PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Tuesday, July 11, 2023

TIME: 1:43 p.m. - 5:07 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 4

A P P E A R A N C E S:

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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 A M I N A T I O N (Cont'd.):

E X A M I N A T I O N (Cont'd):

E X H I B I T S

E X H I B I T S

P R O C E E D I N G S

COMMISSIONER KEMERAIT: Good afternoon, everyone. Let's go back on the record. Before we get started with questions on Commission questions, I have looked back through the cross-examination estimate times, and unfortunately, I think my math was wrong because I missed some cross times, so I recognize that it may take a little bit longer than I had expected before the break. That being said, we are going to finish today, and we always finish at five o'clock in the afternoon. So I would urge all the parties to be as succinct as they can be because we need to finish today. We do not have -- finding a time to come back would be very challenging, at this point, based upon the Commission's schedule, so we're going to work very hard to be done by five o'clock today.

Okay, so let's go ahead and get started, beginning with questions on Commission questions. Ms. LaPlaca.

MS. LAPLACA: I have none.

COMMISSIONER KEMERAIT: Okay. Appalachian Voices?

MR. JIMENEZ: No questions.

COMMISSIONER KEMERAIT: New River?

MR. DROOZ: Very briefly.

COMMISSIONER KEMERAIT: Okay.

EXAMINATION BY MR. DROOZ:

Q You were asked about the proposed five-year review of the MBR rate that's in the settlement. Given what you know about the size and resources of New River Light and Power would it make the most sense to do that type of review within the rate case context as opposed to hiring consulting firms and all the time that goes in, in trying to attempt that outside of a rate case?

A (Mr. McLawhorn) We certainly would like to minimize the expense on New River and their customers but of course I don't -- I don't know how long it would be before you would be back in for another rate case, so I would want to, at least, keep it no longer than the five years even if you're not back in for a rate case.

Q So it would be reasonable to say five years or the next rate case, whichever comes first?

A That would be fine with me, if that's agreeable to all other parties.

MR. DROOZ: That's all I have. Thank you.

MR. FELLING: Just one question in response to the line of questioning from both Commissioner Duffley and I believe Commissioner Kemerait on the resetting of solar credits annually.

EXAMINATION BY MR. FELLING:

Q Mr. McLawhorn, I'm trying to channel Jack Floyd as best I can here. Would you agree that the cross-subsidy issue that you discussed in terms of the annual reset is also an affordability issue to the extent that that cross-subsidy would be occurring from those who potentially cannot afford to install rooftop solar, subsidizing those who can afford to do it if there was no such reset?

A Yes. I should have mentioned that earlier. That has always been one of the Public Staff's concerns of customers who cannot financially afford to make an investment of that type, having to subsidize customers who can't.

MR. FELLING: No further questions.

COMMISSIONER KEMERAIT: Thank you. So I'll hear motions from the parties now.

MR. FELLING: Thank you, Presiding Commissioner Kemerait. At this time, I would move that the Appendix and exhibit attached to

Mr. McLawhorn's prefiled testimony be entered into the record and marked for identification as premarked. And I believe that the testimony was already addressed with the previous motion.

COMMISSIONER KEMERAIT: So seeing no objection, your motion to have exhibit admitted into the record is allowed.

MR. FELLING: Thank you.

(WHEREUPON, McLawhorn Exhibit 1 is received into evidence.)

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

THE WITNESS: Thank you.

COMMISSIONER KEMERAIT: Public Staff may call its next witness.

MR. FREEMAN: Thank you, Commissioner. The Public Staff calls John Robert Hinton.

COMMISSIONER KEMERAIT: Good afternoon, Mr. Hinton. If you'll place your left hand on the bible and raise your right.

JOHN ROBERT HINTON;
having been duly sworn,
testified as follows:

COMMISSIONER KEMERAIT: Thank you.

MR. FREEMAN: Thank you, Commissioner.

DIRECT EXAMINATION BY MR. FREEMAN:

Q Mr. Hinton, would you please state your name, business address, and title.

A My name is John Robert Hinton. My address is 430 North Salisbury Street, Raleigh, North Carolina, and I'm the Director of the Economic Research Division for the Public Staff.

Q On June 6, 2023, did you cause to be filed in these cases prefiled direct testimony consisting of 34 pages, two appendices, and 12 exhibits?

A Yes.

Q On July 6, 2023, did you cause to be filed in these cases prefiled settlement testimony consisting of seven pages and an exhibit? And I know the settlement testimony made certain alterations to your prefiled direct testimony.

A Yes, I did.

Q Mr. Hinton, if you were asked the question set forth in your prefiled direct and settlement testimony, as the settlement modified the direct, would your answers, as altered, be the same today?

A Yes. There's one change I'd like to make.

Q Oh, please.
A Prefiled direct testimony filed on June 6, on page 11 of my testimony, on line 8, the word decrease should be increase.
Q Okay. Well, then, let me reask it. With that change now, would your testimony be the same today, as in the changed testimony, as altered by the settlement testimony?
A Yes, it would.
Q Thank you.

MR. FREEMAN: Presiding Commissioner, at this time, I move that the prefiled direct and settlement testimony, with the correction by Mr. Hinton, be entered into the record in the transcript as if given orally from the stand, and that Mr. Hinton's two appendices, 12 direct testimony exhibits, and single settlement testimony exhibit be marked for identification in the same manner as they were when prefiled.

COMMISSIONER KEMERAIT: So Mr. Hinton's direct testimony filed on June 8 of 2023 consisting of 34 pages and his settlement testimony filed on July 6 of 2023, consisting of 7 pages, will be copied into the record as if given orally from the stand, including the correction that Mr. Hinton just testified to. The two appendices and the 12 exhibits attached to Mr. Hinton's direct testimony, and the one exhibit attached to the settlement testimony, will be marked for identification purposes as prefiled.

(WHEREUPON, Hinton Exhibits 1-12, Public Staff Hinton Settlement Exhibit 1 and Hinton Appendices A and B are marked for identification as prefiled.)

(WHEREUPON, the prefiled direct testimony and settlement testimony of John Robert Hinton is copied into the record as if given orally from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

JUNE 6, 2023

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

A. My name is John R. Hinton. I am the Director of the Economic Research Division of the Public Staff of the North Carolina Utilities Commission, representing the using and consuming public. My business address is 430 North Salisbury Street, Raleigh, North Carolina 27603. My qualifications and experience are provided in Appendix A.

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

A. The purpose of my testimony in this proceeding is to present the Commission with my findings and recommendation regarding the cost of capital for rates and charges applicable to electric service in New River Light and Power (NRLP).

Q. How is your testimony structured?

A. The remainder of my testimony is structured as follows:

I. Introduction and Background

II. Present Financial Market Conditions

III. Appropriate Capital Structure for Ratemaking

IV. Cost of Long-Term Debt

V. Cost of Common Equity

VI. Impact of Changing Economic Conditions

VII. Recommended Overall Cost of Capital

VIII. Customer Growth and Usage Adjustments

I. INTRODUCTION AND BACKGROUND

Q. What is the currently approved cost of capital for NRLP?

A. On March 29, 2018, the Commission approved 6.525% as the overall cost of capital in Docket No. E-34, Sub 46, NRLP's last general rate case. The components of NRLP's currently approved cost of capital are shown below, along with the cost of capital components from the preceding case.

Currently Approved
Cost of Capital
Docket No. E-34, Sub 46

Item	Ratio%	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.00%	3.800%	1.900%
Common Equity	50.00%	9.250%	4.625%
Total	100.00%		6.525 %

Q. What is the cost of capital requested by NRLP?

A. According to NRLP witness Randall E. Halley's testimony, NRLP is proposing an overall return of 7.007%. The recommendation is based on a hypothetical 48% debt and 52% common equity capital structure, a 4.20% cost rate of long-term debt, along with a recommended rate of return on common equity of 9.60%, as shown below:

NRLP Proposed
Cost of Capital
as of December 31, 2021

Item	Ratio%	Cost Rate	Weighted Cost Rate
Long-Term Debt	48.00%	4.20%	2.015%
Common Equity	52.00%	9.60%	4.992%
Total	100.00%		7.007%

Q. What is your recommended cost of capital for NRLP?

A. I determined that 6.07% is an appropriate overall cost of capital. This recommendation is based on a hypothetical capital structure consisting of 50.00% common equity and 50.00% long-term debt. I have incorporated a cost rate of long-term debt of 3.23% and a cost rate of common equity of 8.90%.

Public Staff Recommended
Cost of Capital
as of December 31, 2022

Item	Ratio%	Cost Rate	Weighted Cost Rate
Long-Term Debt	50.00%	3.23%	1.63%
Common Equity	50.00%	8.90%	4.45%
Total	100.00%		6.07%

Q. Are there any legal and economic guidelines to follow when determining the cost of capital to a public utility?

A. Yes. The appropriate legal and economic guidelines are thoroughly addressed in prior Commission orders (including the Commission's July 23, 2015 Order on Remand in Docket No. E-22, Sub 479). Rather than repeat prior discussions, I will summarize the two cases that established the basic principles for determining rate of return on equity (ROE).

In Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope), the U.S. Supreme Court stated:

> [T]he returns 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 its credit and to attract capital.

Id. at 603.

In Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923) (Bluefield), the U. S. Supreme Court stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other

> business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

Id. at 692-93.

These two decisions recognize that utilities are competing for the capital of investors and provide legal guidelines as to how the allowed rate of return should be set. The decisions specifically speak to the standards or criteria of capital attraction, financial integrity, and comparable earnings. The Hope decision, in particular, recognizes that the cost of common equity is commensurate with risk relative to investments in other enterprises. In competitive capital markets, the required return on common equity will be the expected return foregone by not investing in alternative investments of comparable risk. For the utility to attract capital, possess financial integrity, and exhibit comparable earnings, the return allowed on a utility's common equity should be that return required by investors for stocks with comparable risk.

It is widely recognized that a public utility should be allowed a rate of return on capital which, under prudent management, will allow the utility to meet the criteria or standards referenced by the Hope and Bluefield decisions. If the allowed rate of return is set too high, consumers are burdened with excessive costs, current investors receive a windfall, and the utility has an incentive to overinvest. If the return is set too low, and the utility is not able to attract capital on reasonable terms to invest in capital improvements for its service area, then its ability to meet its future service obligations may be impaired. Because a public utility is capital intensive, the cost of capital is a very large part of its overall revenue requirement and is a crucial issue for a utility and its ratepayers.

Q. How did you determine the cost of capital that you recommend in this proceeding?

A. To determine the cost of capital, I performed a study consisting of three steps.

First, I determined the appropriate capital structure. Firms normally finance assets with a combination of debt capital and equity capital.

Because each form of capital has a different cost, especially after income tax considerations, the relative amounts of each form that are employed to finance the assets can have a significant influence on the overall cost of capital.

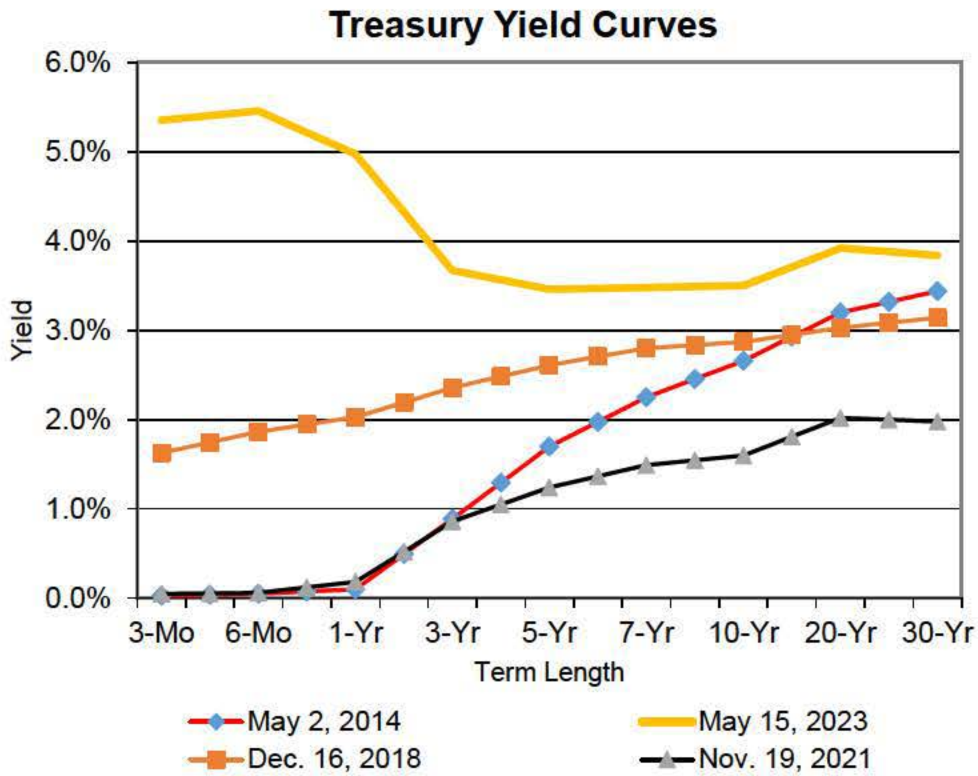
Second, I determined the cost rates for both forms of financial capital.

Third, by combining the capital structure ratios with the associated cost rates, I calculated an overall weighted cost of capital.

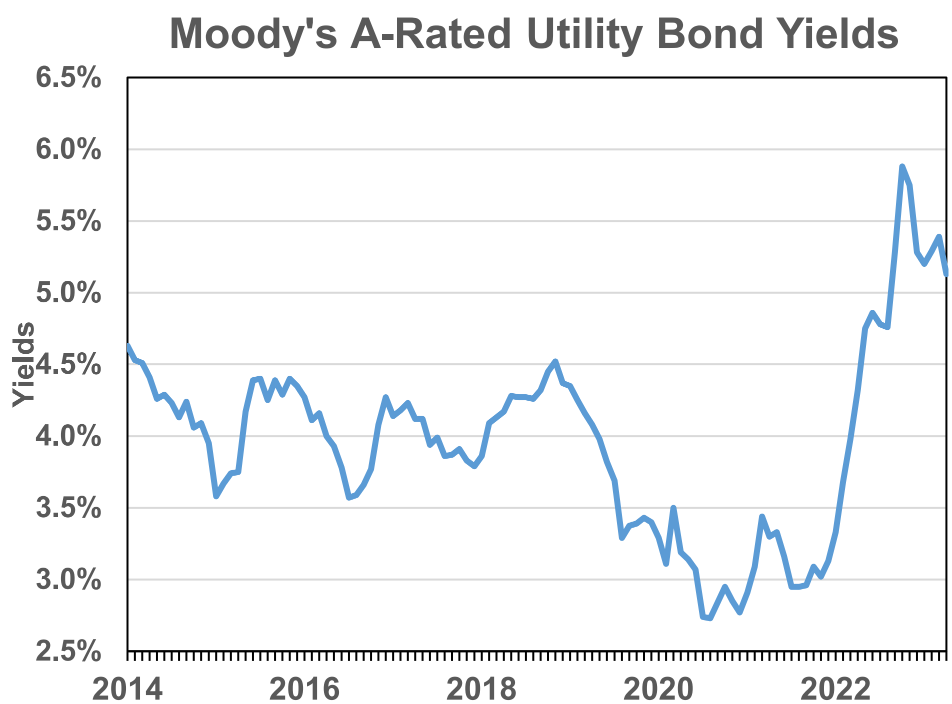
II. PRESENT FINANCIAL MARKET CONDITIONS

Q. Can you briefly describe the current financial market conditions?

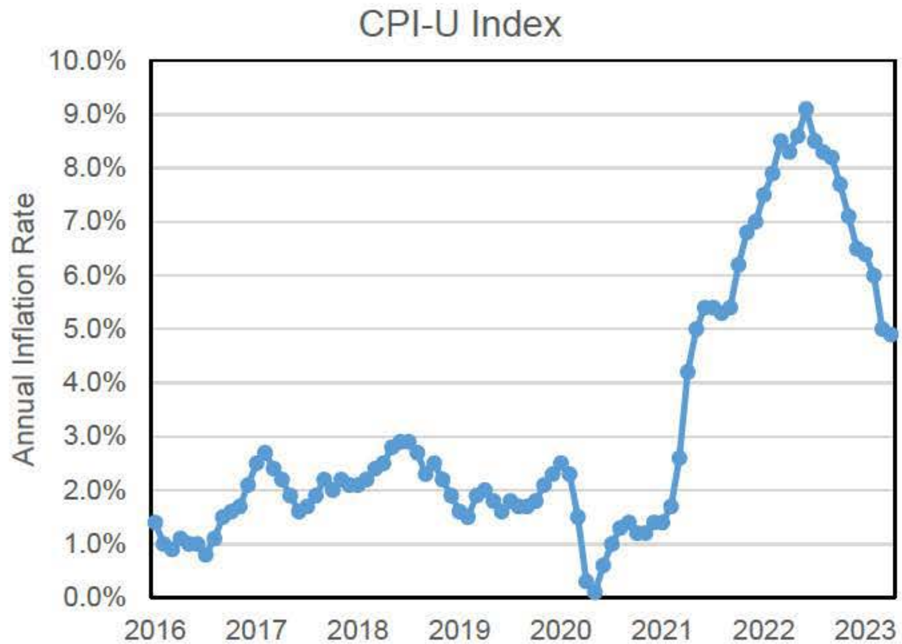
A. Yes. As compared to the last decades there has been a resurgence of inflation, which has contributed to an increase in inflationary expectations and increases in nominal interest rates. The changes in the U.S. Treasury bond yield curves illustrate differences in increases in interest rates over various terms. The largest increase in the difference from current yields compared to the last 12 months is with the short-term securities of one year or less, which have increased by over 380 basis points. However, the average increases in the 10- and 20-year term U.S. Treasury yields have risen approximately 51 basis points over the last 12-months.



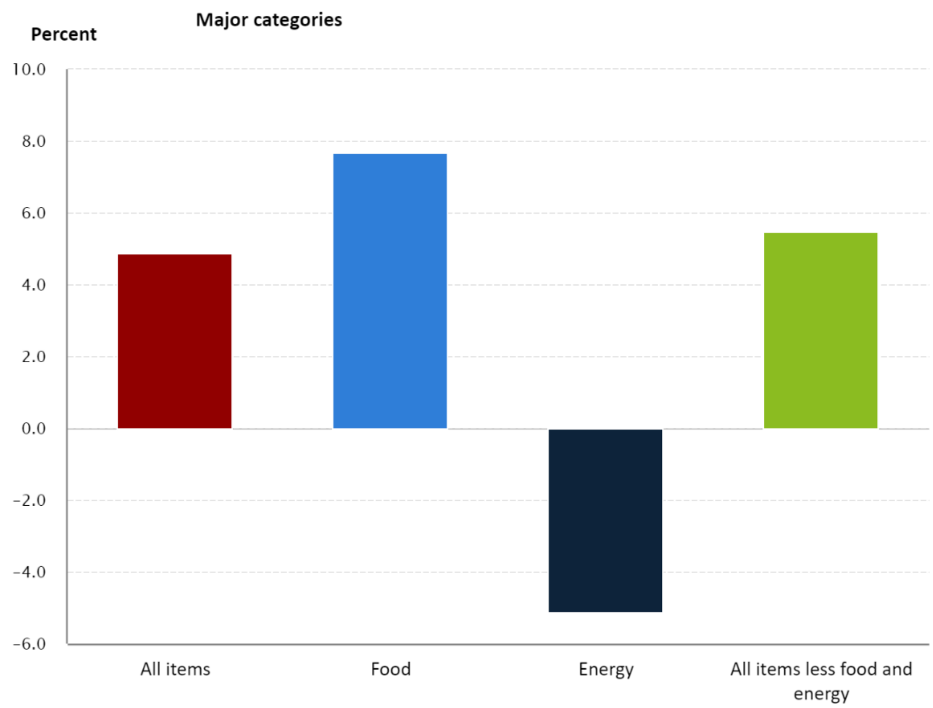
With particular importance to utility financings, yields on long-term “A” rated utility bonds, as reported by Moody’s *Bond Survey*, are 5.13% for April 2023. Although elevated compared to historical returns, this is down 75 basis points from the 5.88% rate observed in October 2022. The changes in the A-rated Public Utility bond yields are shown below:



As of April 2023, the annual inflation rate was 4.9%, as measured by the Consumer Price Index for all items with urban consumers (CPI-U), which is down from its highest rate of 9.1% observed in June 2022. The chart below illustrates the recent downward trend.



Per the most recent release from the U.S. Bureau of Labor Statistics, the index for electricity decreased 0.7% in April, as it also did in March 2023. Below is the 12-month percentage change in the consumer price index for selected categories (not seasonally adjusted) from the April 2023 release from the U.S. Bureau of Labor Statistics. As shown below, notwithstanding the overall increase of all items, the energy index has decreased by 5.1% over the past year.

