided solar generation, because of its contribution to peak, is more on a dollar-per-kilowatt-hour basis than the flat average volumetric retail rate.

And so, you know, to the extent that there is some kind of under recovery of distribution costs occurring, you also need to consider that, basically, the customer is providing an additional service, but providing something of greater value than what they would otherwise pay for some of those other cost categories.

So, you know, they're kind of providing an in-kind service. Not a monetary service, but they are reducing the Company's other costs in a way that, kind of, at least will partially equalize -- equalize what might be, kind of, missing on the distribution side.

So my approach is that, you know, you need to kind of consider all of the different cost functions together, because in some cases, you know, if you properly calculate the value of peak reduction for the Company's Carolina Power Partners contract, it's gonna -- it will invariably be higher than the retail rate because the Company's costs for that are based on costs at peak.

Q. At peak?

A. And if you have a decent contribution to those costs at peak, your value, once spread across all solar production, can be higher than the retail rate. So, you know, I think of it from the standpoint of, like, is the customer a net benefit or are they a net cost? And if they are a net cost, how much are they a net cost, and that's what would determine if you were to establish, say, a standby charge, what that should be. My position is that the Company miscalculates that and makes mathematical errors.

Q. That's very helpful. Thank you. That is very helpful. Speaking of errors that you call out in your testimony, I want to just clean up a couple of things.

You indicated that -- you numbered them, and I'm sorry, I'll name them too. Issues 4 and 6, and

Issue 4 was the determination of the different SSC for commercial and commercial demand as opposed to residential.

Are you satisfied that issue has now been resolved?

A. I'm satisfied that they proposed a --

Q. You don't like the SSC, I understand that.

A. Yeah.

Q. But the fact that they used the residential data to set the commercial charge, you're satisfied that's been cleaned up?

A. Right. At least, in my understanding, they corrected the, kind of, mismatch between using residential data to set a commercial rate.

Q. Okay. That portion of the issue has been clarified, as far as you're aware. With respect to -- I think you testified on cross and redirect that you're satisfied now with respect to the Company's position, at least as I understand it, that it's agnostic on whether or not there is a reset or a continuing rollover.

The Company's, essentially, as I understand it, leaving it with the Commission?

A. Yeah.

Q. You're satisfied with that?

A. That they voiced an openness to doing what the Commission said? I mean, I suppose they have to do that anyway, but I'm gratified to hear that they are open and not opposed to it.

Q. That's fair.

A. You know, just to be clear, to the extent there are technological issues associated with that that I'm not aware of, let's find a solution that's not contrary to customer interests and resolve those technological issues.

So if there is a good way that's not exactly the way I recommend it, that's potentially fine.

Q. I want to ask you about one that hasn't been discussed yet, and again, I'm gonna ask Mr. Halley about these. What you call Issue 5, I call as using the inverter rating as a surrogate for the AC nameplate capacity, even though the calculations are supposed to be based on AC nameplate capacity.

Have you discussed that issue with the Company and explained why that's not correct?

A. Okay. So the basic -- the basic problem is that --

Q. I understand the problem. Have you discussed with it the Company?

A. I have not discussed that with the Company.

Q. Have you discussed it with Public Staff?

A. No, I have not discussed it with Public Staff.

Q. Seems like that's a fairly easy one to fix.

A. I don't know whether it's easy.

Q. You have not made any discussions with any parties about how to resolve that issue?

A. You know, other than relaying my opinion in testimony, no, I have not.

Q. Okay. Let me ask you a question about the PPR rate. So let's make the assumption, for purposes of the question, that the Commission authorizes the new NBR schedule.

So who are the customers who are still after that fine PPR rate to be of interest to them? I -- leave it aside -- I understand customers who are not eligible, such as ASU. They may need to look at a different rate schedule because they're not eligible for the NBR rate. I understand that customers who have system sizes over 1,000 kilowatts would not be eligible for the NBR rates.

So who are the types of customers who -- and, of course, as I read the tariff, people who are not buying from the utility at all, they are just PURPA QFs. They are not using the PPR rate.

Who is left to use the PPR rate?

A. I think that's my point. I don't know. I don't know why anybody would. And I wouldn't want it out there confusing people as an option.

Q. You have not been able to, sort of, characterize the type of customer whose situation or conditions might lead them to say PPR -- now I've got PPR, now that I've got access to that, PPR is the right way for me to go?

A. It might be plausible that a commercial customer that wants to, say, depreciate their system, and wants it, kind of, to be characterized as, basically, you know, a power generator, might find PPR preferable. But truthfully, I mean, I feel like the benefit -- the customer benefit difference between NBR and PPR would be so great, I just don't see why anybody would want to do it, unless for some reason they just have this urge to get a check. I don't see how it's financially beneficial, relative to NBR.

Q. Okay. Thank you, Mr. Barnes.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Good afternoon. I just had some follow-ups from Commissioner Clodfelter's questions to you.

And you were answering one of his questions, and I wrote down that the customer contribution at peak may be greater than the purchase rate, I guess, or tariff rate.