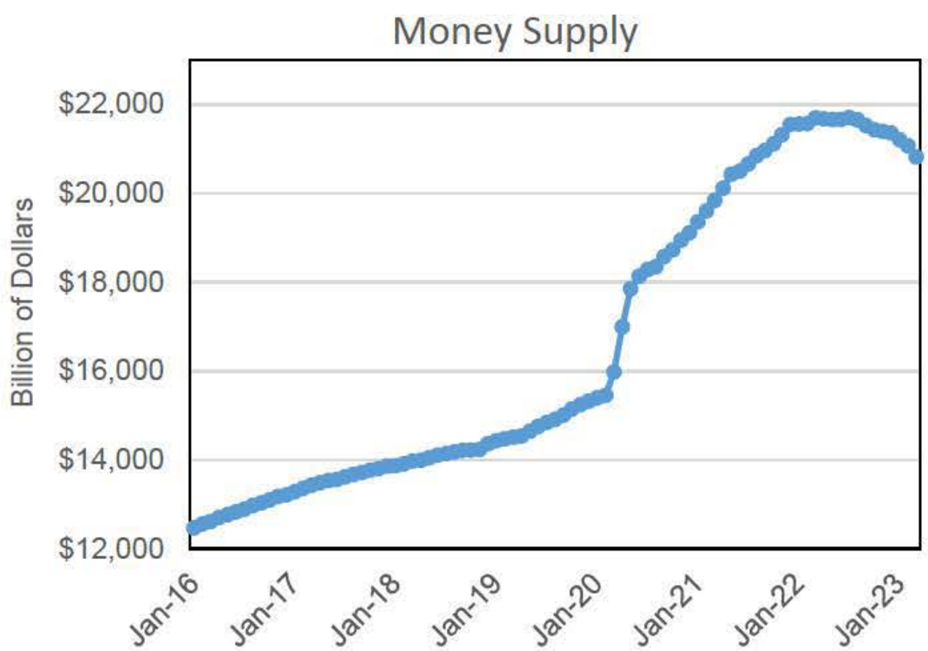


I maintain that the decreases in the utility bond yields and the recent decreases in treasury yields are, in part, due to the decreased inflation rates over the last nine months from their peak observed for June 2022.

In my opinion, the decreased inflation rate has been largely driven, in part, by the decreased growth rate of the money supply as measured by M2.[1] I believe that the restrictive monetary policy by the Federal

[1] https://fred.stlouisfed.org/series/M2SL

Reserve illustrated in the below graph represents a significant factor with the decreasing inflation rates.[2]



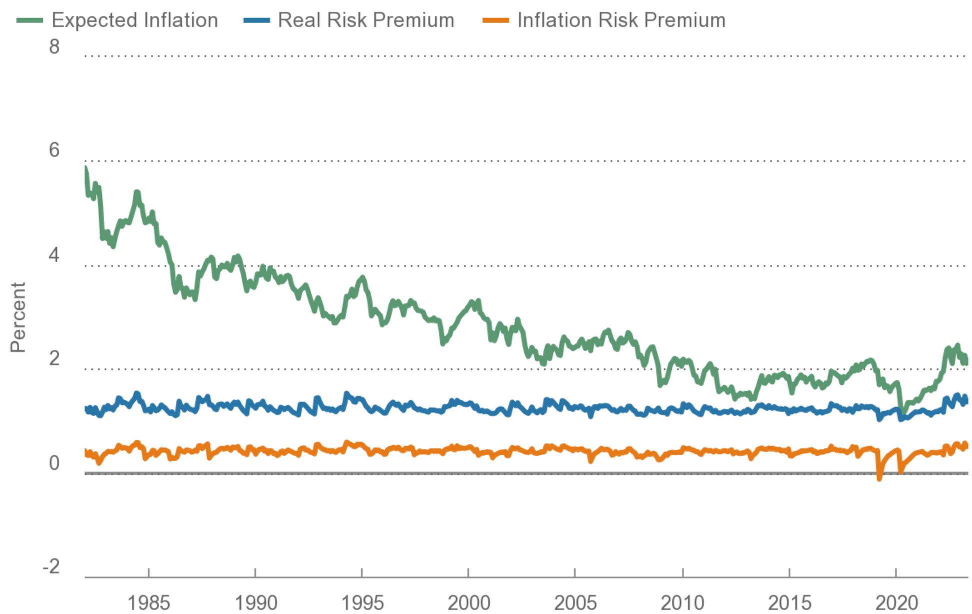
However, there remains debate about the timing and effects of monetary policy.[3] Furthermore, monetary policies have contributed to the recent 1.1% annual growth rate of the Gross National Product that reflects a slowing economy and the rising belief of a near-term recession.

[2] Milton Friedman and Anna j. Schwartz, A Monetary history of the United States, 1867-1960, National Bureau of Economic Research, Princeton University Press, 1963.

[3] Economic Brief, Why are Economists still Uncertain about the effects of Monetary Policy, Federal Reserve Bank of Richmond, May 2023.

Lower long-term inflation expectations are observed in the analysis performed by the Federal Reserve Bank of Cleveland. As of May 1, 2023, the Federal Reserve Bank of Cleveland estimated the expected annual inflation rate[4] over the next 10 years to be 2.2%.

Ten Year Expected Inflation and Real and Inflation Risk Premia:



Source: Federal Reserve Bank of Cleveland calculations based on data from Blue Chip, Bloomberg, Burea of Labor Statistics, Federal Reserve Bank of Philadelphia, Federal Reserve Board, Haver Analytics, and th model of Haubrich, Pennacchi, and Ritchken, 2012. "Inflation Expectations, Real Rates, and Risk Premia: Evidence from Inflation Swaps." Review of Financial Studies, 25(5).

This discussion demonstrates the considerations of present financial and economic conditions used in arriving at the Public Staff's recommended return on equity and overall cost of capital. It is my

[4] https://www.clevelandfed.org/en/indicators-and-data/inflation-expectations

belief that the heightened expectations of above-normal inflation and interest rates have peaked and are now fading.

III. APPROPRIATE CAPITAL STRUCTURE FOR RATEMAKING

Q. Please explain the term "capital structure" and how the capital structure approved for ratemaking purposes affects rates.

A. The typical electric power utility obtains external capital from investors by borrowing debt and issuing common equity. The capital obtained from debt and equity investors, along with retained earnings, is utilized to finance assets. The capital structure is simply a representation of how a utility's assets are financed. A goal for ratemaking is to use a reasonable mix of debt and equity capital that allows the opportunity to attract capital and maintain the utilities financial integrity while also maintaining the cost of capital at the <u>lowest</u> overall rate that is fair to the utility investor and the utility rate payer.

Q. From an investors' perspective, is NRLP a typical electric utility?

A. No. First, NRLP is a wholly owned operation of Appalachian State University (ASU). Second, relatively little of NRLP's assets are financed with debt capital. According to the December 31, 2022 financial statements, NRLP's capital structure contains 26% debt and 74% common equity, which in my opinion is unreasonable for ratemaking. Such a large degree of common equity contributes to a higher overall cost of capital unless adjustments are made to reduce the cost rate for equity to reflect the lower financial risk. The absence of publicly traded electric utility companies with similar capital structures makes it quite difficult to arrive at a reasoned and market-based capital structure and cost rates. As such, the use of a hypothetical capital structure is appropriate.

While the goal of my investigation is to determine the appropriate cost rate of debt capital and cost rate of common equity capital for a risk-equivalent electric utility, it is incumbent to recognize the unique ownership of this utility as compared to other investor-owned utilities (IOUs), which I will further address with the cost rate of common equity.

Q. Is the requested capital structure identified in NRLP witness Halley's testimony appropriate for ratemaking purposes in this proceeding?

A. No. NRLP has requested the use of a 48% debt ratio and a 52% common equity ratio. The proposed capital structure is more appropriate for a vertically integrated electric utility that must compete for investors to provide both debt and equity capital to assist in the financing of its operations and capital expenditures.

Q. What is your recommended capital structure?

A. I recommend the use of a hypothetical capital structure comprised of 50% common equity and 50% debt. This structure is reasonable for the reduced investment risk associated with electric distribution-only utilities. I have reviewed the data associated with distribution-only utilities since NRLP purchases its power from wholesale generation providers, as compared to a vertical integrated utility. The approved equity ratios[5] for electric distribution cases over the period 2017 through April 30, 2023, is approximately 50.00%, as shown in Public Staff Hinton Exhibit 1.

IV. COST OF LONG-TERM DEBT

Q. Is the requested cost of long-term debt appropriate for ratemaking purposes in this proceeding?

A. No. NRLP has requested a cost rate of 4.20%, which is reported to be the average approved cost of debt for recent rate cases involving Piedmont Natural Gas, Inc. (PNG) and Public Service Company of

[5] S&P Global Market Intelligence, Major Energy Rate Case Decisions – January-March 2023, April 26, 2023.

North Carolina, Inc. (PSNC). In my opinion, these debt cost rates do not reflect the credit risk of NRLP; rather, the proposed cost of debt is reflective of the credit risk of these privately-owned natural gas distribution companies. Even though the credit risk of NRLP is not explicitly rated, ASU's General Revenue bonds are rated Aa3 by Moody's, as compared to an A3 for PNG and Baa1 for PSNC. NRLP is not an independent or separate entity but is rather an operating division of ASU. Nonetheless, I accept that the credit risk of NRLP may be slightly higher than for ASU; however, any appraisal of this utility must consider the ultimate owner of the utility system by the State of North Carolina. Lastly, the proposed cost rates of PNG and PSNC bonds reflect investor-required returns net of taxes; however, the Tax Certificate associated with its most recent loan from Truist Bank confirms that income from interest payments is excluded from taxes as shown in Public Staff Hinton Exhibit 2.

Q. What is your recommended cost of long-term debt?

A. I recommend an embedded cost of debt of 3.23%. This cost rate is based on the actual debt of NRLP as of December 31, 2022, and I imputed additional debt to match the 50% of debt capital of the Public Staff's proposed rate base. The actual embedded cost of debt reflects the weighted average of NRLP's three outstanding long-term issues;

a May 5, 2016 loan of a $3.7 million for 10-years at 2.82%, a December 10, 2020 loan of $6.5 million at 1.73%, and a Oct. 12, 2022 loan for $3.0 million loan at 4.77%. In addition, to the outstanding balance of $10.5 million, I have imputed approximately $4.5 million of additional debt with NRLP's outstanding balance. To estimate the cost rate of the $4.5 million issue, I averaged the treasury spreads for the two existing fixed rate Truist loans to calculate a current cost rate of 4.35%. Therefore, the 3.23% represents a weighted cost rate of the existing Truist debt and the cost rate for an additional debt issue shown in Public Staff Hinton Exhibit 3. As such, the recommended cost rate of debt is aligned with the credit risk of NRLP.

V. COST OF COMMON EQUITY

Q. How did you determine the cost of common equity?

A. Even though NRLP does not have to compete in the equity market with other comparable risk utility and non-utility companies, I believe the appropriate starting point is to determine the cost rate of common equity as if NRLP had to obtain external capital from the marketplace. As such, I used the Discounted Cash Flow (DCF) model on a group of electric utilities that exhibit low investment risk, and I have used the Regression Analysis of Allowed Returns on Equity for electric distribution utilities to determine the appropriate cost of common equity. In prior testimony on cost of equity, I have used a comparable earnings method as a check on my other methods; however, given the lack of traded common stocks of distribution-only utilities to derive a historical measure of earned returns, I feel that the use of this approach creates more uncertainty instead of providing any market insight.

Q. Would you please describe the DCF model?

A. The Discounted Cash Flow model is a method of evaluating the expected cash flows from an investment by giving appropriate consideration to the time value of money. Theory dictates that the price of the investment will equal the discounted cash flows of returns. The return to an equity investor comes in the form of expected future dividends and price appreciation. However, as the new price will again be the sum of the discounted cash flows, price appreciation can be ignored and attention focused on the expected stream of dividends. Mathematically, this relationship may be expressed as follows:

Let D_1 = expected dividends per share over the next twelve months;

g = expected growth rate of dividends;

k = cost of equity capital; and

P = price of stock or present value of the future income stream.

Then,

$$P = \frac{D_1}{1+k} + \frac{D_1(1+g)}{(1+k)^2} + \frac{D_1(1+g)^2}{(1+k)^3} + \ldots\infty\ldots + \frac{D_1(1+g)^{t-1}}{(1+k)^t}$$

This equation represents the amount an investor would be willing to pay for a share of common equity with a dividend stream over the future periods. Using the formula for a sum of an infinite geometric series, this equation may be reduced to:

$$P = \frac{D_1}{k - g}$$

Solving for K yields the DCF equation:

$$K = \frac{D_1}{P} + g$$

Therefore, the rate of return on equity capital required by investors is the sum of the dividend yield (D_1/P) plus the expected long-term growth rate in dividends (g).

Q. How did you identify a group of companies comparable in risk to NRLP?

A. I have identified companies that exhibit investment-related risk measures common with the electric utility industry. I started with over 1,700 companies analyzed in Value Line that are traded in domestic stock exchanges. From this initial group, I selected electric utility companies with following criteria:

1. Safety Ranks of 1 or 2,
2. Beta coefficients of 0.85 or less,
3. Earnings Predictability Rank of 90 or more
4. S&P Bond Rating of BBB+ or higher.

These screens were produced by a group of 12 electric utility companies. From there I eliminated Fortis due to it being traded overseas and Dominion because of a relatively recent dividend cut. The risk measures for the comparable group of electric utility companies are shown in Public Staff Hinton Exhibit 4.

Q. How did you determine the dividend yield component of the DCF?

A. I calculated the dividend yield by using the Value Line estimate of dividends to be declared over the next 12 months divided by the price of the stock as reported in the Value Line Summary and Index sections for each week of the 13-week period from February 17, 2023, through May 12, 2023. The averaging period tends to smooth out short-term variations in the share prices and yields. This process resulted in an average dividend yield of 3.39% for my comparable group.

Q. How did you determine the expected growth rate component of the DCF?

A. It is reasonable to assume that investors develop their expected long-term growth with investment returns by examining actual, known past performance and stock analysts' forecasts of the growth of earnings, dividends, and common equity. I have used both historical growth rates and forecasted growth rates to determine an expected growth rate.

First, I employed the growth rates of the comparable group in earnings per share (EPS), dividends per share (DPS), and book value per share (BPS), as reported in Value Line over the past five to ten years. Value Line employs a three-year smoothing process in an attempt to avoid the distortion that may be associated with choosing an unrepresentative high or low beginning or ending point.

Second, I employed the forecasts of growth rates of the comparable group in EPS, DPS, and BPS, as also reported in Value Line. These forecasts are prepared by analysts of an independent advisory service. This service is widely available to investors and should also provide an estimate of investor expectations. Third, I incorporated the consensus of various analysts' five-year earnings forecasts of EPS growth rates as published by the Yahoo Finance website.

In Public Staff Hinton Exhibit 5, I have presented the dividend yields and various growth rates as described above for the comparable group. That exhibit also shows the resulting DCF range of estimated cost rates for common equity.

Q. What is your conclusion of the cost of common equity based on the DCF method?

A. Based upon the DCF method and giving primary weight to the DCF results that rely on the predicted future growth rates of EPS, DPS, and BPS, I determined that the cost of common equity is within the range of 8.64% to 9.20%. This range is based on a dividend yield of 3.39% and an expected growth rate of 5.09% to 5.40%.

Q. Please describe the regression analysis method you applied to electric distribution-only decisions.

A. I used a regression analysis to analyze the relationship between allowed returns on equity for distribution-only electric utilities and Moody's index yields for A-rated utility bonds. I first presented a similar method (developed by Federal Energy Regulatory Commission staff) to this Commission in DNCP's 1993 rate case, Docket No. E-22, Sub 333.

Q. Please continue.

A. This risk premium method attempts to quantify the risk premium that equity investors require to invest in a utility's stock instead of its bonds. The regression analysis incorporates the annual average allowed returns on equity for distribution-only related investments as the dependent variable and the average "A" rated Moody's bond yield as the independent variable. The use of utility bond yields is preferred over the use of US treasury yields because it allows the examination of the added risk premium associated with an investment in electric utility common stocks over a relatively secure investment in utility bonds. Page 1 of Public Staff Hinton Exhibit 6 presents the allowed ROEs and public utility yield data, while page 2 presents the results of the regression analysis that provides an estimate of the current cost of common equity for a distribution-only electric utility.

Q. What did you conclude from your regression analysis of allowed equity returns?

A. The regression equation quantifies the historical relationship (2007-2023) of allowed returns and yields on Moody's public utility bonds. I applied this historical relationship to a recent six-month average bond yield to generate a predicted estimate for the current cost of equity of 9.76%, as shown on page 2 of Exhibit 6.

Q. Please discuss the historically allowed ROE for distribution-only providers.

A. The average allowed ROE for distribution-only providers reflects lower investment risk and lower awarded returns of 9.19% relative to vertically integrated electric utilities of 9.61%. This figure stems from data compiled through April 20, 2023, as reported by Regulatory Research Associates and is set forth in Hinton Exhibit 7. This data point is not dispositive but does support my analyses.

Q. Will you summarize your conclusions on the cost of equity for NRLP?

A. Yes. I employed the DCF method on a comparable risk group of electric utilities and determined that a reasonable range is 8.49% to 8.80%. The Regression Analysis of Allowed ROEs method provided a single estimate of 9.76%. This produces cost of equity estimates ranging between 8.49% and 9.76%.

NRLP confronts operational risks similar to a distribution-only electric utility. Recently, NRLP experienced the capital requirements associated with a new substation, as well as having sufficient capital available to purchase power during the spike in its power costs resulting from increased natural gas prices in 2021 and 2022.

While the business risk to NRLP is comparable to similar utilities, its management does <u>not</u> face the same commitment, accountability, and pressure to offer its equity investors a rate of return commensurate with the investment risk as other investor-owned utilities. In my opinion, these factors justify an allowed return on equity that is at the lower end of the range of reasonableness. In my judgment, an 8.90% ROE is a reasonable estimate that is rounded from the 8.92% average of the three DCF estimates and the risk premium estimate shown on Public Staff Hinton Exhibit 8.

VI. IMPACT OF CHANGING ECONOMIC CONDITIONS

Q. To what extent does your recommended rate of return on equity take into consideration the impact of changing economic conditions on customers?

A. The determination of the rate of return for purposes of compensating investors must be based on the requirements of capital markets. However, as noted by the North Carolina Supreme Court in recent decisions, it is also necessary to consider the impact of changing economic conditions on consumers when determining the ROE.

In this case, I have made no quantitative adjustment to my recommended rate of return to reflect the impact of economic conditions on customers. Rather, it is a qualitative consideration in my review. It should further be noted that under North Carolina law the rate of return on common equity should be set as low as possible without impairing NRLP's reasonable access to capital, as set forth in the Hope and Bluefield cases discussed previously.

I am aware of no clear numerical basis for quantifying the impact of changing economic conditions on customers in determining an appropriate rate of return on equity in setting rates for a public utility. Rather, the impact of changing economic conditions nationwide is inherent in the analytical methods and data I used to determine the cost of equity for utilities that are comparable in risk to NRLP. I have also considered the impact of changing economic conditions on customers from two other perspectives. However, I reviewed recent economic data applicable to the Town of Boone, North Carolina and Watauga County.

With regard to economic data for North Carolina and NRLP's service area, I have reviewed county-wide data on total personal income and income per capita for the years 2019 through 2021 with State-wide data through 2022, as compiled by the Bureau of Economic Analysis (BEA);[6] data compiled by the North Carolina Department of Commerce; and data compiled by City-Data.com.[7] All of the information indicates that the average level of per-capita income in Boone is lower than the State of North Carolina as a whole. The 2021 per-capita income published by the BEA shows that the North Carolina average per capital income is approximately 17% greater

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[6] https://www.bea.gov/data/income-saving/personal-income-county-metro-and-other-areas

[7] http://www.city-data.com/city/Boone-North-Carolina.html

than for Watauga County. According to the County Profiles[8] published by the North Carolina Department of Commerce, Watauga County is considered to have a County Distress Score of “2” out of “3”. The County unemployment rate for March 2023 is 3.1%, which is better than the 3.5% statewide unemployment rate. Given that Boone has a higher percentage of workers in the food and service industry, it is not unexpected that the unemployment rate would be relatively low; however, this positive indicator is somewhat offset with the significantly lower per-capital income for Watauga County.

In addition, the proposed increase in residential rates would result in a $139 average bill, assuming a 1,000-kWh usage. This is similar to the $133 average energy bill that same customer would receive from Blue Ridge Electric Membership Corporation or the $138 bill they would receive from Duke Energy Progress. NRLP customer bills would be higher than North Carolina customers served by Duke Energy Carolinas and Dominion Energy.

[8] https://www.nccommerce.com/lead/

VII. RECOMMENDED OVERALL COST OF CAPITAL

Q. What is your recommended overall rate of return?

A. I recommend an overall cost of capital of 6.07%, as shown in Public Staff Hinton Exhibit 8. This overall cost of capital is comprised of a hypothetical capital structure comprised of 50% debt capital and 50% equity capital, a 3.12% cost rate for long-term debt, and an 8.90% cost rate of return on common equity cost rate.

Q. Did you perform any tests of reasonableness with your recommended rate of return on equity and overall cost of capital?

A. Yes. Based on the recommended capital structure and cost rate of debt, and the recommended ROE, the pre-tax times interest coverage ratio (TIER) is 4.3 times, which is slightly higher than most of the TIER ratings that I recommend to this Commission, and this recommendation should enable NRLP to meet its debt service covenants with Truist Bank.

VIII. CUSTOMER GROWTH AND USAGE ADJUSTMENTS

Q. Please explain the customer growth adjustment.

A. The customer growth adjustment adjusts revenues by an amount that represents the growth in kilowatt-hour (kWh) sales due to the change in the number of customers. The revenue adjustment is calculated by multiplying the total kWh adjustment by average customer class rates based on annualized revenues divided by per book sales.

Q. Did the utility adjust revenues for customer growth?

A. No. The NRLP based total revenues on the actual kWh sales and number of bills generated during the test year.

Q. How did you adjust for customer growth?

A. I used regression analysis to derive equations that best fit historic billing data ending December 31, 2022. In so doing, my analysis fit 12-, 24-, 36- and 48-month data to linear, exponential, power, logarithmic, quadratic, cubic and quartic equations. The equation with the highest adjusted r-square[9] value was used to calculate the representative end-of-period (EOP) level of customers for the

[9] The R-square measures the degree of explanatory power of the regression equation, which is adjusted to the degrees of freedom or the number of observations minus the number of parameters.

Residential, Commercial Non-demand, Commercial Demand, and ASU Campus rate classes. The change in the number of customers was determined by taking the difference between the calculated EOP level of customers and the actual bills for each month of the test period, which added 2,563 customers. The results of the regression based EOP customer growth adjustment as of December 31, 2022, for its residential, commercial, and lighting classes increased its energy sales of 3,877,543 kWh, which equates to $373,421 increase in its EOP revenue, as shown in Hinton Exhibits 9 and 10. The revenue adjustment associated with customer growth as shown in Exhibit 10 was provided to Public Staff witnesses Johnson and Morgan for incorporation into their schedules.

Q. Did you make any further adjustments to the revenues?

A. Yes. To account for changes in the energy sales per customer for the EOP customers, I calculated a usage adjustment for each rate class. The usage adjustment was based on the difference in the annual average usage per customer between the year ending December 31, 2021, and the year ending December 31, 2022. The difference was then multiplied by the regression based EOP customers. The total usage adjustment increased sales by 4,606,715 kWh, which equates to a revenue increase of $370,613, as shown in

Public Staff Hinton Exhibits 11 and 12. The revenue adjustment associated with usage as shown in Public Staff Hinton Exhibit 12 was provided to Public Staff witnesses Johnson and Morgan for incorporation into their schedules.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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

July 6, 2023

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

A. My name is John R. Hinton, and my business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Director of the Economic Research Division of the Public Staff.

Q. Are you the same John R. Hinton whose direct testimony was filed in this docket on June 6, 2023?

A. Yes.

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

A. The purpose of my settlement testimony is to support the Agreement and Stipulation of Settlement between New River Light and Power Company and the Public Staff dated July 5, 2023 (Settlement), as it relates to the cost of capital and the usage adjustment to the test year.

Q. What is the cost of capital in the settlement?

A. The Public Staff and the Company have agreed to a 6.165% cost of capital in this proceeding. The overall cost rate is comprised of a 9.10% rate of return on common equity (ROE) and a 3.23% cost rate of long-term debt, which is proportionally allocated to a capital structure that for ratemaking purposes is deemed to consist of 50.00% common equity and 50.00% long-term debt.

Q. What is your experience with, and understanding of, settlements in similar general rate case proceedings?

A. It has been my experience that settlements are generally the result of good faith "give and take" and compromise-related negotiations among the parties to utility rate proceedings. Settlements, as well as the individual components of the settlements, are often achieved by the respective parties' agreements to accept otherwise unacceptable individual aspects of individual issues in order to focus on other issues. Settlements sometimes result in a "global" resolution of all the issues that would otherwise be litigated in a rate proceeding, and are sometimes restricted to resolution of one or more individual issues. Resolving a case by settlement allows the utility to avoid or reduce the costs it may have otherwise incurred in litigation and hearings. The Settlement in this proceeding is global with respect to the contested issues identified by the Public Staff and represents the results of "give and take" good-faith negotiations.

Q. Did you participate in the negotiations leading up to the settlement in this proceeding?

A. Yes, I participated in the negotiations leading up to the Settlement.

Q. Do you agree that the cost of capital components of the proposed settlement are reasonable within the context of the overall settlement?

A. Yes, I do. As with other settlements, the Settlement cost of capital components in this proceeding represent a compromise by both parties in an effort to reach agreement. Furthermore, the Settlement cost of capital components are the result of good faith negotiations and compromises.

Q. Please explain why the proposed capital structure ratio is reasonable.

A. As noted in my direct testimony filed on June 6, 2023, over the prior five years the average common equity ratio for an electric distribution utility is approximately 50.00% which is supportive of the settled common equity ratio.

Q. Please comment on the settlement, particularly as it relates to the ROE.

A. The Company and Public Staff have fundamentally different views of current market conditions and the current cost of capital. Neither party convinced the other to change its view of the cost of capital issues, but the Public Staff and NRLP have found a way to bridge their differences, which results in a reasonable Settlement ROE.

Q. How does the settlement 9.10% ROE compare to the results of the analytical models used by you and by the company?

A. The Settlement ROE of 9.10% is 20-basis points above my recommended cost of equity in my direct testimony. Secondly, the Settled ROE reflects a 50-basis point reduction from witness Haley's proposed 9.60% ROE. In addition, the 9.10% ROE is 15-basis point below their currently approved ROE of 9.25%[1]. Finally, it is in line with the average authorized ROE for distribution-only electric utilities reported by RRA and found as Hinton Direct Testimony Exhibit 7, especially in light of the reduced risk the utility enjoys as a governmental entity.

Q. Is the resulting overall cost of capital reasonable?

A. Yes. The Settlement 6.165% overall cost of capital is reasonable as it reflects the agreed upon capital structure, cost of common equity, and cost of debt shown in Public Staff Hinton Settlement Exhibit I. The higher ROE contributed to increasing the pre-tax interest coverage ratio in my direct testimony from 4.3 to 4.4 times. It is believed that the Settlement should help provide for an adequate level of income to attract capital, fairly and justly compensate the utility as required by law, and fund day-to-day operations. While funding operations is generally not considered a driving factor in

[1] On January 19, 2018 the Public Staff filed a proposed Settlement containing a 9.25% ROE in Docket No. E-34, Sub 46.

regard to the cost of capital for larger electric utilities, in 2022 NRLP's average cost of purchased power practically doubled from 2021, which prompted the Company to seek additional debt capital. Lastly, the 6.165% cost rate indicates a significant reduction in the NRLP's currently approved 6.525% overall cost of capital.

Q. What is the usage adjustment in the settlement?

A. Hinton Direct Exhibit 12 included both a "customer growth adjustment" and a "usage adjustment," and these two resulted in a substantial revenue adjustment. Per the Settlement, the "usage adjustment" (4,606,715 kWh) to test year sales that I included in my direct testimony was removed. This is appropriate because it is believed that the figures underpinning the usage adjustment were possibly skewed and/or exacerbated by reduced energy sales stemming from the COVID pandemic. As previously noted, the Settlement overall cost of capital, as well as with the withdrawal of the usage adjustment represents a reasonable middle ground between the original positions of the Public Staff and the Company. In addition, the agreement on the Settlement occurred in the context of various other compromises by both parties on other issues. Settlement on all this and all the issues referenced in my testimony are fair, just, appropriate, and reasonable both to the utility and to the ratepayers.

Q. Does this conclude your settlement testimony?

A. Yes, it does.

MR. FREEMAN: Thank you very much, Commissioner. At this time, Mr. Hinton is available for cross-examination and questions from the Commission.

COMMISSIONER KEMERAIT: The information I have, the only cross-examination of Mr. Hinton is from Appalachian Voices.

MR. MARGARIRA: Thank you, Commissioner.

CROSS EXAMINATION BY MR. MARGARIRA:

Q Good afternoon. Munashe Magarira, co-counsel on behalf of Appalachian Voices, just for the record. I'll try to cut down on this a little bit. Mr. Hinton, good to see you. So Public Staff originally proposed a rate of return of 6.07 percent?

A Yes.

Q And that rate of return was based on an ROE, so Return on Equity of 8.9 percent, cost of debt of 3.23 percent, and 50 percent equity to 50 percent long-term debt capital structure, correct?

A Yes.

Q Now, the Stipulation, of course New River and Public Staff, agreed to a new overall rate of return of 6.165 percent?

A Correct.
Q And that rate of return is based on an ROE of 9.1 percent, a cost of debt of 3.23 percent, and that same hypothetical capital structure, so 50 percent common equity to 50 percent long-term debt?
A Yes.
Q Okay. So you filed some testimony supporting the cost of capital and usage adjustment provisions of the stipulation on July 6. Is that right?
A June 6.
Q June -- settlement testimony?
A No. So you're right, forgive me. I have my dates wrong.
Q All right, yeah, no worries. Do you have that testimony in front of you right now?
A Yes.
Q When you're there, can you turn to page 4, lines -- I think it's -- if I have the cite right, it should be lines 58 through 59.
A Yes.
Q Can you read that out loud into the record?
A From 58 to 59?
Q On page 4 of your settlement testimony.

A "The Company and Public Staff have fundamentally different views of current market conditions and the current cost of capital."

Q Okay. Thank you. So, obviously, recognizing there's a stipulation in effect, would it be fair to say that it's your position that the Public Staff's original 6.07 percent rate of return proposal is reasonable?

A Yes, that's very reasonable.

Q Okay. All right. Moving on, so generally speaking, a Return on Equity should compensate a utility shareholder's fore -- foregoing -- sorry, alternative investments in comparably risky companies?

A That's a major principle.

Q So, basically, when we're thinking about that, the utility shareholders, they have an opportunity cost that's got to be compensated through an appropriate Return on Equity?

A When you're talking about publicly-traded companies, yes, that's exactly the case. That definitely does not directly apply to this case, though. We can go further into that, if you'd like to, but in my opinion, the methods I've used to come up with the opportunity to cost of capital still apply.

Q Okay. And just to confirm, I mean, obviously, you've already, kind of, predicted where I'm going with this line of questioning. New River ultimately is an operating arm or division of Appalachian State?

A I noted that in my testimony that any decision on the riskiness of this Company needs to consider that. And I believe I have testified that that's my position and I believe that is the case, and I've tried to adjust my recommended Return on Equity with that in mind.

Q Okay. Again, sort of touched on this already but just to, kind of, make sure that we're getting this into the record, ultimately, New River's capital financing needs, specifically their needs, how they finance their capital, that's going to be satisfied through debt financing and their retained earnings?

A Largely so. I'm sure that's how the Company over time does that, yes, you know, with the Company. Again, they're not an investment utility. Accept and understand, that investors, actually the

State of North Carolina. And a simple point I'd like to get on the record now, because it may be the best time to do it as such, is that even though it's owned by the State of North Carolina, I don't believe that Mr. Hoyle's recommendation of a 6 percent, 6.25 Return on Equity is appropriate for this Company because he recognizes as the Return on Equity, in his mind, I believe, is equivalent to the cost of debt. I don't see that.

The Company needs a return, calling the equity cushion, a generator of spare funds available to do -- handle such things that we've recently seen with the cost of natural gas and the price of purchase power when it doubled from four and a quarter, whatever, to over 9 cents per kWh. They had to use borrowed funds to pay for their power. Somewhere when they went through a substation, they had to raise -- had a general revenue bond through Truist to finance that substation yard, so that's a large capital expenditure. They still have to do that. They still have those operations and they have to finance such things. And they have to keep a debt service ratio like 1.25 with those Truist lines but they also have an opportunity cost. And here's the concept and I don't want to get too theoretical here, but it's still an asset. It's still a regulated opportunity. It's a business. They could sell that business tomorrow.

BREMCO, which is a nearby cooperative, has this arrangement where they actually serve the hospital, and the hospital's located in the Town of Boone. When we went on our tour of the facilities, I saw the hospital, nice, new, big addition, a serious amount of power load that they would love to serve, but through whatever reason, contractual reason of arrangements, it's served by BREMCO. The point I'm bringing that up is that BREMCO is probably a ready and able buyer, willing buyer of this service territory. So is Duke Energy. If they can't make their risk adjustment Returns on Equity, Mr. Jamison would be -- maybe it would be wise to tell the Board of Governors. Maybe we can sell this utility, and best proceeds, and trust and continue to fund our endowment and other funds at a more enhanced rate without taking the risk of operating utility. So they still have an opportunity cost. They still -- they could sell this Company, if it doesn't generate returns equivalent for its riskiness, and I believe the only way to appropriate the risk adjustment rate of return is in my testimony as I've identified using the DCF risk premium analysis.

Q Of course there's no proposed sale obviously being contemplated by New River?

A That's correct. And as you asked me, investors look at the opportunity cost of capital. An opportunity cost does not necessarily depend on an actual transaction. It is, again, a theoretical cost. It's what divides accounting and economics. It's largely the concept of opportunity cost, because an accountant would say X, an economist says Y. And your Y's based on an opportunity cost of the next best opportunity of that capital. And one could construe that if this utility does not earn its required Return on Equity, they, too, would be better off being sold.

Q Understood. Let's go back to something you said earlier, and I think we're in agreement here. Obviously, at the end of the day, any cost of capital analysis is going to have to, in some way, account for New River's unique status as a state-run utility. Obviously, the parties are in disagreement as to how you would do that, but you've got to account for it in some form or fashion.

A I agree with you. I said that in my testimony that it's a fact, can achieve, recognize.

Q Would it be fair to say that the main way in which your cost of capital analysis accounts for this unique status is through a -- and I'm quoting you here. **This is the bottom of page 27 of your direct testimony.** It's around line 17, and I'll just direct you to it. I'll just read it out loud. ***In my opinion, these factors justify an allowed return on equity that is at the lower end of the range of reasonableness.*** Is that fair?

A Yes, that's fair.

Q Okay. However, your DCF analysis and your regression analysis reveal that 8.49 percent

Return on Equity -- and I'm referring here to page 27 of your direct testimony, lines 3 through 5, so just -- if you skip just further up there, your DCF analysis reveal that the reasonable range includes 8.49 percent. Is that right?
A I'm sorry. What page are you reading that from?
Q Same page, 27, lines 3 through 5. So it should be the same page that you're on.
A Okay.
Q Yeah. It's your direct testimony.
A I am embarrassed. I'm missing -- for some reason 27, 28 pages --
MR. FREEMAN: May I approach?
A May I borrow that, yes. Can you repeat your question? I'm sorry.
Q Yeah, no worries. So, again, this is lines 3 through 5. You would agree that 8.49 percent Return on Equity would be within that sort of band of reasonableness?
A Well, there's -- I'm not saying it would not be unreasonable what you just said, but also I had a risk premium analysis that said 9.76 with a reasonable estimate for the cost of equity.
Q Understood. So if you can indulge me a little

bit, and I'll be brief, I just want to go over, sort of, the basics of the Discounted Cash Flow analysis, just real quick. So at bottom, what the DCF analysis seeks to do is it seeks to determine how much money an investor would make from an investment in the future, adjusting for the time value of money.

So, basically, fundamentally, as I understand it as a lawyer, it's this idea that money that you've got in your pocket today is worth more than money that you'd have at some future point, so you've got to adjust for that. Is that --

A Well, you do have to do impressive ads. That's what you, again, have to --

Q Yeah.

A But I think another way to look at a DCF model, it looks at -- it -- by using dividend yields plus growth element, you can estimate the required Return on Equity for someone to give or invest into a utility stock; forego that consumption of that stock, forego investing into other stocks, and that's the rate of return that he does that with the expectation of receiving over the infinite time period rising. The long-term would be the practical speaking.

Q Got you. And so for purposes of this proceeding, when you're doing cost capital analysis, the return that you're, sort of, thinking about with regards to, you know, what that stream of money would be in the future, for purposes here, it's going to be that future stream of dividends that you would get. Is that right?

A Yes. I mean, that's how the model works and -- yes.

Q Okay. And so when you're running that analysis, at least initially, what you're solving for is the price of that stock, at least initially. Is that right?

A Well, that's a part of the dividend yield. You put -- you basically do dividend over the next 12 months divided by a price, plus a growth rate, and that gives you a rate of return that you think it equates the cost of capital.

Q Right. And so, actually, you pretty much jumped to right to where I was going to go. So as I understand from what you said, when you're solving for the cost of capital, which is "K" in that DCF analysis, what you want to do is you want to divide expected dividends per share by the price, and you take that value which you refer to as dividend yield, and you add the growth rate to that dividend yield. Is that right?

A Yes, to get the expected return.

Q So it would be improper to add that growth rate to the price in the denominator. You'd add it to the dividend yield as opposed to the --

A Correct.

Q Okay, perfect.

A And as I've -- yes.

Q All right. Let's move on. So page 22 of your direct testimony and Exhibit 4 of your direct testimony, you provide the peer group and the factors you used to identify that peer group in calculating your return on equity?

A Yes.

Q So you use -- and let me jump there for my own benefit. Just bear with me real quick. So you use a couple of -- actually, it's four factors. You use Safety Ranks, Beta co -- I'm probably mispronouncing it but Beta coefficients, Earnings

Predictability Rank, and the S&P Bond Rating.
A Correct. They're there widely available through investment risk metrics that I believe investors look at. Now, it's always hard to know for sure what is the metrics that they construe in their minds when they develop their own investment expectations on risk of return but I believe these are good indicators of risk.
Q Got you. But, again, you know, New River has, you know, outside financing but it doesn't issue stock.
A That's true but at this point, I just want to say briefly that the use of a comparable group for a company that does not trade stock, is, I hate to say, nothing new under the sun. My first case which was Heinz Telephone back in 1989, I believe, or '87, it was not traded. It was owned by Alltel Corporation but it was not traded. You know, it was independently owned. It was later bought out by Alltel, but at that time, I had used a comparable group of telephone companies to develop a comparable cost of equity for Heinz, as I'm doing here today for New River.
Q Got you. All right. Let's skip a little bit.

So on page 27 of your direct testimony, again, beginning on line 8, you state that New River confronts operational risks similar to a distribution-only electric utility.

A Yes. One of the things I did going back to like 10 years of annual reports, and I went to their cost for fixed investments, and their standard operating expenses, and their net income, and tried to do the ratio analysis on how that's been growing. You know, their customer growth's growing a little less than 2 percent per year. There's some growth in that Company.

Q So another thing that you did, and this is Exhibit 7 of your direct testimony, you provided a list allowed ROEs for distribution-only utilities. Is that right?

A Yes, I did.

Q Okay. But the peer group that you used for your, sort of, core analysis, that peer group includes some vertically integrated utilities. Is that right?

A Yes, I think they are. The problem there is there's not any actively-traded companies that are pure play in the sense where they're just distribution companies, so I was limited on where I can look to employ the DCF model.

Q Okay.

A So one could argue that the DCF model could possibly overstate the cost of equity because it's looking at vertical regulated ones, which are more risky than distribution ones, and I accept that, but I believe that if there is any overestimation, it's within our margin of error, and I think my judgment, kind of, has that in mind.

Q Moving on in your DCF analysis, in calculating specifically, I think, a number of things, you rely on, sort of, dividends as we mentioned at the -- sort of at the front, we, sort of, said, you know, when you're thinking about DCF analyses, you've conducted it, we're thinking about streaming dividends, right?

A Right. It's the -- you have to -- you have to use -- well, the Gordon Model calls for expected dividends in the next 12 months, and Value Line -- all -- well, publishing their summary editions, the expected dividends for ESOC over the next 12 months. Well, I just grab that number off their summary report --

COURT REPORTER: I'm sorry. Could you repeat your sentence?

THE WITNESS: Yeah.

COURT REPORTER: Your last sentence?

THE WITNESS: Okay.

A The Gordon model for the DCF requires the dividend yield to be the expected dividend yield over the next 12 months, and Value Line Investment Survey prints out every week in their weekly summary edition, and so I just grab that, as I mentioned in my testimony, and it's an expected dividend, because, as you know, dividends, depending on the timing of when they're issued and increased by a company or decreased by a company, can affect the 12 months, so I look to -- rather than -- there are other ways to make that adjustment, to get a D-1 expected dividend yield, but this seems to be a very straight-forward method that I use.

Q But, again, New River doesn't have equity investors, so it doesn't issue dividends?

A That's correct. I mean, it does pay the endowment fund and the other graduate fund.

Forgive me, I can't remember his last name, and that is a form of a dividend to -- potentially. I don't necessarily see it as a potential dividend because it's not obligated to any particular end user. They just give it as a gift, but the source of those funds come from the profit efforts on New River Power and Light. I accept that.

Q So, I mean --

A But I don't necessarily call it a dividend though. I see the similarities.

Q I think we're in full agreement that they're definitely not dividends. And so given that New River does not issue dividends, when we're thinking generally about DCF analysis, when there is a reduction in dividend growth or a suspension in dividend payments, from the perspective of an equity investor, that's a risk that that equity investor might bear or experience. Is that fair?

A Without a doubt, and the price over time reflect that decreased expectation.

Q And that would be for a utility that has that, sort of, you know, equity investor or that risk. That's a risk that would ultimately impair that utility's ability to attract capital?

A Right, and possibly -- and rate -- in fact, the simple way of how it often works is companies will issue new equity at certain times every five years or -- it's not done every week or even every year but periodically, they'll issue new equity. If the stock price is high, they get a lot more money. And then, of course, we all know about things like dividend employee stock ownership plans and other ways that the utility will -- is better off with a high stock price because it does provide capital to the entity through, again, the employee stock ownership plans, other dividend investment plans, and of course the issuance of new common equity.