Did I understand that correctly?

A. I might have butchered the articulation of it; but in a sense, yes.

Q. Okay. But that's assuming that the customer can contribute at the peak?

A. Right. Or it's kind of more assuming that the solar system is going to make some contribution at peak at the different hours. That's the basis of -- that's when I talked about those different, kind of, solar orientation scenarios. I did those because different orientations or systems are gonna have a different level of production at 5 p.m. or 9 a.m. And so there is going to be -- there is always going to be some kind of derating of the nameplate capacity because production is not gonna be optimal at, kind of, typical peak times. But there will still be -- there will still be some. In my calculation, it was, kind of, mostly in the range of about 20 percent.

Q. Okay. But if the peak is at 4 a.m. in the morning, there would be no solar contribution, correct?

A. Sure. Except, I mean, none of New River Light and Power peaks are at 4 a.m., so.

Q. Thank you. And then you -- there was a question about the order in E-7, Sub 1146 about what the Commission said with respect to basic facility charges. And I believe I heard your testimony was, you know, we don't have that in front of us, and you cannot remember exactly if -- what the Commission said about basic facility charges. And, obviously, the Order speaks for itself.

But subject to check, would you agree that the Commission's Order states that, The Commission finds and concludes that the increase in the basic facility charge for the residential rate class schedules is just and reasonable and strikes an appropriate balance, providing rates that more clearly reflect actual cost causation?

A. I seem to remember something along those lines. And subject to check, I agree that that is something that the Commission may have said.

Q. And then --

A. Or would say.

Q. And then later on in the paragraph it states, The Commission agrees with witness Pirro's testimony that the failing to properly recover customer-related costs via fixed monthly charge provides an inappropriate price signal to customers and fails to adequately reflect cost causation.

Subject to check that the order states that?

A. Yeah, subject to check.

Q. Okay.

A. My mission here is to hopefully correct that misapprehension.

Q. Okay. Thank you, sir.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q. And I have one follow up from some testimony you provided to Commissioner Clodfelter talking about the PPR rate, and I think you testified that you believe that most customers would prefer the NBR schedule as opposed to the PPR schedule. And I think that you stated that you thought that the harm for having the PPR rate is that it would confuse customers.

Is that the only harm, and in what way -- because it seems like -- what would be the detriment to having the PPR rate, and how would customers -- from a practical standpoint, why would they be confused between these two rate schedules?

A. I mean, it's -- in my experience, it's not that hard to confuse customers. A lot of people don't spend a ton of time thinking about what -- how a tariff reads, and could see a number like, we're gonna pay you this amount, versus you're just gonna net your consumption against your production.

And I'm not saying that it would necessarily be common as a source of confusion, but I don't -- you know, that given that it's suboptimal from a customer's standpoint in any circumstance I can imagine, I guess I don't see the need to have a schedule that's far less optimal than another rate schedule that the Company -- that the customers qualifies for.

So even if one customer gets confused, that's too much for me, especially when I just don't see any benefit to it.

Q. Okay. Thank you.

COMMISSIONER KEMERAIT: Any further questions? Commissioner McKissick?

EXAMINATION BY COMMISSIONER McKISSICK:

Q. I want you to help me with this, and if you can clarify your testimony, you indicated that about 20 to 25 states use the basic customer method.

A. Yeah. It's -- I don't know the exact number, but it's about similar to that.

Q. All right. Now, let me ask you this. If you were to look back over, say, the last five years, is that trend increasing or is that trend decreasing, based upon your knowledge? And you seem to be very astute, in terms of having tracked this and followed this.

A. I would say it's relatively stable.

Q. Stable?

A. Yeah. Just from the standpoint of once -- it's pretty typical that, once a, you know, regulatory body kind of decides on how they want to do things, that just tends to -- there is a lot of inertia involved. One state where I can, you know -- where I can recall it changing recently was New Hampshire, in which they decided that they would -- made an affirmative decision, you know, making it clear, in no uncertain terms, that basic customer method is our method.

In South Carolina, they've gone in the other direction. Connecticut, they went more towards the basic customer method. Although that wasn't regulators, that was -- that was the legislature basically telling the regulators what to do.

So I don't know that there is a -- I don't know that there is a clear trend either way. There had been some on one side and some on the other.

Q. Okay. That's what was trying to determine, just based upon your observation.

So if it's 20 states that are now adopted the basic customer method, it would still be 30 states that have not?

A. Or are somewhere kind of in the middle or haven't really, like, established a firm -- you know, haven't really established, kind of, a line in the sand as to how they want to see things done.

Q. Sure. Thank you.

COMMISSIONER KEMERAIT: Okay. This brings us to the end of the day. So we're gonna be in recess until tomorrow morning at 10:00, and we will adjourn at 10:00 with questions on Commission questions. Thank you. We'll go off the record now.

(The hearing was adjourned at 5:00 p.m. and set to reconvene at 10:00 a.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 13th day of July, 2023.

Joann Bunze

NDTCA Signed Electronic Transcript

JOANN BUNZE, RPR
Notary Public #200707300112