Q Got you. Okay. So I think because New River does not have equity investors, and even if they did have investors, that's not a risk that they bear. Given that that is maybe not a comparable thing they can compare it between the two utilities, your DCF analysis still relies on dividend growth rates and utilities with dividend-related risks, even though we both are in agreement that New River does not issue dividends?

A Correct, but I was asked to testify on the required rate of return for this Company, so my starting point is what will be the required rate of return for what I conceive to be -- perceive a conservative risk utility, and that's why I picked the four screening elements that I have. From that, that was a bit of market insight that I use as evidence to base my opinions on in my recommendations to this Commission.

Q Okay. So in calculating the dividend yield and expected growth rate component of your DCF analysis, you relied exclusively on Value Line data?

A No. I also looked -- the earnings per share numbers come from Yahoo, which is -- they aggregate earnings, consistent forecast models. There's a column there in the DCF analysis called Earnings, Forecast, Earnings.

Q Okay.

A So, yes, there are two main sources. The Value Line data is the dominant one, but also look outside for other earnings, consensus earnings reports.

Q Okay. Taking into account that you also did a Yahoo analysis for purposes of calculating, or I guess, proposing your return on equity, fundamentally, it's, sort of, the only checks that would have been on the Value Line data, would be the Yahoo data and the regression analysis that you conducted?

A Those are my two methods principally I employ, you are correct.

Q Okay.

A I mean, obviously, I'm aware of what's going on in the financial markets as I've tried to allude to in my testimony, but that's a permanent chain. Then, of course, there's always the exhibits you spoke of where our virtual resource associates or S&P global publishes the required returns on equity that have been approved by other Commissions over the years. And I looked at that, and as you see, the last 12 months ending March 31st -- March -- March of this year, was 9.13, I believe, and so that's on an exhibit there and that only includes the 9.8 award for 2023, which was one single case, and in my mind, had to discount that because the other years, there is multiple cases that represent an annual time period.

Q All right. I'm just going to have a couple more questions here, so let's talk about the regression analysis that you conducted on page 25 of your direct testimony, beginning at line 3. You, sort of, described that regression analysis. And as I understand it, it's, sort of, trying to determine or analyze a relationship between allowed returns and A-rated utility bonds. Is that right?

A Correct.

Q Okay. So this regression analysis you note -- and this is starting on line 10. It's that same page. It attempts to quantify the risk premium that equity investors require to invest in the utility stock instead of bonds?

A Yes.

Q Okay. Further down, line 15, same page, you note that -- and I'm quoting you here. *The use of utility bond yields is preferred over the use of United States Treasury yields because it allows examination of the added risk premium associated with an investment in electric utility common* *stocks.*

A Yes. I'm just making a little informational sentence. Other people employ the risk premium model and commonly people use Treasury bonds as their bond measure. And I think it's -- like I said, it removes an error of possible error when you limit the thought to public utility bonds, and plus my testimony that I issued back in '93, and ever since then, the model does attempt to look at what is the additional return required to go from a bond to a stock, and so staying with the same entity, type of entities, which is what the public utility's index is comprised of. There are six or eight different utility bonds there that are being traded in the secondary market, and that's how they construct that index.

Q So just to be really clear on this, this analysis is, sort of, trying to determine what additional risk equity investors bear by investing in the stock as opposed to a bond?

A Correct.

Q Okay.

A Utility stock, a utility bond.

Q However, to the extent New River even has investors, they wouldn't have that option between investing in New River stock or bonds?

A That's correct.

Q The only option would be to invest in debt?

A I mean, to invest in New River, of course Appalachian State University, i.e. the State of North Carolina.

Q Okay. All right. Last couple questions. You propose a 50/50 hypothetical capital structure?

A Yes.

Q You note on page 16 of your direct testimony -- and let me try and find the specific line number so you can read along with me. Just give me one second. I'll just read this out to you and, you know, obviously, you can agree to it or not. So you write, *The use of a hypothetical capital structure is appropriate because of the absence of publicly-traded companies with similar capital structures.* And this is actually, I believe, lines 3 through -- well, it's lines 3 through 7 really, so I'm, sort of, paraphrasing, but is that a fair representation of your testimony?

A Yeah, and allow me to take a moment here. There was a similar case before I testified before the

Commission. It's North State Water. They had a capital structure of roughly 70 or close to 80 percent debt. Now, I have amazing respect for Bill Grantmyre, and I know we all do, but he taught me, persuasively tried to talk me into using the actual capital structure in my testimony because he's a consumer advocate. So am I, but I have to testify before you folks. He sits over there. The point of the matter is, is that that was extreme capitalization that was in the public's favor but it was unreasonable. I could not determine a cost rate for equity for an investor who would buy stock that has that much debt leverage because there's so much risk there. The converse is true of this case. It's hard to find an equity investor in utilities who will say I'll invest in a company that has only 35 percent debt, because most utilities out there are in the ballpark of around 50 percent to 55 percent to 60 percent, maybe as low as 45 percent, but those are the ranges of capitalization ratios that you see in the marketplace. So I can't testify to the Commission what's the appropriate cost of equity when I'm dealing with a capital structure that's, pardon my language, whack.

Q You've had a chance to review New River Witness's Randall Halley's direct testimony?

A Yes.

Q And you've obviously been with the Public Staff for a very long time, so you're aware that the Commission has approved New River's actual capital structure in the past?

A I don't recall that. I think I worked on the last rate case in 2017, and I think we used the hypothetical capital structure there too.

Q Subject to check, would you agree the Commission approved a 93.58 percent equity to 6.42 percent long-term debt capital structure in the E-34, Sub 32 proceeding?

A Which year was that case may I ask?

Q '97.

A '97?

Q I believe.

A Okay. I was thinking about 2017. I testified in 2017. Possibly that was, but I did not work on that case, to be honest with you. I did not.

MR. MAGARIRA: That's fine. No further questions.

COMMISSIONER KEMERAIT: Redirect from the Public Staff?

MR. STYERS: As tempted as I am, I will not ask any questions given the interest of time.

COMMISSIONER KEMERAIT: Mr. Styers, I don't think you've reserved any cross time.

MR. STYERS: Other than noting at the bottom of the -- of the -- that we were reserving in the event it needed to be clarified for the support of stipulation, I don't think it needs to.

COMMISSIONER KEMERAIT: So no cross-examination from New River?

MR. STYERS: Correct.

COMMISSIONER KEMERAIT: Redirect from the Public Staff?

MR. FREEMAN: One moment, Commissioner. Thank you. We don't have any questions.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q Okay. Mr. Hinton, I just have one question that actually comes from Commission Staff, and this is in regard to the usage adjustment that you discuss in the settlement, and this is on page 5. You may not even need to turn to it but as part of the Stipulation, New River and the Public

Staff agreed to eliminate the usage adjustment that you had proposed in your direct testimony. And can you explain whether New River and the Public Staff agreed to the Public Staff's customer growth adjustment that you had proposed in your Exhibit 12 and whether the customer growth adjustment was revised in the Stipulation as well.

A My understanding is that the customer growth adjustment remained intact. And I can't say that -- I have no knowledge of it being adjusted in the stipulation either, so I would testify, to my knowledge, it remains in tact. And as you said, the usage, adjustment was withdrawn, and I think the reason I noted for the adjustment was seemingly excessive and on reflection, and it was easily to be -- it was something that I think was reasonable to negotiate away.

Q And do you know what the final calculation for customer growth is then?

A It'll have to be a late-filed exhibit. I don't know. I mean, I have -- no, I don't.

Q I can ask the Company that question.

COMMISSIONER KEMERAIT: Okay. Chair

Mitchell.

EXAMINATION BY CHAIR MITCHELL:

Q Mr. Hinton, very quickly, you heard my questions to Mr. McLawhorn. Do you have anything to add in response to his responses to my questions regarding exposure of New River customers to fuel price volatility?

A Yeah, and hedging. I'm afraid the best I can say I'm no more smarter than James McLawhorn.

Q All right. Okay. Cost of gas has been revised to $5.00, I think, in base rate, $5.00 and change. To my recollection, Public Staff didn't take issue with that in testimony or in the Settlement. And, so, can you just react to the $5.00 in base rates and are you comfortable with that?

A That's certainly not my testimony, so please accept whatever I say as just an outsider looking in, but, you know, I know the cost of gas is down. I mean, you know, the spot price of gas is around $3.00, if I recall correctly. And, so, now whatever the time period of purchasing, they will be purchasing, I can't say, but if James McLawhorn does not have an issue with that, then

I support his testimony.

Q I didn't ask James about that specific question but I'm not hearing you take issue with it at this point?

A No, no, I wouldn't.

Q Okay.

A I mean, because in the PGA -- I mean the gas cost adjustment process, even though I've been here forever, it seems like, I'm a little rusty on how the mechanism fully works every time. So, I mean, I don't know how much of a lag effect is in there and I haven't reviewed the contract with Carolina Partners.

Q All right. And can you refresh my recollection as the -- and then we had a PPA adjustment recently. What is the cadence? What's the typical cadence of those PPAs? Is it annually?

A To be honest, I cannot testify to that.

Q Okay. All right, Thanks, Mr. Hinton.

A It's not me.

COMMISSIONER KEMERAIT: Okay. Now, we'll move to questions on Commission questions. I apologize. Commissioner Clodfelter has a question.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. Hinton, I listened to your testimony and I'm just curious about something. This Commission's authority to set the rates for this entity, it's supposed to set a rate only for the sale of surplus power that the entity has beyond the needs of the institution that owns it. That's a little bit different from being in the general business of selling power to the public, and that's why it's not a public utility. Our authority comes from a statute other than Chapter 62. Is it the Public Staff's position that we have to follow exactly the same ratemaking methodology for this entity that we use for entities that are subject to the jurisdiction of Chapter 62? Is that the Public Staff's position?

A I'm waiting for my attorneys to jump in.

Q Excuse me sir? I just didn't hear you.

A I'm waiting attorneys to jump in.

Q Well, let's leave it as a rhetorical question then and maybe they'll want to address it in their briefs.

A My common sense response is that you should regulate them like you regulate any other utility because the customers expect that.

Q The General Assembly could have told us to do it that way, couldn't they?

A They could have, but --

Q And they didn't, did they?

A When was this legislation written I'd ask? And that was when maybe Boone was a small mountain town. Now Boone is a large metropolitan area, well I imagine.

Q That may be it. Let's just leave the question at that --

A I'm sorry.

Q Maybe your counsel will address it in their brief.

A Yeah, maybe so.

COMMISSIONER KEMERAIT: Okay. Now, we'll go to questions on Commission questions starting with Ms. LaPlaca.

MS. LAPLACA: None. Thank you.

COMMISSIONER KEMERAIT: Appalachian Voices?

MR. MAGARIRA: None from Appalachian Voices.

COMMISSIONER KEMERAIT: Okay. New River?

MR. STYERS: Thirty seconds.

EXAMINATION BY MR. STYERS:

Q In response to Mr. Clodfelter's -- Commissioner Clodfelter's questions, were you involved in the rate cases for Western Carolina University in 2016 and 2020?

A Yes, I was.

Q And the New River rate case, the last New River Light and Power rate case in 2018?

A '17.

Q '17? And in each of those cases, was there assumed capital structure of 50/50?

A Correct.

Q And was there then assumed return on equity and cost of debt in those three cases?

A I can't say -- when you say "assumed" it was --

Q I mean, a rate of Return on Equity, return on equity, and cost of debt.

A Correct, it was a rate of Return on Equity and debt. And the rate of Return on Equity was determined and some of the math I've done today, and -- but I cannot remember precisely their case or how much of a change from what I prefiled versus what was actually approved or submitted for approval.

Q So the ratemaking that the Commission undertook in those three cases are consistent with the Public Staff's testimony in the Stipulation of this case?

A Yes.

Q But the overall rate of return in this case would actually be -- it would be the lowest of those other rate cases I've just discussed, is it not, the overall rate of return?

A Yes, and I would say it's largely due to the cost of debt coming down.

MR. STYERS: No further questions.

MR. FREEMAN: Thank you, Commissioner. I don't know that I have a question but if the Commission would -- the customer growth adjustment and customer use adjustments are found at Hinton Exhibit 12 which is the final page of his testimony, if that's, sort of, the response to one of the Commission's questions -- Commissioner's questions.

COMMISSIONER KEMERAIT: Thank you. Seeing no further questions on Commission questions, does the Public Staff have a motion that you would like to make?

MR. FREEMAN: Thank you. Presiding

Commissioner, the Public Staff would respectfully move that Mr. Hinton's 12 direct testimony exhibits and single settlement testimony exhibit, and two appendices found in his direct testimony be entered into the record and bear the same identification as they were when prefiled.

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

(WHEREUPON, Hinton Exhibits 1-12, Public Staff Hinton Settlement Exhibit 1, and Hinton Appendices A and B, are received into evidence.)

MR. FREEMAN: Thank you.

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

THE WITNESS: Thank you.

COMMISSIONER KEMERAIT: So this takes us, I think, to the end of the Intervenor's witnesses and testimony, so it is now witnesses from New River.

MR. DROOZ: New River Light and Power calls Ed Miller to the stand.

COMMISSIONER KEMERAIT: Good afternoon, Mr. Miller.

MR. MILLER: Good afternoon.

EDMOND C. MILLER;

having been duly sworn,

testified as follows:

COMMISSIONER KEMERAIT: Thank you.

DIRECT EXAMINATION BY MR. DROOZ:

Q Would you state your name and business position and address for the record, please.

A My made is Edmond Chris Miller. I am the General Manager for New River Light and Power located at 146 Faculty Street Extension, Boone, North Carolina.

Q And did you cause to be filed seven pages of direct testimony with two exhibits at the time the Application was filed in this case on December 22nd, 2022?

A I did.

Q Okay. And did you cause to be filed 17 pages of rebuttal testimony with two exhibits on June 23rd of 2023?

A I did.

Q And did you also have filed a one-page summary of your direct testimony on July 7th and a one-page summary of your rebuttal testimony on July 7th?

A I did.

MR. DROOZ: We would ask that the prefiled testimonies be incorporated into the record as if orally read from the stand and that the exhibits be identified as marked.

COMMISSIONER KEMERAIT: And Mr. Drooz, for clarification, my notes show that Mr. Miller's rebuttal testimony consists of 19 pages, so let's just make sure that we have the correct number of pages.

MR. DROOZ: I'm going to need to check on that, what it includes.

COMMISSIONER KEMERAIT: I have 19 pages and two exhibits.

MR. DROOZ: If you can give me just a second. You know, my printout copy here has 17 pages.

MR. STYERS: Yes, us too.

COMMISSIONER KEMERAIT: Okay. So Mr. Miller's direct testimony filed on December 22nd of 2022 consisting of seven pages, and his rebuttal testimony filed on June 23rd of 2023 consisting of 17 pages, will be copied into the record as if given orally from the stand. The two exhibits attached to the direct testimony and the two exhibits attached to the rebuttal testimony will be marked for identification purposes as prefiled.

(WHEREUPON, EM-1, EM-2, and Miller Rebuttal Exhibits 1 and 2 are marked for identification.)

(WHEREUPON, the prefiled direct and rebuttal testimony, and summaries of Edmond Chris Miller is copied into the record as if given orally from the stand.)

APPALACHIAN STATE UNIVERSITY
DBA NEW RIVER LIGHT AND POWER COMPANY
DOCKET NO. E-34, SUB 54

DIRECT TESTIMONY OF EDMOND MILLER

ON BEHALF OF
APPALACHIAN STATE UNIVERSITY
DBA NEW RIVER LIGHT AND POWER COMPANY

DECEMBER 22, 2022

Q: PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A: My name is Edmond C. Miller. I am the General Manager of New River Light and Power Company ("NRLP"), which is an operating unit of Appalachian State University ("ASU"). My business address is 146 Faculty Street Extension, Boone, North Carolina 28607.

Q: DO YOU HOLD ANY PROFESSIONAL REGISTRATIONS?

A: Yes. I am a registered professional engineer in the States of North Carolina and South Carolina.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: The purpose of my testimony is to provide an overview of NRLP along with key facts leading to the need for the rate increase requested in this proceeding.

Q: PLEASE EXPLAIN THE STRUCTURE OF NRLP IN RELATION TO ASU.

A: NRLP was started in 1915 by Dr. Blanford Dougherty, President of the Appalachian Training School (now ASU), who commissioned the building of Boone's first electric generating plant. NRLP has been serving Appalachian State University and the Town of Boone since that time. NRLP is an operating unit of ASU. NRLP maintains a staff of 31 employees, including both administrative and operating personnel. Other services required to operate the utility are provided by ASU. These services include legal, human resources, information technology, and administrative supervision (facilities management and financial services).

While ASU owns NRLP, it is also the largest consumer of power on the NRLP system. NRLP also serves other customers in the Town of Boone.

As a utility serving the public, in addition to ASU, NRLP is subject to regulation of its rates and service by the North Carolina Utilities Commission ("NCUC"). NRLP submits reports and updates of its Purchased Power Adjustment ("PPA") and must receive NCUC approval for any changes in its base rates.

Q: HOW DOES NRLP COMPARE TO OTHER UTILITIES IN THE STATE OF NORTH CAROLINA?

A: NRLP is similar to a number of municipal utilities in the State, serving primarily residential and commercial load, but only limited large commercial load, in and around a single municipality. Like many municipal systems, NRLP is distribution-only. ASU made up approximately 21.8% of energy use on the NRLP system in 2021. NRLP has a total of 8,882 metered customers and had a peak load of approximately 43.9 MW in 2021.

Key performance reliability indicators are significantly more favorable than other utilities in the state, including the System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency ("SAIFI"). Exhibit EM-1 provides a summary comparison of these reliability indicators.

NRLP's rates are also favorable when compared to other utilities in the State. Each year, the United States Department of Energy, Energy Information Administration ("EIA") publishes a comparison of rates for utilities in the state. For the last two years, NRLP has been shown to have the lowest residential rates in the state. NRLP has historically maintained a status of one of lowest cost providers based on the EIA analyses. Based on 2021 EIA data, NRLP was the lowest cost provider for residential consumers in North Carolina. This comparison is shown in Exhibit EM-2.

While NRLP compares favorably to other utilities in the State, it also has significant differences that create challenges in its operations.

Q: WHAT ARE THE SIGNIFICANT DIFFERENCES BETWEEN NRLP AND OTHER UTILITIES IN THE STATE?

A: While NRLP is significantly smaller than investor-owned utilities in the State, it is one of only two state-run electric utilities that is subject to NCUC regulation. Municipal and cooperative electric systems, which are more comparable in size and operations, are not subject to NCUC regulation. While this, in and of itself, is not problematic, the regulatory process creates a significant lag in cost recovery, particularly with respect to obtaining approval for necessary rate increases.

Another significant difference is the isolation of NRLP on the transmission grid. While most utilities in the State are directly interconnected with a transmission-providing investor-owned electric utility, NRLP is isolated and is only interconnected with Blue Ridge Electric Membership Corporation ("BREMCO"). NRLP has negotiated a new wholesale power supply arrangement with a merchant plant generator. That power will be delivered to NRLP through transmission lines of Duke Energy Carolinas, LLC, and then through BREMCO lines. As a result of this new wholesale power supply arrangement, NRLP negotiated an unbundled transmission rate with BREMCO.

Q: WHEN WAS NRLP'S LAST BASE RATE CASE BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A: While NRLP files annual updates to its PPA, its last filing to change base rates was made in 2017. That case was NCUC Docket E-34, Sub 46.

Q: WHAT ARE SOME OF THE FACTORS THAT HAVE LED TO THE NEED FOR A BASE RATE INCREASE AT THIS TIME?

A: Since the last rate case, several factors have combined to necessitate NRLP's request for a base rate increase at this time.

1) Capital Infrastructure Investments - NRLP has invested in advancing technology and upgrades for its system. Some of the major projects include:

   a. The construction of a new campus substation. This new substation was required due to upgrades BREMCO made to their transmission system. BREMCO has been replacing its older 44 kV systems with 100 kV lines. For NRLP to continue to receive power at the ASU campus delivery point, it was necessary to replace this substation with 100 kV equipment;

   b. Purchase and installation of a new supervisory control and data acquisition system ("SCADA"). The previous SCADA system was outdated and would not work with NRLP's new AMI system;

   c. Replacement of overhead distribution lines with an underground system in residential areas experiencing higher than average outages due to tree canopies and wildlife;

   d. Renovation and expansion of NRLP's warehouse office building to provide additional space for the new AMI metering shop and office space for field staff. Modifications were also made to comply with ADA standards and provide heating and air conditioning to workspaces that previously had no environmental controls; and

e. Rebuilding NRLP's laydown yard used for storing of large inventory items such as poles and transformers. This was a complete rebuild of previous structures that had reached the end of their useful lives

2) Unrelated Business Income Tax ("UBIT") – Based on a 2019 KPMG audit for ASU, it was determined that NRLP should pay income tax on electric revenues received from retail customers other than ASU and the Town of Boone. This is a new expense that was not accounted for in NRLP's 2017 rate case. Therefore, base rates need to be adjusted to recover this tax expense.

3) Increased Purchased Power Costs - Due to the extraordinarily volatile natural gas market within the past year, NRLP has incurred drastic increases in its purchased power costs. These increases have caused significant cash flow issues for NRLP. This year's increase in natural gas costs required NRLP to file a midyear PPA to assist with some of the additional purchased power costs. NRLP also had to take a $7 million line of credit to cover the remaining cash flow issues for this year. Correcting the amount of purchased power costs recovered through base rates will relieve some of this cash flow issue.

4) Inflation and Salary Increases – NRLP has also experienced increased costs in its operations, including three rounds of salary increases for its employees necessary for recruiting and retention.

Q: WILL NRLP OFFER A NET BILLING RATE FOR ITS CUSTOMERS WITH SOLAR GENERATION?

A: Yes. NRLP is proposing a Net Billing Rate for its retail customers that would allow any excess energy generated to be placed back on NRLP's distribution system. This proposed Net Billing Rate was developed based on the criteria established in N.C.G.S. § 62-126.4.

Q: WILL NRLP OFFER A TIME OF USE RATE FOR ITS CUSTOMERS?

A: Not at this time, but NRLP is seriously considering the option of a time of use rate for its residential customers in the near future. The intent would be to offer capacity and energy charges at different times of the day that correspond with NRLP's purchased power costs. This will require more extensive use of NRLP's AMI metering and billing system than is currently possible. NRLP will focus on developing the necessary functionality over the next two years, and after that will be able to propose a time of use rate.

Q: PLEASE INTRODUCE NRLP'S OTHER WITNESS IN THIS PROCEEDING.

A: NRLP's other witness is Mr. Randall Halley of Summit Utility Advisors, Inc. ("Summit"). Mr. Halley addresses NRLP's revenue requirements, rate of return, cost of service, and rate design.

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A: Yes, it does.

SUMMARY OF DIRECT TESTIMONY OF EDMOND MILLER

ON BEHALF OF
NEW RIVER LIGHT & POWER

DOCKET NO. E-34, SUBS 54 & 55
JULY 10, 2023

New River Light & Power is an operating unit of Appalachian State University. The utility started in 1915 to supply electric power to the educational institution. The surrounding community had no electric service, so New River extended lines to provide power in the Town of Boone.

New River is a small utility. There are approximately 8,882 metered customers. We have 31 employees. Some services are provided to New River by Appalachian State University staff.

New River only provides distribution service. We buy power under contract with Carolina Power Partners. That electricity is delivered to our substations over the transmission lines of Duke Energy Carolinas and the distribution lines of Blue Ridge Electric Membership Corporation.

The present rate case is driven by new capital investments including:

- A new campus substation
- A new SCADA system
- Replacement of overhead lines with underground lines where there were high outages
- Renovation of the New River warehouse
- Renovation of the New River laydown yard

In addition, we have had increased expenses due to Unrelated Business Income Tax, purchased power costs, and inflation and salary increases.

Another feature of the New River rate request is that we propose for the first time a Net Billing Rider for customers with solar generation that wish to use their renewable energy.

Finally, I am proud of the outstanding service provided by New River. New River outperforms other utilities in North Carolina on the SAIDI and SAIFI reliability factors. At the same time, data from the U.S. Energy Information Administration shows that New River has the lowest residential electric rates in North Carolina.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-34, SUB 54
DOCKET NO. E-34, SUB 55

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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	)))))))))))))	**REBUTTAL TESTIMONY OF** **EDMOND MILLER** **ON BEHALF OF NEW RIVER LIGHT AND POWER**

June 23, 2023

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

A: My name is Edmond C. Miller. I am the General Manager of New River Light and Power Company ("NRLP"), which is an operating unit of Appalachian State University ("ASU"). My business address is 146 Faculty Street Extension, Boone, North Carolina 28607.

Q: What is the purpose of your Rebuttal Testimony in this proceeding?

A: The purpose of my testimony is to respond to certain issues and recommendations raised in the pre-filed testimony of the Public Staff and Appalachian Voices in this rate case.

Q. Which Public Staff recommendations do you accept on behalf of New River Light & Power?

A. NRLP accepts the following recommendations made by Public Staff witness Jack Floyd.

1) Mr. Floyd's testimony stated NRLP should closely monitor the credits accumulated, consumption patterns, revenues, and costs related to the proposed Schedule NBR and file an annual report of net metering/billing activities by March 31 of each year. In subsequent discussion, NRLP proposed, and the Public Staff agreed, that this annual report could be filed in conjunction with each Purchased Power Adjustment Clause (PPAC) proceeding for NRLP.

2) Mr. Floyd recommended that Schedule NBR should be amended to include the following statement: "Any renewable energy credits (RECs) associated with electricity delivered to the grid by the Customer under Schedule NBR shall be retained by the Customer." This revision is shown in Miller Rebuttal Exhibit No. 1.

3) Mr. Floyd recommended that there should be a review of the proposed design of Schedule NBR and re-evaluation of the energy resetting process and the SSC in five years. NRLP agrees, and further notes that since the energy credit is the retail rate, it should be adjusted as appropriate with every PPAC filing. The Public Staff agreed that it would be appropriate for NRLP to make this adjustment in each PPAC filing.

4) Mr. Floyd recommended that for the proposed PPR rate, the energy credit should be based on total system costs rather than just residential class costs. NRLP agrees and suggests that this calculation can be provided with the compliance filing after the Commission's final order, and then updated with each PPAC filing. The Public Staff is agreeable to these suggestions.

5) Mr. Floyd recommended that proposed Schedule PPR should be amended to include the following statement: "Any renewable energy credits (RECs) associated with electricity delivered to the

grid by the customer under Schedule PPR shall be retained by the Customer." NRLP agrees.

This revision is shown in Miller Rebuttal Exhibit No. 1.

6) Mr. Floyd recommended that after five years there should be a review of the proposed design of Schedule PPR. NRLP agrees, and also would review the PPR during the biennial avoided cost proceedings if appropriate.

7) Mr. Floyd sought clarification that the payment of any credit under Schedule IR should occur only in the event that the participant is able to curtail load at the time of the coincident peak. No credits will be paid if the participant is unable to curtail or if the curtailment does not align with the coincident peak. NRLP agrees to make this clarification in the proposed Schedule IR tariff.

This clarification is shown in Miller Rebuttal Exhibit No. 1.

8) Mr. Floyd recommended that NRLP should replace its current reconnection fees for customers who had been disconnected with a single fee that reflects only the administrative costs associated with the disconnection and subsequent reconnection of service. The current approved reconnection fee is $25.00 during regular working hours and $60.00 otherwise. After discussion, the Public Staff and NRLP have agreed that the new rate schedules should include an

$11.50 reconnection charge. This reflects the advantage of remote disconnects and reconnects with AMI metering technology.

This revision is shown in Miller Rebuttal Exhibit No. 1.

9) Mr. Floyd indicated that the Commercial Demand class should not receive a phase-in of its significant percentage rate increase at the expense of other rate classes to the extent proposed by NRLP in direct testimony. The Public Staff and NRLP have agreed to a revised rate design that balances the tension between the rate design principles of achieving customer class rate of return parity and not subjecting any rate class to an extremely large increase in one proceeding. The proposed allocation of the rate increase by customer class is shown in Halley Rebuttal Exhibit No. 1. I mention this in my testimony only because I am listing all the tariff revisions that NRLP agreed upon with the Public Staff, but Mr. Halley is the appropriate witness to respond to questions on the details.

Q. Which Appalachian Voices Recommendations do you accept on behalf of New River Light & Power?

A. NRLP accepts the following recommendation made by Appalachian Voices witness Jason Hoyle:

1) NRLP should consider adding a program focused on weatherization and building retrofits and upgrades, particularly for older less-energy efficient residential units. (Hoyle Testimony p 45) For

clarification, NRLP's consideration of a weatherization program will depend on availability of funding, and if funding is available, the program would likely be tied to financial need. If funding is available, NRLP would consider combining a weatherization program with complementary energy efficiency improvements including efficient lighting, smart thermostats, and other opportunities for simple and cost-effective efficiency gains. If sufficient grant funding becomes available, NRLP hopes to outsource the program to a third party with experience in addressing building energy efficiency retrofits and in providing low-income assistance, as NRLP does not have the staff resources to operate such a program in-house.

2) 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 No. 1.[1]

Q. Which Appalachian Voices Recommendation do you accept with modifications?

A. NRLP accepts the following recommendations, with the indicated modifications:

1) Mr. Hoyle recommended that NRLP should formally propose as limited duration pilots (i) heat pump and water heater rebate

[1] While I am presenting Miller Rebuttal Exhibit No. 1 as part of my testimony, any questions about the calculations underlying the rate schedules should be directed to Mr. Halley.

programs; (ii) EV charging infrastructure throughout NRLP territory; and (iii) installation of programable thermostats that may be controlled by NRLP at a customer's request. (Hoyle Testimony p 44) The NRLP modification is that such programs will only be proposed to the extent that grant funding covers the costs for NRLP. NRLP is at the stage of exploring funding opportunities; it would be premature and not financially feasible to formally propose programs at this time.

2) Mr. Hoyle recommended that 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. (Hoyle Testimony pp 44-45) The NRLP modifications are that NRLP will determine if a program of notifying customers of anticipated high demand periods can be implemented at reasonable cost, and if so whether there should be a control group to provide data on the behavioral program's effectiveness. Again, financial feasibility is the first step, so it would be premature to propose a program at this point.

Q. Which parts of Appalachian Voices testimony does NRLP not agree with?

A. NRLP witnesses Halley and Jamison address parts of the testimony of Appalachian Voices witness Barnes with which NRLP disagrees, and the Appalachian Voices cost of capital testimony. I have concerns about parts of the DSM/EE testimony of witness Hoyle.

Q. Please explain your concerns with the DSM/EE testimony of witness Hoyle.

A. Witness Hoyle implies that NRLP has violated the terms of its Stipulation with the Public Staff in the last rate case (Docket No. E-34, Sub 46.) (*See* Hoyle Testimony pp 33-35) In the last NRLP rate case, Finding of Fact No. 41 in the Commission's order of March 29, 2018, states:

> 41. The Parties have agreed 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, recognizing that NRLP may not implement energy efficiency or demand side management programs so long as it is a party to the Electric Service Agreement with BREMCO. The Parties have further agreed that NRLP should report its progress on this effort to the Public Staff within 180 days of the date of this order.

NRLP filed a report on its progress on September 27, 2018, in Docket No. E-34, Sub 46. That report stated NRLP was working to develop a prepaid service rider to take advantage of the AMI capabilities. Neither the Public Staff nor the Commission, nor any other party, indicated that the report showed inadequate compliance with the Stipulation. Subsequently, NRLP filed for approval of a prepaid service rider, the application was supported by the Public Staff, and the Commission approved a prepaid service rider in

Docket No. E-34, Sub 49. The prepaid service rate schedule was identified as a customer benefit enabled by AMI metering.

NRLP has also offered the Green Power rider as a sustainability option for its customers.

NRLP has not proposed a slate of DSM/EE programs because (a) it does not have the staffing resources to develop and administer such programs in-house, and (b) it does not qualify for the DSM/EE cost recovery mechanisms available to other utilities pursuant to N.C.G.S. §§ 62-133.8 and 62-133.9. According to legal counsel, those statutes only apply to "a public utility, an electric membership corporation, or a municipality" and while NRLP is subject to rate regulation under N.C.G.S. § 116-35 it is not a "public utility" otherwise subject to Chapter 62. In other words, it is not apparent how NRLP would pay for DSM/EE programs.

The cost question is not trivial. As an example, Duke Energy Progress filed a proposed weatherization assistance energy efficiency program in Docket No. E-2, Sub 1299, on June 6, 2022, that estimated utility costs of $9,685,907:

Income-Qualified Energy Efficiency and Weatherization Assistance Program

Attachment B
Cost-Effectiveness Evaluation

Income Qualified EE & Weatherization Assistance					
		UCT	**TRC**	**RIM**	**Participant**
1	Avoided T&D Electric	$1,414,117	$1,414,117	$1,414,117	$0
2	Cost-Based Avoided Elec Production	$1,870,436	$1,870,436	$1,870,436	$0
3	Cost-Based Avoided Elec Capacity	$1,025,510	$1,025,510	$1,025,510	$0
4	Participant Elec Bill Savings (gross)	$0	$0	$0	$4,608,001
5	Net Lost Revenue Net Fuel	$0	$0	$3,040,849	$0
6	Administration (EM&V) Costs	$461,234	$461,234	$461,234	$0
7	Implementation Costs	$1,205,481	$1,205,481	$1,205,481	$0
8	Incentives	$7,604,945	$0	$7,604,945	$7,604,945
9	Other Utility Costs	$414,248	$414,248	$414,248	$0
10	Participant Costs (gross)	$0	$0	$0	$7,604,945
11	Participant Costs (net)	$0	$7,604,945	$0	$0
12	*Total Benefits*	$4,310,063	$4,310,063	$4,310,063	$12,212,946
13	*Total Costs*	$9,685,907	$9,685,907	$12,726,756	$7,604,945
14	**Benefit/Cost Ratios**	**0.44**	**0.44**	**0.34**	**1.61**
Data represents present value of costs and benefits over the life of the program.					

And another example is the proposal of Duke Energy Carolinas in Docket No. E-7, Sub 1174, to bundle a high efficiency heat pump incentive program with other EE measures. As with the Weatherization program above, the administration and implementation costs alone (lines 6 and 7) are daunting for a utility the size of NRLP:

Attachment B
Cost-Effectiveness Evaluation

Smart $aver® Energy Efficiency

		UCT	TRC	RIM	Participant
1	Avoided T&D Electric	$5,961,714	$5,961,714	$5,961,714	$0
2	Cost-Based Avoided Elec Production	$32,598,585	$32,598,585	$32,598,585	$0
3	Cost-Based Avoided Elec Capacity	$9,738,901	$9,738,901	$9,738,901	$0
4	Participant Elec Bill Savings (gross)	$0	$0	$0	$109,433,097
5	Net Lost Revenue Net Fuel	$0	$0	$56,534,754	$0
6	Administration Costs	$1,274,585	$1,274,585	$1,274,585	$0
7	Implementation Costs	$2,588,723	$2,588,723	$2,588,723	$0
8	Incentives	$19,149,201	$0	$19,149,201	$19,149,201
9	Other Utility Costs	$483,887	$483,887	$483,887	$0
10	Participant Costs	$0	$31,385,221	$0	$39,291,395
11	Total Benefits	$48,299,200	$48,299,200	$48,299,200	$128,582,298
12	Total Costs	$23,496,395	$35,732,415	$80,031,149	$39,291,395
13	**Benefit/Cost Ratios**	**2.06**	**1.35**	**0.60**	**3.27**

Data represents present value of costs and benefits over the life of the program.

Of course, similar programs for NRLP would be at a smaller scale due to having fewer customers, but that does not necessarily mean all the costs to NRLP would be reduced proportionately. I have not sought bids for such programs, but I expect hiring experienced contractors to design, administer, and provide evaluation, measurement, and verification of DMS/EE programs will be expensive regardless of the number of customer participants. And NRLP would have fewer customers over which to spread the upfront costs.

Q. **Does that mean NRLP is opposed to DSM/EE programs?**

A. No, as discussed above NRLP will pursue such programs to the extent funding becomes available and NRLP can obtain support from third parties with experience in addressing building energy efficiency retrofits and in providing low-income assistance.

Q. Which parts of the Public Staff Testimony does NRLP not agree with?

A. As indicated above, NRLP has reached broad agreement with the Public Staff on tariff revisions. NRLP disagrees with some of the adjustments in the testimony of the Public Staff accounting and economic research witnesses. Those issues are addressed in the rebuttal testimony of NRLP witnesses Halley, Jamison and Stark.

Q. Do you have Concerns about the Testimony of Ms. LaPlaca?

A. NRLP values all customers' positions and certainly respects objective and even passionate concerns. However, Ms. LaPlaca has made points that are at worst unfounded or at best misleading to the actual efforts NRLP has taken to address the issues expressed in her testimony.

Q. Please Explain.

A. She summarizes her points as:

> (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 not what its customers want, according to multiple surveys of NRLP customers. While AppState describes itself as "defining sustainability since 1899," [footnote omitted] it has 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.

Regarding her first point, Ms. LaPlaca offers no data to support the assertion that the limited number of rooftop solar customers has been caused by the "buy-all sell-all" rate in the past and will be caused in the future by the proposed standby charge for net billing. What she misses is that the high cost of installing solar PV has also been a factor in dampening demand, particularly in a service territory where there is a high number of renters. A better analysis of what has caused limited adoption of rooftop solar in the NRLP service territory would take into account all factors affecting affordability, including the relative cost of retail electricity for a jurisdiction, the cost of installing rooftop solar PV, the high percentage of rental properties, and whether a lower net metering standby charge is possible without requiring cross subsidy from other ratepayers.

Ms. Laplaca references Asheville, Durham, Greensboro, and Charlotte as having more rooftop solar than Boone due to "more sensible rooftop solar rules." These locations all are served by Duke Energy, which by its own admission has offered solar rates that are cross subsidized by non-participating customers. It is no surprise that some cities have more rooftop solar where such facilities were enjoying subsidization at the expense of other ratepayers. In response to current law, Duke Energy is now revising its net metering rates to require better fixed cost recovery from solar customers and thereby reduce or eliminate the cross-subsidies. *See* the Commission's March 23, 2023, Order Approving Revised Net Metering Tariffs in Docket No. E-100 Sub 180.

Ms. Laplaca criticizes the NRLP "Buy All/Sell All" rate offering in specific and NRLP sustainability efforts in general. As shown on Miller Rebuttal Exhibit No. 2, which was provided to Appalachian Voices in response to their Data Request No. 4.3, NRLP is one of 36 public power utilities offering customer-owned generation solar rates under "Buy/All/Sell/All." Now with the proposed net billing rate, there will be two customer-owned generation options for NRLP customers. It is also noteworthy from Miller Rebuttal Exhibit No. 2 that NRLP is one of only two utilities of the 68 in this report that offers AMI, Prepay, and rates for customer-owned generation. In addition, NRLP is the only utility that offers more than one option for customers who choose to buy renewable energy.

Regarding her second point, Ms. LaPlaca complains about the fossil fuel percentage in the generating mix of NRLP, but does not mention NRLP is a distribution utility, not a vertically integrated utility with its own generation. NRLP purchases power from the generating company that NRLP has estimated will provide the least cost for consumers. At the same time, NRLP offers a Green Power program where customers can voluntarily pay for renewable zero emission hydroelectric energy instead of the standard generation mix. *See* https://nrlp.appstate.edu/green-power-program Ms. LaPlaca is welcome to sign up for the Green Power program if she wants to do her part for sustainability, but NRLP does not believe it is appropriate at this time to replace its energy purchase contract with Carolina Power Partners with purchase of all or mostly renewable energy. The cost to NRLP ratepayers would be much higher, and there could be reliability issues due to intermittency of renewable generation.

Also, Ms. LaPlaca's statement that natural gas (methane) is "far, far worse for the climate than carbon dioxide (CO2)" is not clear on how much methane emission occurs with natural gas generation. While production and transportation of natural gas may result in some incidental methane leaks – an issue that could be addressed by federal regulation - the primary emission from NRLP's electric supplier is not methane, as the methane in natural gas is burned and the principal by-product of that combustion is carbon dioxide.

Regarding her third point, Ms. LaPlaca uses the harsh and unfair terms of "greenwashing" and "lack of transparency," and concludes that NRLP "could be adding to the mental anguish, depression, and anxiety our youth are suffering." NRLP has been transparent about purchasing power from Carolina Power Partners, which relies in large part on natural gas generation. At the same time, NRLP has sought to offer the renewable alternative of the Green Power program for customers willing to pay to go further toward emission reductions and has in the present rate case offered net billing for the first time. While NRLP has not proposed cross-subsidies for solar or otherwise sought to completely change the fuel mix of its power supplier, NRLP has made reasonable efforts toward cleaner energy within the constraints of least-cost ratemaking and the law against cross-subsidies. Moreover, the statement that NRLP has possibly contributed to mental health problems among "our youth," including suicides at North Carolina universities, is unfair and unsupported.

Ms. Laplaca refers to "multiple customer surveys over the past decade." It was from these studies that the Green Power Program was developed and approved by the NCUC. The studies conducted by NRLP indicated that 2/3 of NRLP customers would be willing to purchase renewable energy at a premium cost if offered. As of June 2023, less than 200 of NRLP's residential customers have subscribed to the Green Power Program, which is less than 3% of customers. NRLP continues to find that indication of a desire of a program offered in a survey does not necessarily mean that there will be a subscription if offered, especially if there is an additional cost.

A key fact not mentioned by Ms. LaPlaca is that any material impact that North Carolina renewable energy has in mitigating climate change would necessarily involve utility scale solar. Scale matters, and rooftop solar PV does not have the cost advantages or generation capability that large solar farms do. My understanding is that North Carolina has a relatively large amount of utility scale solar energy. *See* https://www.forbes.com/home-improvement/solar/best-worst-states-solar/ and https://www.eia.gov/beta/states/states/NC/overview Ms. LaPlaca identifies climate change as a problem but then focuses on small scale rooftop solar as if that were the solution, without acknowledging that utility scale renewables is less costly per kW and better suited to have real impact on the generation mix.

Q: Does this conclude your Rebuttal Testimony?

A: Yes, it does.

SUMMARY OF REBUTTAL TESTIMONY OF EDMOND MILLER

ON BEHALF OF NEW RIVER LIGHT & POWER

DOCKET NO. E-34, SUBS 54 & 55
JULY 10, 2023

My rebuttal testimony accepts several recommendations from the Public Staff, including:

- New River would file an annual report on Schedule NBR net billing activity in each PPA proceeding for New River.
- Both Schedules NBR and PPR are amended to state that any RECs associated with electricity delivered to the grid by New River customers will be retained by those customers.
- There should be a five-year review of Schedule NBR, and the energy credit for Schedule NBR will be adjusted with each PPA filing based on the rate schedule under which participating customers receive service from New River.
- The PPR rate will be based on total system costs instead of residential class costs.
- There should be a five-year review of Schedule PPR, the PPR will be adjusted with each PPA filing, and the PPR may also be reviewed during biennial avoided cost proceedings.
- Schedule IR is amended to pay a credit only to participants who curtail at the coincident peak.
- Reconnection fees are reduced to $11.50.
- Rate design is modified to eliminate the proposed two-year phase-in for the Commercial Demand class and to move class rates of return closer to the overall rate of return.

With regard to Appalachian Voices testimony on DSM/EE programs, my rebuttal accepts the idea that New River pursue certain DSM/EE programs; provided that outside funding is available and that third parties can be hired to run the programs. New River simply does not have the financial or staffing resources to develop and operate DSM/EE programs.

Finally, my rebuttal testimony responds to the position of Ms. LaPlaca. In brief, her suggestions for much greater NRLP support of solar energy do not account for the consequences that such changes would create, including cross subsidies by non-solar customers, contrary to North Carolina law, reliability challenges, and large rate increases for all customers if all natural gas-based electricity were to be replaced with renewables.

MR. DROOZ: Mr. Miller is available for cross-examination.

COMMISSIONER KEMERAIT: So we have cross-examination from Appalachian Voices and Ms. LaPlaca. So Appalachian Voices, would you like to begin?

MR. JIMENEZ: Sure thing. Nick Jimenez for Appalachian Voices. Good afternoon.

CROSS EXAMINATION BY MR. JIMENEZ:

Q Mr. Miller, you testified in your direct testimony on page 7 that NRLP is proposing a new net billing, correct?

A Yes.

Q Has NRLP ever offered net metering in the past?

A Can you define "net metering"?

Q How about net billing?

A Net billing, no.

Q Are you familiar with the 1.4 kilowatt photovoltaic system located on Katherine Harper Hall/Kerr Scott Hall at 397 River Street in Boone, North Carolina?

A I'm not familiar with that specific system on the issue. Katherine Harper Hall?

Q That's -- that's --

A And the size?
Q 1.4 kilowatts.
COMMISSIONER KEMERAIT: Could I ask that both speak more directly into the microphone. I'm having a little difficulty.
THE WITNESS: I apologize.
COMMISSIONER KEMERAIT: Thank you.
A I'm aware of a number of solar sites on Appalachian campus. I can't specifically recall that specific site.
Q Are those solar sites compensated through net billing or net metering?
A No, they are not.
Q How about the windmill? Do you recall your responses to Appalachian Voices' discover requests concerning buy all/sell all and the difference in compensation for the windmill?
A The windmill is on Appalachian's campus. It's on the campus rate which addresses the benefits of solar and wind customer generation, in that tariff, so it does not fall under either one of the customer generation rates, one that's being proposed in the existing one. It's under the ASU tariff.

Q And as you explained it, do you recall your explanation in discovery -- I'm trying to avoid introducing exhibits to take more time, and see if we can just go through your recollection. Do you recall that you said that it is compensated for the electricity generated at the per kilowatt energy charge for the ASU campus?

A It is addressed through the two demand components under the Appalachian State tariff, and so there's two demand components and an energy component for that tariff. One is the actual read demand. The other one is compensating, taking the demand for the generation and adding it back, so it compensates for the fixed costs recovery and approved by the Utilities Commission and recommended by the Staff.

MR. DROOZ: Excuse me. Mr. Miller, could you pull that microphone closer to you, especially if you're turning to address --

THE WITNESS: I apologize. I'll do my best.

A The Appalachian State campus is served under one master meter. That master meter is under the approved tariff that serves the campus. It's the ASU billing rate. That billing rate is designed to net out any generation that's behind the campus meter. That tariff also includes a demand rate. That is actual demand that we read at the meter. It also takes into account a charge where we take that demand rate and we add the demand that is recorded on all the generating facilities on campus in an effort to recover all fixed costs.

MR. JIMENEZ: I do have a couple exhibits for this next question. Apologies. There's four exhibits. The first I would like to -- I'd mark for identification as Appalachian Voices Cross-Examination Miller Direct Exhibit 1. This is NRLP's response to Fifth Set of Written Discovery request to New River Light and Power of Appalachian Voices. This is Item 5-1, and I will just pass this out.

(Exhibits passed out)

MR. JIMENEZ: I'd like to proceed and then perhaps ask Mr. Miller about them all at once, if that's all right.

COMMISSIONER KEMERAIT: Yes. Go ahead and pass out all of the exhibits, and then we can have all of them premarked.

MR. JIMENEZ: Okay.

COMMISSIONER KEMERAIT: So if everyone has the exhibits, this is to make sure we're all on the same page as Appalachian Voices Cross-Examination Miller Exhibit No. 1, I have New River Response to Fifth Set of Written Discovery Requests?

MR. JIMENEZ: Correct.

COMMISSIONER KEMERAIT: And then for Appalachian Voices Cross-Examination Miller Exhibit No. 2 is entitled "New River's Response to Appalachian Voices Data Request Number 5." It begins with "Proposed ASU Solar Facility."

MR. JIMENEZ: Correct, Item 5-1.a.

COMMISSIONER KEMERAIT: 5-1.a. Okay. And then Exhibit No. 3 is New River's Response to Appalachian Voices Data Request Number 5, Item 5-1.a.

MR. JIMENEZ: Correct, the Excel.

COMMISSIONER KEMERAIT: And then Exhibit No. 4 is Data Request Number 5, Item 5-1.b.

MR. JIMENEZ: Correct. Thank you, Commissioner.

(WHEREUPON, Appalachian Voices Cross-Examination Miller Direct Exhibits 1-4 are marked for identification.)

COMMISSIONER KEMERAIT: You may proceed.

BY MR. JIMENEZ:

Q Mr. Miller, do you recognize these exhibits?

A I certainly see my name on them, so I must say that they're part of this investigation in this pursuit, yes.

Q Okay. Thank you. And I want to recognize that Exhibit 1 identifies Randall Halley as responsible for that response, but you were included in a lot of the other exhibits, so I wanted to ask you about this anyway. I just wanted to acknowledge that. Okay. So according to Exhibit 1, this is all about a proposed ASU solar facility. Is that right? If you see the end of the beginning -- the end of the discovery request there?

A We certainly were looking at any opportunity we can to provide service to our customers, including Appalachian, so we were looking at investigating a possible solar site, that's correct.

Q Okay. And the email chain in Exhibit 4 is your back and forth with Witness Halley concerning how to compensate the potential ASU solar facility?

A I haven't read it thoroughly but it certainly appears to be that way.
Q Okay. And Exhibit 3, the Excel spreadsheet, that's something that Witness Halley prepared at your request?
A I can't say that he addressed it or that he prepared it or not. I don't know who prepared that spreadsheet.
Q Okay. I'm going to focus on Exhibit 2. Do you see at the bottom where it says, "Thoughts: Ed, did I capture your initial thoughts correctly?" That's you, right?
A That's correct.
Q Did that capture your thoughts correctly?
A To the extent that we are trying to find ways to bring solar and facilities and projects to New River that serves all of our customers, I would think that the intent of this letter is to try to look at opportunities that better our system and provide service to our customers.
Q Let me see if I understand how compensation would work under this plan. So tell me if this is incorrect. NRLP would calculate what its monthly CPP bill would have been without the

solar facility. That's kind of step one. Does that sound right? If it helps, it's in the second paragraph, the third sentence.

A Can you repeat your question, please?

Q I'm calling it the first step, but one part of this analysis anyway is that NRLP would calculate what its monthly CPP bill would have been without ASU solar facility.

A That is correct. I see it also one or two -- the next step is to ensure savings to the customer and make sure that the customers that are not participating are not negatively impacted. That's correct.

Q Okay. So then the difference, those savings would be passed to ASU in cash. Is that right?

MR. DROOZ: Chair Kemerait, I have an objection here. It's not apparent to me what the relevance of this proposed facility is to the rate case since the rate case is dealing with actual costs that have been incurred by New River, and not anticipating to recover potential costs of a future potential proposed solar facility.

COMMISSIONER KEMERAIT: And would you like to respond?

MR. JIMENEZ: Certainly. This illustrates how ASU thinks about compensating -- rather, how NRLP thinks about compensating solar at ASU installs compared to solar that the rest of its customers installs.

COMMISSIONER KEMERAIT: I'm going to overrule the objection. With that being said, let's focus as much as we can on the issues that are very directly related to this particular matter, but please proceed with this question and I'll ask the witness to answer the question.

MR. JIMENEZ: Thank you.

Q Okay. And so the difference, the savings that we just talked about would be passed to ASU in cash, correct?

A I don't know if it would be cash. I don't know if it would be a credit to a bill. This was an initial investigation on seeing how we could possibly place solar on New River's system. It happens to be on ASU. Quite frankly, looking at this document, I don't even know if it's on ASU's campus, okay. It's for ASU. I believe this was a possible exercise, a possible -- and there was -- we did a number of work with the Energy

Center looking at DOE grants, looking at opportunities to bring savings to New River. This particular project, again, we go through the litmus test to see if it benefits the customer and all customers to New River. So there are a number of projects that we continue to work with with the faculty and other folks that come to New River to see if there's a potential project.

Q Okay. I'll skip to what I took away from this as the problem that you identified. NRLP would charge ASU the same amount in an extra facilities charge, right, at the end of that first paragraph as part of the proposal?

A Part of our tariffs, we have an extra facilities charge. If any customer has a -- requests a service that's above and beyond normal services, then we have an extra facilities charge, and we are exploring to see if that could apply.

Q Okay. And extra facilities charges are based on 0.87 percent of the cost to connect a facility, right?

A I don't have the tariff in front of me but it's defined in the tariff of how we calculate our extra facilities charge based on a capital investment.

Q It's in the third paragraph, the second -- third sentence, .87 percent?

A Again, at this time, I don't even know what our existing tariff or what our extra facilities charges is. So it reads 8.75 -- excuse me, .87 percent.

Q And then the monthly savings -- again, in this third paragraph, if you assume the facility is 1 megawatt solar only, the estimated monthly savings were $6,333?

A This is what the document says.

Q And it's dividing that by the 0.87 percent. Extra facilities charge implies a cost to connect of $724,000?

A That's what the document indicates. Again, this was one of many projects that we looked at to explore. Looking at a number of solar sites as our customers have asked us to do, to look for solar, to come to New River, and so this is one exercise where we try to find ways to bring generation to the high country.

Q If you'll look at Exhibit 3, the last line, that amount is just -- is too high, right?

A And I apologize in my numbering here. In Exhibit 3, is that the email correspondence?
Q No, sir. That's sort of an Excel spreadsheet. It looks like this.
A Okay. NRLP, the cost to connect the facility, 723,000, and it indicates this is too high. Okay.
Q And that was the reason the proposal was amended?
A Again, I do not recall the specific proposal. I do not know what regions we came through. We look at a number of opportunities of installing solar and other projects at New River. We continue to work with the University that either we bring ideas to the University and the faculty or they bring it to us, and we investigate and look and see the feasibility, see if it betters the utility or our customers.
Q So considering those examples, isn't it true that ASU has offered net metering or net billing to -- rather, NRLP's has offered it to ASU but not to its other customers?
A There was no offer. This is a study. This is us putting out a piece of paper and seeing if we can make something work. I don't believe that there was any proposal or any creation. Certainly,

nothing was brought in the form of net metering or net billing to gain approval for that, and we would have to go through that next stop if we felt we had a project to see what requirements in order to implement that.

Q Moving to your rebuttal testimony, you discussed the prepaid program in response to Witness Hoyle's testimony concerning Energy Efficiency and Demand-Side Management Programs. This is on page 8 at lines 5 to 24.

A This is my rebuttal?

Q Yes, sir.

A Okay. And what line are you referring to?

Q 5 to 24, actually. You discuss Witness Hoyle's testimony concerning EE/DSM and then move to -- on line 23, *NRLP was working to develop a prepaid service rider?*

A That's correct. We are currently working with Public Staff gaining approval from the Commission. We have a prepaid program at New River Light and Power that we offer to our customers.

Q I'm going to try to skip an exhibit and go from your recollection. Do you recall a response to a data request saying that this program has also shown indication of reducing energy consumption since customers are more aware of usage?

A I do recall that. I recall that based on a number of studies that was shared with us, that prepaid program. When you provide that to the customer, they're more sensitive to their usage and it reduces their consumption.

Q Also going from your recollection, this is the Prepaid Service Rider filed June 22nd, 2022. Do you recall or is it your understanding that a customer, when they're balanced at zero, they're disconnected the next business day?

A We have a policy set with a prepaid program where the customer is notified when they're getting close to having a zero balance. And once they reach that zero balance, then they're terminated or disconnected for non-pay if -- and there's some restrictions regarding weather and where, how close they are to the end of the business day, but we make every effort to communicate with the customer prior to disconnection.

Q And, again, recollection, this is from NRLP's latest report on the Prepaid Service Program.

Does it sound right that there were between 47 and 120 disconnections per month except for February and March in 2022?

A I cannot tell you the number of disconnections we had at New River.

Q Subject to check would be fine too, if that's --

A We'll have to check but I have no idea what the disconnects are at New River.

Q Same for 69 customers who were with more than one disconnection within a 90-day period.

A Subject to check. I can't verify that.

Q Are you aware that there is a Commission Rule against disconnecting service for nonpayment of bills without having first tried to induce the customer to pay, and that NRLP sought and obtained a waiver of that rule to establish the program?

A The purpose of the prepaid program was that we notify the customer electronically before disconnect, but there is no paper. It requires the customer to have an email for us to implement the prepaid program, and Public Staff was very careful that we adhere to communicate with the customer.

Q Can you tell me how long it is between when a resi -- a customer on schedule are -- runs out of money or, you know, hasn't paid their bill and when they're disconnected?

A Are you referring to prepaid or are you referring to a regular customer?

Q On Schedule R, regular residential customer.

A Regular, regular R, customer, I believe, goes nearly two months before we actually disconnect them. I cannot tell you the period of time that they are between delinquency and actual cutoff, no.

Q So the indication of saving -- reducing energy consumption since customers are more aware of their usage, is it fair to say that that's because the customers know their power will be cut off the next business day if they run out of funds?

A I think -- you're referring to prepaid now?

Q On prepaid, sorry, yes.

A Well, going back to prepay? Okay. The purpose of prepay is to continue to communicate with the customer their usage. We can notify them and they're notified where their usage is and where their balance is. So it is not intended to enhance or improve collection at all. It is not targeting any particular class or demographic. It is only -- the intention of the prepaid program is to offer a service so customers can be aware of their consumption.

Q Does NRLP consider the prepaid program a form of Energy Efficiency or Demand-Side Management?

A New River Light and Power, with our AMI system, gained approval from Public Staff or recommendation from Public Staff that we could implement the prepaid program as an effort that satisfies the requirements mentioned in previous testimony regarding Energy Efficiency.

Q Okay. So is that a yes, NRLP considers it an Energy Efficiency program?

A And Public Staff also agrees that that's what we could use to address the pursuit of energy efficiency at that time. Obviously, we were pursuing other energy efficiency efforts at New River regarding grants and funding, but that right there, specifically since our last rate case, we certainly implemented the prepaid program since we had our AMI system and we were eager to offer that to our customers.

Q In response to Witness Hoyle's testimony concerning EE/DSM programs, you also mentioned that NRLP offers its Green Power Program?

A That is correct. We offer our Green Power Program, and that was only the result in the last -- since our -- converting to our new wholesale provider were we allowed to pursue the Green Power Program which serves all customers, offered to all customers.

Q I'm going to try to skip more exhibits and just test your understanding as you sit here today. The power purchased through the Green Power Program comes from a number of hydroelectric dams. Is that right?

A We entered an agreement with a utility, Brookefield, and we purchased 17 million kilowatt-hours of hydro generation to meet the request of our customers under the Green Power Program.

Q To the best of your knowledge, were any of those hydro facilities constructed as a result of the Green Power Program?

A To the best -- no.

Q And to the best of your knowledge, would they shutter without the Green Power Program?

A Can you repeat that again?

Q To the best of your knowledge, would they shutter or stop operating without the Green Power Program?

A I have no idea whether they would -- if it's depending on the Green Power Program or not. I reached a wholesale agreement with Brookfield. They met that requirement and serviced electricity.

Q So you testified that an NRLP survey indicated that two-thirds of customers would be willing to purchase renewable energy at a premium if offered, but fewer than 200 customers or fewer than 3 percent signed up. That's on page 16, lines 10 to 14. Is that right?

A That's a correct statement. As of last month, we have 175 residential customers assigned to the Green Power Program and our surveys indicated that over 4,000 residential customers should be signing up. Our survey was conducted in 2017 and 2020. The 2020 was very specific to the boundaries of the Green Power Program. So the response to the Green Power Program, although we continue to pursue, is somewhat lower by a factor of maybe of what was indicated by our customers when they've completed the survey.

Q And you testified that NRLP continues to find that -- that indication of desire for a program does not necessarily mean that customers will subscribe when it's offered, especially if there's an additional cost. That's again on page 16, lines 15 and 16.

A We found that when we asked in our survey, the 2020 survey, we asked specifically if a customer would pay $5.00 for 250 kilowatt-hours, or approximately one-third of the average residential customers' load. We had an overwhelming response from residential customers at that time that they would subscribe to the Green Power Program. We were also specific in that it was not specific to one source but it was also -- it could be hydro wind. We were not specific to solar or hydro or anything else. And the response to the customers was -- caused us to expend the effort and the expense to pursue the Green Power Program, and at this time, we have

175 residential customers. However, we've offset 17 million kilowatt-hours of purchases from the CPP by the subscription of Appalachian State, Town of Boone, and the County, Watauga County who have subscribed to the Green Power Program that's a huge success, but it's from a residential standpoint we do not have a significant subscription.

Q Besides the additional costs, has NRLP considered other reasons customers might not sign up for Green Power?

A I cannot understand, based on the survey. The customers that said yes to the survey, we are offering it through the Green Power Program, so I am not real clear why our customers are not subscribing.

Q Does NRLP consider the Green Power Program either Energy Efficiency or Demand-Side Management?

A Repeat the question?

Q Does NRLP consider the Green Power Program Energy Efficiency or Demand-Side Management?

A We see it as a customer service or an option to our customers that they requested, again, mentioned through our surveys, and we've pursued that based on their response. As far as Energy Efficiency or Demand-Side Management, we've pursued other areas that probably, typically align more in Energy Efficiency or Demand-Side Management than the Green Power Program. The intent of the Green Power Program, as signing our CPP contract, is to offer choice to our customers of where their energy comes from.

Q Almost done. You testified NRLP has not proposed a slate of EE/DSM programs because it does not have the staffing and resources and because it does not qualify for cost recovery under the EE/DSM statutes. And for that, you cited NRLP's legal counsel's opinion. This is page -- yeah, page 9, lines 5 through 9. Does that sound right?

A That is correct.

Q NRLP has not sought the Commission's determination whether it can recover for EE/DSM programs, either under the EE/DSM statutes or otherwise, has it?

A We have not.

Q NRLP developed Rider RER for the Green Power Program voluntarily, right?

A That is correct.
Q In response to consumer interest?
A That is correct.
MR. JIMENEZ: No further questions. Oh, sorry. I'm going to pass to my counsel, co-counsel.
CROSS EXAMINATION BY MR. MAGARIRA:
Q Good afternoon, Mr. Miller. Munashe Magarira, co-counsel for Appalachian Voices. Just, I think probably a couple questions, very brief.
Mr. Miller, in your direct testimony, this is page 3 beginning on line 10, you note that New River's rates compare favorably to other North Carolina electric utilities. Is that right?
A That is correct.
Q And in your testimony, this is the same page, I think, you state that based on 2021 EIA data, New River was the lowest cost provider for residential consumers in North Carolina?
A That's correct.
Q However, that rating would only apply to the rates that were in effect when EIA conducted that analysis?
A They were reported by EIA in 2021 and we consistent -- New River consistently is one of

the lowest cost utility providers. I can only go on the EIA data. I can't speculate. I do have current numbers as how we compare. Obviously, we remain among the lowest cost providers and certainly we will remain lower. We continue to remain, even after the proposed increase. We'll remain lower, below our surrounding utility. And after the phase-in of both Duke Carolinas and initially on Duke Progress, we remain among the lowest cost or the lowest cost provider of those utilities.

Q So you, kind of, predicted my next line of questioning. Obviously, New River is proposing to increase its rates. Have you had the chance to review Bob Hinton's direct testimony filed June 6?

A Specifically?

Q Specifically with respect to what the -- again, understanding that there's a stipulation that will, sort of, change things, based on the proposed rates, did you see, sort of, his analysis as to what the average bill would be if those rates were approved?

A I do not recall specifically what his bills were.

I've worked with our consultant, Randy Halley, who has generated those typical bills based on 1,000 kilowatt-hours for residential customers.

Q Sure.

MR. MAGARIRA: Commissioner Kemerait, may I approach? I have a -- this is the page where Mr. Hinton, sort of, lays out what the average bill would be.

COMMISSIONER KEMERAIT: Yes, you may approach.

MR. MAGARIRA: I have additional copies, but this is just from the record. I'll give a copy to Mr. Miller and then also to counsel just so they can see it.

BY MR. MAGARIRA:

Q Can I have you read out loud, into the record, lines 10 through 16 that are on that page?

A *In addition, the proposed increase in residential rates would result in a $139 average bill assuming 1,000 kilowatt-hour usage. This is similar to the 133 average energy bill that the same customer would receive from Blue Ridge Electric Membership Corporation or the $138 bill they would receive from Duke Energy Progress.*

NRLP customer bills would be higher than North Carolina customers served by Duke Energy Carolinas and Dominion Energy.

Q Okay. Thank you. And are you aware of any testimony that New River or the Public Staff has filed since the filing of the Stipulation that recalculates what that average bill would be?

A Can you repeat that question?

Q Are you aware of any testimony that New River or the Public Staff has filed since the filing of the Stipulation that would recalculate what the average bill would be?

A I'm not aware of that, no.

MR. MAGARIRA: No further questions.

COMMISSIONER KEMERAIT: Ms. LaPlaca.

MS. LAPLACA: Yes, thank you. And I'm going to ask legal questions so that we could just get to the point here.

CROSS EXAMINATION BY MS. LAPLACA:

Q Mr. Miller, I just want to ask you a couple questions about basics of New River Light and Power. Tell me if you agree or disagree. There are nine -- about 9,000 meters in New River district, about 22 percent of the retail revenues are from ASU, and about 78 percent are residences and businesses. Is this correct?

A Subject to check.

Q Okay. Over the last 15 years of buy all/sell all, we've had 15 solar systems installed, so that's about one per year. So that if New River wanted to have 5 percent of its meters, rooftop -- have rooftop solar, that would be 450 meters out of 9,000 meters. It would take 450 years at the current rate to get to a 5 percent penetration of rooftop solar. Is that correct? Do my numbers sound right?

A I cannot do numbers that fast. I know that New River's buy all/sell all has to -- in working with Public Staff, we are to try to make sure that our rates are non-discriminatory and do not cross-subsidize, as we've heard for the last two days. So the rates that we're offering at New River and what we've proposed continues in that spirit of keeping, ensuring that there's no cross-subsidization. Obviously, with this rate adjustment, we're seeing an increase in both the buy all/sell all and the proposed net billing rate to where the compensation to the generating customers increased.

Q Okay. So considering that only 15 meters out of 9,000 have solar, that is, by my calculation, 0.004 percent of the current customers for New River Light and Power have some kind of rooftop solar. Is that correct?

A Again, I'm not able to do the math. I know that we're consistent with other public utilities in North Carolina that offer similar rates as New River, so I can't speak to the math that you're citing, Ms. LaPlaca.

Q Okay. Moving on to what Boone wants, are you aware, Mr. Miller, that I served on the Boone Town Council for two years?

A I am aware of that, yes.

Q Yes. And when I was on Town Council, I got to know a lot people, I talked to a lot of folks. And are you aware that in this docket, the Town of Boone, that's the Town Council, filed a letter in support of fair net metering. And that they recognize that Boone has very little rooftop solar and that the Boone Town Council would like fair net metering, which means no more than $2.00 per kilowatt per month standby charge? Did you see that letter, sir?

A Could you provide that letter, please?

Q It's in the docket. It's been filed in the docket.

A Can I have a copy of that letter, please?

Q Um -- you know, I'll be happy to send it to you, if you want to wait right now. Actually, sir, I'm trying to save time. It's filed in the docket. I know that you got a notice because we all get notices. I have 10 minutes, sir. I want to ask relevant questions, not waste time on making points that we all know are true.

MR. DROOZ: If you are aware of what she is asking about, please respond. If you're not aware, please respond that way.

THE WITNESS: I am aware that the Town of Boone approved a letter on June 28th to be sent to the Utilities Commission. I'm not aware if that letter was received. That's what I'm asking, can I have a copy of that letter.

BY MS. LAPLACA:

Q I'd be happy to send it to you. It's in the docket, sir. I checked. I checked. It's in the docket. Similarly, other letters were filed, one by the Blue Ridge Women in Agriculture which represents a hundred local food producers and 200 to 300 customers per week who also want rooftop solar. Are you aware of that, sir?

A I'm aware of that letter.

Q Okay. Thank you.

A The Town of Boone letter, is it in the docket along with the previous letter that you --

Q Yes, they both are. I checked.

A Can I ask if that's in there?

A Sir, I --

A The last time I checked, I have not seen the Town of Boone's letter.

COMMISSIONER KEMERAIT: Mr. Miller, I think that the questions that you're being asked is just if you are aware of whether it's in the docket, and I think you can answer the question whether you are aware or not aware.

THE WITNESS: I'm not aware of the Town of Boone in the docket. No, I'm not aware of that.

MR. DROOZ: For the sake of the Court Reporter, please don't talk over another person.

THE WITNESS: I apologize.

BY MS. LAPLACA:

Q Okay. Moving on to another line of questioning. Mr. Miller, has any other customer ever intervened in a docket besides me? Are you aware of any?

A I'm not aware of any intervention towards -- in a rate case with New River Light and Power.

Q By any customer, ever?

A I am not aware of an intervention when we file our rate case of any kind. I'm not aware of any intervention.

Q As a customer and one who has been trying to put solar on my home with my partner for five years, I'd like to go through some numbers, please, and ask you if they're accurate. Under buy all/sell all, my partner and I, who re-financed our home four years ago and put away $30,000, we've been trying for years to put solar on our house. And the reason that we couldn't, under the current rules, is because if we put that solar up on our roof, we could not use any of that electricity. Is that true under the current system? Under buy all/sell all, we could not use any electricity so-called behind the meter.

A Buy all/sell all is two separate meters, so we read what's generated and what is consumed by the customer, and there is no net effect.

Q So please, sir, just answer yes or no. Under buy all/sell all, the customer who puts solar on their roof cannot use any of the electricity that is generated by that system. Is that true?

A That is true.

Q Okay, thank you, sir. Now, under the new system, net metering -- thank Heaven, I appreciate New River finally offering that -- I want to explain what would happen to us as customers and I want you to tell me if I'm right or wrong. We plan to buy 10 kilowatts of solar. And just using round numbers, it would cost us $6.00 per kilowatt per month. So, therefore, we would be paying $60 a month fee which translates to $720 a year. Over a 30-year life of that -- of system, that means that we would pay about $22,000 more for the system than the $30,000 initial cost. Does that sound correct, ballpark?

A The net --

Q Yes or no, please, sir.

A I would like to clarify. I would like to answer the question that's given.

Q Okay.

COMMISSIONER KEMERAIT: Please go ahead and answer the question as best as you're able.

A Best that I'm able. Yes, with the net billing rate, with the full retail rates being offered to the customers, there is a fee to the customers for the -- based on 10 kW at $6.00, it will be $60 a month, that is correct. Obviously, we're seeing full retail rates being credited to the customer as well. Yes.

BY MS. LAPLACA:

Q And Mr. Miller, are you aware that a previous utility that imposed a monthly solar fee of $50 a month, which isn't really as high as New River's, experienced a 95 percent reduction in rooftop solar applications after they instituted that fee? It was in my testimony.

A I have not confirmed what you're saying but I've read your testimony and that that was what you shared in your testimony, yes.

Q And Mr. Miller, is New River Light and Power committed to giving customers what they want?

A We want to make sure that all customers are treated the best and provide the highest level of service we possibly can. That's why we generated the Green Power Program, that's why we offer pre-pay, that's why we respond to the customer surveys, why we continue to provide the level of service we do.

Q And Mr. Miller, as a customer who has watched the Green Power Program really not get off the ground, I can tell you why we didn't do it, because we don't want hydro that comes down on the transmission line. We want local clean energy. Does that sound like it could be a reason for the other customers in Boone, who up to 90 percent have indicated an interest in clean energy and yet very, very few people signed up for the Green Power Program?

A I have not heard any -- I have not heard a major communication from our customers that they are declining the Green Power Program because it is not local or is not solar. I'm not hearing that information at all.

Q Mr. Miller, I remember getting a number of requests from New River during some heatwaves in Boone and it said, hey everybody, reduce energy use.

A That's correct.

Q I remember writing back saying, well, if we had rooftop solar, we could reduce our energy use. Do you recall that?

A We have a Beat the Peak Program where our wholesale price cost, whether it's the current wholesale rate or the previous wholesale rate, we're trying to incentivize our customers to curtail their load so that the savings that we see through our PPCA every year will be passed on to our customers. It was an effort to help customers save money on their utility bill.

Q So Mr. Miller, do you recognize that rooftop solar customers reduce the load on the grid during peak times?

A They -- certainly, rooftop solar reduces. With the generation, it reduces and impacts the amount of energy that's purchased by New River. As Mr. Halley's testimony indicated and what's been discussed in the previous base, how it impacts, the demand is what's gone through the calculations by -- and run by the representative from App Voices and New River is how that's calculated. But certainly, a customer that has generation reduces the amount that comes from our wholesale provider.

Q But Mr. Miller, do you recognize that we've had unprecedented heatwaves this year and that just last week, we broke three global temperature records, three, three days in a row, and so that heatwaves are a problem. Do you recognize that, sir?

A I'm certainly aware that we've had some hot weather, sure.

Q And, Mr. Miller, are you aware that the average income in the Town of Boone is about 20, $25,000 a year?

A I have certainly worked with a number of civic organizations and community organizations that recognize the demographics of Watauga County and that we are -- have quite a bit of generational poverty in Watauga County. But the specific footprint of New River Light and Power is unique in that we have a large number of college students and a large number -- and renters, and folks that do not actually have a long-term residency in New River typically will see two-thirds of their customers leave every five years. It's just a rotation. I can't speak to the demographics, but it's unique to the salary of New River's territory of what their income is. I'm not aware of that.

Q Mr. Miller, would you agree with me that probably three-quarters of the customers of New River do not have air conditioning?

A I am not aware of the statistics without air conditioning at all, no. I can't speak to that.

Q Does New River have any plans for a cooling center if Boone should have a heat event such as they had in Portland, Oregon where it hit 116 degrees last year?

A Being part of Appalachian State University, we have an emergency center with our convocation center where there's any kind of an emergency, we can certainly stage that. That's one of the reasons why our convocation was built. It is a center for people to retreat to. That facility has backup and is also served by New River.

Q And one last question, Mr. Miller, on fuel. New River Light and Power had to purchase $7 million worth of additional fuel in order to cover costs due to -- as many people have said, significant cost -- increases in fuel costs in 2022. Are you aware of that?

A Absolutely.

Q $7 million.

A I'm aware of the significant increases. We shared in previous testimony that we have an increase, and all utilities have seen an increase in generation costs or purchase power costs. Certainly.

Q So, Mr. Miller, then, if I look at your revenue requirement, which I believe is about $42 million a year, that $7 million is a significant percentage of that total revenue requirement, is it not?

A $7 million is a significant portion of our budget, yes.

MS. LAPLACA: Okay. I have no further questions. Thank you.

COMMISSIONER KEMERAIT: So it's now time for our afternoon break. It's 3:22, so let's come back at -- in a little more than 10 minutes, 3:35. We'll go off the record.

(Whereupon, a break was taken.)

COMMISSIONER KEMERAIT: So let's go back on the record. It's now 3:36. Our goal and intent is still to finish by five o'clock. I'm thinking that we can do that, so we'll continue to try to be as succinct as possible with all of our questions. And with that, I believe that it is redirect by New River.

REDIRECT EXAMINATION BY MR. DROOZ:

Q Mr. Miller, you were asked about the average bill and whether that of New River might go higher than other utilities. Do you have a comparison that maybe is different than the number that Mr. Hinton had in his direct testimony that you were cross-examined about?

A Yes, I do. Thank you.

Q Can you tell us the source of your information?

A Sure. From the Duke Energy Progress schedule order that was filed with the Public Staff, the effective rates which is the phase-in rates through three years, the proposed monthly rate for 1,000 kilowatt-hours for a residential customer, year 3, would be $150.41. Likewise, Duke Energy Carolinas for the same 1,000 kilowatt-hours would be $134.63. While after all of the discussions with Public Staff and the

Settlement and working with the accountants, New River's calculated costs for 1,000 kilowatt-hours would be $131.95, and that's under the current PPCA.

Q Would that last number you said be for the rates as proposed in the Application after year 1?

A That is a correct statement.

Q And the Settlement rates would be lower than that?

A That is correct.

Q Thank you. Have you seen a letter on energy that was approved by the Boone Town Council this summer?

A On June 28th, the Town Council presented a letter and it was approved, gotten confirmation. That letter, in brief, does not mention any request of $2.00 for a standby charge.

Q And last question here. I believe Ms. LaPlaca asserted that the average income in Boone was $25,000 or so. If New River were to completely eliminate the standby charge, is it likely that many people who have an income of $25,000 are going to be purchasing rooftop solar?

A I understand the cost of the rooftop solar for 10 kW was $30,000, so I really have a hard time understanding why customers would spend a year of their income towards rooftop solar.

MR. DROOZ: That's all. Thank you.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q Okay. So, Mr. Miller, just a couple of very brief questions about New River's plans for the DSM/EE programs and also the Winterization program. And you testified in your rebuttal testimony that New River would be proposing DSM/EE programs and Winterization programs when grant funding became available. Can you briefly describe the status of either applying for the grant funding or progress in receiving it so we will know where New River is in that process?

A Absolutely. New River continues to seek funding. We historically have worked with Appalachian State. We've been successful in receiving a number of grants through the American Public Power Association. We worked collaboratively with Appalachian's analytics department, developed and studied customer behavior. That is in the past. We have gained but we continue to receive grant funding, work with the Energy

Center with DOE grants. We're constantly looking for ways of funding. Specifically to the IRA grant, we have hired a consultant to assist us identify and, quite frankly, go through the difficulty of the alphabet soup of trying to pursue these grants and funding, but we have, are paying for someone to assist us with that. We use Strategics which is a great supporter of many public power or public utilities. Also, we have hired a grant writer that we have employed and we've actually been successful working with the Town of Boone filing for a joint grant for electric vehicle funding. So we are making efforts to better our community and work to seek funding, bring that in.

Now, specifically moving forward, we are a member of a joint action agency, ElectriCities of North Carolina which represents over 70 public power utilities in the State of North Carolina. They, too, are looking for larger grants, grants that we could work collectively and collaboratively. So, working closely with ElectriCities in North Carolina and how we can bring those fundings in.

As always, to implement any kind of Energy Efficiency, weatherization Demand-Side Management, it takes an effort and takes funding just to administer that. Worked -- met with the Energy Center to see -- at Appalachian to see if they could facilitate that. The current effort that we have, similar to our Roundup Program where we receive funds for -- from customers to help others that are in need with their bill pay, New River identifies and recognizes that to administer that program, we don't have the social and the counseling skills to do that. So we've outsourced that and actually worked with another nonprofit to distribute those costs.

We believe that one of the options we have is to also find a third-party to help us administer these grants once they come in so that they're sent to the right folks and the right method. We're looking for that funding to do that. Again, I do not want to bring additional costs to New River just when it's a loss for us. So given the demographics, the majority of our customers are renters, they don't own their homes, and they do not stay with New River, it's very difficult -- we're a unique utility in that regard, as mentioned by Mr. McLawhorn. So that's a concern. We have no industrial customers. So we are a unique utility and we are looking for how we can best serve those customers in that unique demographic that we have in the high country.

Q Thank you for that information. I just have one more question. This relates to the new proposed PPR tariff. In the previous SPP buy all/sell all rates, I think the testimony was there was only about 15 customers who had subscribed to those tariffs. Are you anticipating to see more customers with the PPR tariffs or do you have any idea whether you'll get better subscription to this new buy all/sell all tariff?

A I would like to think that we would get better subscription to the buy all/sell all. I will share with you one of the concerns that I think we all have is that we send the right pricing to our customers. One of the concerns we have at New River, we're not looking to make anything off of our solar programs. We want to make sure that if we offer the right price signal, a customer chooses to invest several thousands of dollars on the solar system; that five years from now, we find out that we overestimated the benefit of that solar. And now, because we want to avoid cross subsidy, we're having to lower those rates.

Moving forward, that causes a very difficult discussion with our customers that made those kind of investments. So I would like to think that our demand-side -- our new net billing rate will offer the correct price signal and we are eager to make sure that we continue to fine-tune that to make sure the signal continues.

Now as far as the buy all/sell all, New River has that existing rate. It was an incremental cost to bring that in. There are -- from the utility standpoint, we're indifferent. We are trying to make this an offer to our customers. Buy all/sell all, many customers, we want to give the option to them. There may be a customer that does not want to put or cannot put solar on their roof. We give them the option to install a separate system. It's buy all/sell all. They can actually have a separate meter and gain benefit from still choosing to install their own solar.

As far as New River's concerned, the substation meter slows down when solar is installed. Whether it's net billing or buy all/sell all, we're buying less from our wholesale providers, so we're indifferent to that. That's one of the benefits we have of entering our new wholesale agreement, is that we have that kind of flexibility with generation.

COMMISSIONER KEMERAIT: Thank you. Questions from Commission? Chair Mitchell?

CHAIR MITCHELL: Just one question and I'll follow up on your last point.

EXAMINATION BY CHAIR MITCHELL:

Q So your existing wholesale arrangement does allow you to meet your needs with additional generation?

A Absolutely.

Q Okay.

A We have a full service purchase contract with Carolina Power Partners. Part of that contract allows us to pursue other sources of energy, but that's a full service contract if -- and I'll let you ask the question.

Q Yeah. I mean, my question really was, do you have the flexibility under the contract to enter into additional arrangements for power supply?
A Absolutely.
Q Okay. And do you -- you've heard my questions to the Public Staff regarding the fuel price volatility and your customers' exposure to that. Does Carolina Power Partners do anything to mitigate fuel price volatility or is there any provision in the contract that provides some measure of protection for your customers?
A There is a provision in the contract. It's somewhat of a multi-party contract. We actually are purchasing our gas free of taxes. It's to another vender, and that gas purchase, we are looking at a long-term hedging strategy, and that adds a little bit of complexity to the effort but we are making steps to hedge, if you will, for future cost of gas.
Q So -- I'm sorry to interrupt you. So New River purchases its gas separately from the power supply contract?
A It's -- technically, it's purchased separately from -- yeah, because energy is a pass-through to

us, yes.

Q Okay. And did you hear -- were you in the room when I asked my questions regarding backstand service?

A I believe you're referring to the December, Christmas Eve event.

Q Well, yes. I asked Mr. McLawhorn about Kings Mountain performance during Winter Storm Elliott, and he said the information he had was confidential, so I did not pursue it with him. But my question is, does New River have to independently seek backstanding service or does the contract with Kings Mountain indicate that Kings Mountain will provide backstanding service?

A It's a full service contract. They have that responsibility of providing the commodity to New River, regardless of the demand, regardless of the amount of energy requested. They have to provide that. And it's their penalty, their cost if they're not able to provide it.

Q Okay. So during Winter Storm Elliott, was there an interruption in service to New River?

A There was an interruption to service to New River but it wasn't generated by Carolina Power

Partners. It was generated by Blue Ridge energy who had the request for curtailment by Duke Energy. We saw that as an emergency and we responded per the request of our transmission provider that we were about to lose the grid, and so we took action. But it was not due to generation, it was due to our contract with Blue Ridge and Duke. They made that request. It was not Carolina Power Partners.

CHAIR MITCHELL: Nothing further. Thank you.

COMMISSIONER KEMERAIT: Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. Miller, I'll be quick. You're the first witness from the Company. I've heard a number thrown around but I have to have you confirm it so that it's official in the record. Is it accurate that you have -- aside from ASU, let's leave them aside -- only 15 customers who are interconnected to your grid and are operating solar photovoltaic generating facilities in parallel with your system? Is that accurate a number, 15?

A We have 15 under the buy all/sell all rate.
Q Thank you.
A We have three customers we believe that have left that are still solar, yes.
Q Everybody else has said it but I need to hear it officially from the Company that that's the right number.
A Yes. That's the last number I had, sir.
Q Are any of those commercial customers or are they all residential customers?
A To my knowledge, we may have one commercial customer but I believe I'm reporting all residential to you, sir.
Q Okay. Are any of those customers the owners of residential units with multiple, multi-family units, in effect?
A No multi-family units.
Q All single-family?
A That is correct.
Q All 15?
A Yes, sir.
Q Great. Second question. I'll be quick about it. In your rebuttal testimony, you've offered up and sponsored revised Miller Rebuttal Exhibit

Number 1. What is the revision that that exhibit made to prior versions of the same exhibit? If you want to reference it, it's Exhibit 1. You talk about it on page 6 of your rebuttal testimony. I just need to tell you -- you to tell me what was the revision that was made? I asked Mr. Barnes about this and he wasn't entirely sure, so you're the sponsor of the exhibit.

A And I apologize, sir. I'm thumbing papers as fast as I --

Q Let me read it to you to save time. You say on page 6 of your rebuttal testimony:

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. How was Exhibit 1 revised? What did you do?

A I think it was just an update of the original data. And what we did was we revisited the solar load. What we had with our AMI system is that the hourly data was collected and there were hours that were missed.

Q Right.

A That missed data, hour one read 6, hour 10 read 30. We averaged those. And that was the only update that we had on that, sir. We averaged out those hours.

Q So the revision made in Exhibit 1 was to average the available data and apply that average to the missing data. Is that accurate? Is that what you just told me?

A All right. I'm going to have to ask when Mr. Halley comes up to make sure that he verifies that, but --

Q That's fine.

A -- but that's to the best of my knowledge, sir.

Q I'm not asking about how that calculation entered into his calculations. I just want to know what the revision to the actual data was.

A I can't answer that, sir.

Q Okay. Thank you. Then the last question for you is what steps is the Applicant taking, going forward from this point, to ensure that its future data collection is complete and accurate in terms of hourly solar production data?

A February of --
Q What steps are you taking?
A Yes, sir. February of 2022, we upgraded our AMI system, and the collection is much more efficient, much more accurate to where we do not have those major gaps. We also, upon the adoption of this, we are obviously going to be monitoring the solar hourly reads to make sure if we see a trend where we're missing data, it would be collected and corrected promptly.
It is not something that we are proud of, that we have these gaps. And it has been corrected since the revision of our AMI system to where we are now collecting -- the meter is now storing that hourly data and dumped and recorded correctly, or more accurately, so not only have we done something since this data was collected, we have also taken proactive steps to make sure we remain active.
Q So your data set is complete from what date forward?
A We began. We had the upgrade on February 2022, sir.
Q Okay. Thank you.

A Yes, sir.

COMMISSIONER CLODFELTER: That's all I have. Commissioner McKissick.

EXAMINATION BY MR. MCKISSICK:

Q Thank you. Just one or two questions. And I certainly appreciate your testimony about what you plan to do moving forward when it comes to DSM and EE. And the thing I'm trying to understand, I guess the Stipulation on the last rate case, kind of, indicated you're going to go out there and evaluate these things.

What have you found based upon what you've evaluated in the past? I mean, what options did you actually explore? What did you actually do? Given the fact that you only have like somewhere between 8,800 and 9,000 customers -- I might have understated that a little bit earlier when Mr. Hinton was on the stand, but, I mean, what actually occurred that you can share with us that will provide some insights in terms of a thorough evaluation, analysis, findings that were made, because I don't see any record of that.

A And I apologize for not having the record, Commissioner.

Q Sure.

A What we have done is -- and I mentioned a number of these grants, as a very small utility of 8,500 customers and 31 employees, we have taken proactive steps and worked closely with a number of efforts to fine-tune and focus on the efficiency of our utility. We cooperated and joined NC State with a -- using our AMI data and properly sizing our transformers. It addresses two things. It addresses losses and it also addresses, quite frankly, the supply chain issues that we have with material and the high cost that we're seeing with our material. We avoided a significant amount of dollars with just our distribution transformers. That's one example.

The second example is just system losses as a whole. We're using our AMI data with cooperation with a number of Ph -- students and professors at NC State with that APPA grant. That's just one example that I took from that. We've spent a large amount of our effort working with our CPP contract and trying to promote our Green Power Program and making New River aware in the community of how we are collaborative and part of our community. Again, our statistics, we're very proud of the statistics of reliability and response to our customers. With 8,500 customers, we continue to see positive numbers from our residential and commercial customers' level of service.

What we're doing as far as DSM or Energy Efficiency, we're really targeting on trying to gain funding and trying to find these programs that actually provide benefit and not an extra cost to our customers. We see -- I see my peers in public power working with the folks at ElectriCities, at the Rebate programs, and Weatherization Programs are something that we struggle to see if they benefit the general public. New River, though, continues to offer free energy audits to our residential customers. Customers that request, we'll come in and actually do a survey of their home and provide an audit for them to give them opportunities to improve their efficiency of their home, and that's free of charge. We bear that cost. We see that beneficial.

Q Well, I certainly hope, moving forward, the consultant that you plan to hire that will help you do an analysis, evaluations to be able to provide some very thoughtful insights and come up with something that's constructive, because I think, you know, we would want to see DSM and EE vigorously pursue to the extent it's feasible, viable to do so. And I'm just curious. I mean, when this utility was started, I mean, it was to provide service to the University, and then it expanded over time.

A That's correct. 1915, we began with three light bulbs outside of the college, yes.

Q And I guess there weren't other service providers that were -- you know, could provide service at the time to contiguous areas.

A It was before the RAI or before the new deal and before the rural electrification, so we were an island for many years providing electric service.

Q But you're no longer an island. I mean, has there ever been given some thought to the idea of being acquired by one of -- some other larger utility that might have greater capacity? Has that never been really evaluated or conceived of as an option if you were looking out 5 to 17 years?

A Sure. Well, sir, I believe we have clear capacity to continue to provide service. Again, our rates are among the lowest in the State --

Q Sure.

A -- continue to be that way. We have a defined territory. It was the Territorial Assignment Act. It restricts us to a certain area. And inside that area, we excel, and so as we are able to continue to provide the high level of service to our customers at a very low cost, I believe that we're in the right place for New River to continue that service.

Q So I take that to mean that the possibility of being acquired by another utility has never really fully been evaluated or there would be little interest in doing so?

A From my position, there's little interest in pursuing that, yes, sir.

Q I can see how that might be. Okay. Thank you.

COMMISSIONER McKISSICK: I have no further questions.

COMMISSIONER KEMERAIT: Commissioner

Duffley.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q You mentioned the Territorial Assignment Act. Was that 1965, do you remember?

A It was a 1965 Territorial Assignment Act, but actually, we have a separate agreement with Blue Ridge energy that defines our territory.

Q Okay. And is that filed with the Commission?

A I believe it is.

Q Okay. And could you provide that as a late-filed exhibit, please?

A Certainly.

Q Okay.

COMMISSIONER DUFFLEY: Thank you.

COMMISSIONER KEMERAIT: Okay. Questions on Commission questions, beginning with Appalachian Voices.

MR. MAGARIRA: None from App Voices. And I've been authorized to represent, on behalf of Ms. LaPlaca, that she waives any questions on Commissioner questions.

COMMISSIONER KEMERAIT: Okay. Thank you. From the Public Staff?

MR. FELLING: No questions from Public

Staff.

COMMISSIONER KEMERAIT: Okay. From New River?

EXAMINATION BY MR. DROOZ:

Q You discussed a moment ago bill comparisons and the relatively lower rates in New River Light and Power. If, in response to Mr. McKissick's question, hypothetically, Appalachian State were to look into selling this, what's the likely outcome of that for residential bills?

A Significant increase in cost to every customer class, residential bills will go up. We continue -- even with the proposed rate adjustments, we are substantially lower than the surrounding utilities, so you would see an increase in cost to every customer in New River.

MR. DROOZ: That's all. Thank you.

COMMISSIONER KEMERAIT: So now I will hear motions from New River and from Appalachian Voices.

MR. DROOZ: We would move that Mr. Miller's two direct exhibits and two rebuttal exhibits be admitted into evidence.

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

(WHEREUPON, Exhibits EM-1, EM-2, and Miller Rebuttal Exhibits 1 and 2 are received into evidence.)

MR. JIMENEZ: App Voices would move that App Voices Cross Examination Exhibit Miller Direct, Exhibits 1 through 4 be moved into the record.

COMMISSIONER KEMERAIT: And with no objection, your motion is allowed.

(WHEREUPON, Appalachian Voices Cross Examination Miller Direct Exhibits 1-4 are received into evidence.)

MR. JIMENEZ: Sorry, Commissioner. I believe I neglected to move Cross Exhibit 1 for Mr. McLawhorn into the record.

COMMISSIONER KEMERAIT: Would you like to go ahead and make that motion now, then?

MR. JIMENEZ: Yes.

COMMISSIONER KEMERAIT: Seeing no objection, that motion is allowed as well.

(WHEREUPON, Appalachian Voices Cross Examination McLawhorn Direct Exhibit 1 is received into evidence.)

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

MR. DROOZ: New River Light and Power next calls Mr. Halley.

COMMISSIONER KEMERAIT: Good afternoon, Mr. Halley.

RANDALL E. HALLEY;
having been duly sworn,
testified as follows:

DIRECT EXAMINATION BY MR. DROOZ:

Q Would you please state your name, business position, and employer and address for the record, please.

A Yeah. My name is Randall Halley. I am a Managing Principal at Summit Utility Advisors. Business address is 7614 Lake Drive, Orlando, Florida. And that was it, right? Okay.

Q That's good. And did you cause to be filed in this proceeding 50 pages of direct testimony with Exhibits, I believe, REH-1 through 24?

A Yes.

Q And of those exhibits, are the Exhibits REH-12 and REH-20 confidential?

A Yes.
Q Okay. And did you also cause to be filed Amended Exhibits REH-3-Version 2, REH-13-Version 2 on April 10th, 2023.
A Yes.
Q And did you cause to be filed 26 pages of rebuttal testimony with Halley Rebuttal Exhibits 1, 2, and 3 and also REH-3, REH-8, REH-13, REH-14, REH-16, REH-19A(G), REH-19A(GL), REH-19A(R), and REH-19B on June 23rd, 2023?
A Yes.
Q And have you caused to be filed three pages of -- excuse me -- yeah, two pages of summary of your direct testimony on July 7th?
A Yes.
Q And three pages of summary of your rebuttal and settlement testimony on July 7th?
A Yes.
Q And did you also cause to be filed finally six pages of settlement testimony with Halley Exhibit -- Settlement Exhibit 1, REH-14, REH-16, REH-19A(R), REH-19A(G), REH-19A(GL), REH-19B on July 6, 2023?
A Yes.

Q And do you have any corrections to any of that testimony?

A I do, on the rebuttal. On page 5 of my rebuttal testimony, on line 8, starting at the second -- there is a sentence that says, "the rate design above" actually should be referencing Halley Rebuttal Exhibit 1, and then on line 15 where it says, "the second," the numbers in the above table should reference Halley Rebuttal Exhibit 1. There was typos in those two lines.

Q And with that correction, is your testimony, as filed otherwise, the same as you would present today?

A Yes.

MR. DROOZ: We would ask that those testimonies be incorporated into the record as if orally read from the stand and that his exhibits be marked for identification as prefiled.

COMMISSIONER KEMERAIT: Mr. Halley's direct testimony filed on December 22nd of 2022 consisting of 50 pages, his rebuttal testimony filed on June 23rd of 2023 consisting of 26 pages, settlement testimony filed on July 6th of 2023, consisting of six pages, the two summaries that were filed, will be copied into the record as if given orally from the stand.

The exhibits and the amended exhibits, 24 exhibits and amended exhibits filed with direct testimony, the exhibits filed with the rebuttal testimony, and the updated exhibits filed with the settlement testimony, will be marked for identification purposes as prefiled.

(WHEREUPON, Exhibits REH-1 through REH-24; Exhibits REH-3-Version 2, REH-13-Version 2; Halley Rebuttal Exhibits 1-3, Exhibits REH-3, REH-8, REH-13,REH-14, REH-16-NRLP Rebuttal, Exhibit REH-19A(G), REH-19A(GL), REH-19A(R), and REH-19B; Halley Settlement Exhibit 1, Exhibits REH-14-Settlement, REH-16, REH-19A(R), REH-19A(G), REH-19A(GL), and REH-19B-Settlement are marked for identification as prefiled.)

(WHEREUPON, the prefiled direct, rebuttal, and settlement testimony, and summaries of Randall E. Halley is copied into the record as if given orally from the stand.)

APPALACHIAN STATE UNIVERSITY
DBA NEW RIVER LIGHT AND POWER
DOCKET NO. E-34, SUB 54

DIRECT TESTIMONY OF RANDALL E. HALLEY

ON BEHALF OF
APPALACHIAN STATE UNIVERSITY
DBA NEW RIVER LIGHT AND POWER

DECEMBER 22, 2022

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Randall E. Halley. I am a Managing Principal with Summit Utility Advisors, Inc. ("Summit"). My business address is 536 W. King St., Orlando, Florida 32804.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of Appalachian State University ("ASU") d/b/a New River Light and Power ("NRLP") regarding its application for a change in rates and fees.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND RELEVANT EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science in Finance from the University of Central Florida. I have 31 years of experience in utility consulting and managing the financial planning efforts of a municipal utility company in Florida. My primary areas of expertise are in revenue requirement, cost of service, rate design, feasibility analyses and power supply evaluations. I have presented testimony to the North Carolina Utilities Commission ("NCUC") and the Florida Public Service Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present (i) NRLP's revenue requirements for the 2021 Test Year with explanations of the pro forma adjustments, (ii) a reasonable rate of return for NRLP to earn on its investment to provide electric service to its customers, (iii) an allocated cost of service analysis showing the revenue requirements to provide service to each customer class, and (iv) the proposed rates to recover NRLP's revenue requirements.

Q. PLEASE DESCRIBE NRLP'S ELECTRIC DISTRIBUTION OPERATION.

A. NRLP operates an electric distribution system whose purpose is to provide safe, affordable, and reliable power supply to ASU, the Town of Boone, and residents and small businesses located in and around Boone, NC. NRLP does not generate electricity, but instead purchases power at wholesale from other companies. The purchased power is delivered over the transmission lines of Duke Energy Carolinas and the distribution lines of Blue Ridge Electric Membership Corporation ("BREMCO") to the distribution system of NRLP.

Q. PLEASE SUMMARIZE YOUR PRIMARY RECOMMENDATIONS IN THIS CASE.

A. My recommendations in this case are as follows:

- The proper rate of return to set in this proceeding is 7.007%, which is based on a capital structure consisting of 52% common equity with a 9.60% return on equity and 48% long-term debt at a cost rate of 4.20%.

- To cover its reasonable costs, NRLP needs a revenue increase from its Base Rates of $4,624,749, which equates to an increase of 24.87% over present Base Rates revenue. This Base Rate revenue increase is partially offset by a decrease in the Purchased Power Adjustment Clause ("PPAC") revenues in the amount of $2,026,355. This equates to an overall system average rate increase of 13.97%.

In addition, I am recommending the removal of one rate structure and the addition of another, as follows :

- After reviewing the detail customer load profile characteristics provided from NRLP's AMI data, it was determined that there is not enough difference in load shapes to have a separate commercial class of customers with load factors at or above the NRLP system average load factor of 65%. Therefore, the Commercial Demand High Load Factor rate schedule should be removed.
- To provide NRLP's customers that have, or will choose to install, on-site solar generation the opportunity to use their renewable energy for their premises and to receive an avoided cost rate for the energy they supply to the grid, in conformity with the non-discrimination/non-cross subsidy provisions in N.C.G.S. § 62-126.4, NRLP is offering a new Net Billing rate schedule. NRLP will also continue to offer the existing buy all / sell all option to purchase renewable energy at its avoided cost rate from its customers.

Q: PLEASE DESCRIBE THE COSTS THAT ASU INCURS TO PROVIDE SERVICE TO NRLP'S CUSTOMERS.

A: NRLP is a receipts supported operating unit of ASU. NRLP maintains a staff of 31 employees who provide engineering, line maintenance, system design and construction, customer service and billing, and certain administrative functions. While NRLP has a limited administrative staff, ASU provides a number of administrative services to NRLP through its own administrative departments, including legal, human resources, information technology, and other administrative services such as finance and facilities management. In addition to the costs incurred to operate and maintain the system, ASU's costs also include a fair and reasonable return on its investment in NRLP, which is necessary for financing capital costs. The total costs of owning, operating, and maintaining the electric system make up the total revenue requirement of the system.

Q: WHAT IS THE TEST YEAR IN THIS PROCEEDING?

A: The Test Year in this proceeding is calendar year 2021. In addition, I present known and measurable changes to the Test Year revenue requirement -- as of the date of filing this testimony -- that represent real costs to NRLP and should be allowed for recovery through rates. NRLP may further update its revenue requirement calculations as allowed by statute.

Q: PLEASE PROVIDE A BREAKDOWN OF THE TEST YEAR REVENUE REQUIREMENT BEFORE ANY ADJUSTMENTS.

A: Exhibit REH-1 is a breakdown of the Test Year revenue requirement before any adjustments for known and measurable changes. Expenses included in the revenue requirement are total purchased power expenses of $10.1 million, distribution operating and maintenance expenses of $1.4 million, $0.779 million for customer accounts expense, $1.283 million for administrative and general expenses, $0.974 million for depreciation expense, and other expenses totaling $0.250 million. The revenue requirement was offset by $257,297 in Other Operating Revenues.

For comparison, see Exhibit REH-13 for the revenue requirement after pro forma adjustments.

Rate Base consists of the original cost of Electric Plant in Service less Accumulated Depreciation, plus Plant Materials and Supplies, required Investments in BREMCO, North Carolina Electric Membership Corporation ("NCEMC") and Meridian Cooperative, prepayments and Cash Working Capital, less Customer Deposits. Rate base items were reflected on NRLP's balance sheet as of December 31, 2021, with the additional capital projects closed to plant-in-service during 2022, cash working capital, and pro forma adjustments for the recovery of regulatory assets discussed later in my testimony.

Q: WHAT METHOD DID YOU USE TO DETERMINE CASH WORKING CAPITAL?

A: Cash Working Capital was determined based on the "1/8 O&M" methodology, with adjustments to recognize a shorter lag on purchased power expenses. Many regulatory commissions have historically allowed the use of the 1/8 O&M methodology when a full lead-lag study has not been developed. The Commission approved a 1/8 O&M methodology for working capital for non-purchased power expenses in the last NRLP rate case, Docket No. E-34, Sub 46. This methodology assumes that a utility incurs its costs of providing service mid-month and receives its revenues for that service 45 days later. The 1/8 calculation is 45/365 days as applied to a utility's operating and maintenance expenses, and it provides the carrying cost of the 45-day lag.

NRLP pays for its purchased power in the middle of the month following service. That means Cash Working Capital for purchased power is needed to cover a 15-day lag between payment of that cost and receipt of revenues to cover the cost.

Fifteen days of purchased power and 45 days of all other operating and maintenance expenses was used to determine Cash Working Capital for the unadjusted revenue requirement. Based on total expenses before pro forma adjustments, the Cash Working Capital is $846,620.

Q: WHAT IS THE RETURN COMPONENT OF REVENUE REQUIREMENT?

A: The return component of the revenue requirement shown on Exhibit REH-1 is $1.803 million, which is calculated using an 7.007% weighted average cost of capital as supported hereinafter.

Q: HOW WERE THE REVENUES CALCULATED ON EXHIBIT REH-1?

A: The revenues on Exhibit REH-1 were based on actual revenues received in the Test Year as reported in the 2021 financial statements. These reported amounts include revenues generated from Base Rates, PPAC and Coal Ash Cost Recovery ("CACR").

Q: WHAT WAS THE TOTAL REVENUE REQUIREMENT FOR THE TEST YEAR BEFORE ADJUSTMENTS?

A: As shown on Exhibit REH-1, the total revenue requirement for the Test Year before pro forma adjustments was $16.399 million.

Q: WAS THERE A REVENUE DEFICIENCY IN THE TEST YEAR?

A: Yes, as shown in Exhibit REH-1, there was a revenue deficiency of $112,252, which is 0.69% of total revenues in the Test Year. This is the starting point for my analysis; the revenue deficiency after adjustments is the appropriate basis for determining the necessary rate increase.

Q: YOU INDICATED THAT YOU MADE SEVERAL PRO FORMA ADJUSTMENTS TO THE TEST YEAR REVENUE REQUIREMENTS. WHY WAS IT NECESSARY TO MAKE THESE ADJUSTMENTS?

A: While NRLP is using a 2021 Test Year, known and measurable changes have occurred since the end of the test year and need to be adjusted in order set reasonable rates for this proceeding. By recognizing the known and measurable changes in setting the rates in this proceeding, it is ASU's hope that it will avoid a degree of regulatory lag and the expense of another rate case "pancaked" so closely with this current case. Pro forma adjustments are appropriate under N.C.G.S. § 62-133.

Q: WHAT ADJUSTMENTS ARE YOU PROPOSING TO THE REVENUE REQUIREMENT?

A: The pro forma adjustments I am proposing are as follows:

- Increasing depreciation as the result of the effect of adding a new campus substation;

- Increasing depreciation expense for the completion of other capital projects – Laydown Yard, SCADA, Underground Conversions, and Warehouse;
- Removing the previously approved amortization expense of the old meters no longer used and useful . The amortization of this item will be completed at the end of 2022;
- Establishing an amortization based on the undepreciated balance of the old campus substation that has been retired from service;
- Establishing a regulatory asset and amortization of costs associated with the new campus substation beginning with the in-service date and the effective date of the new rates approved in this proceeding;
- Establishing a regulatory asset and the amortization of extraordinary unrecovered tax expense associated with NRLP's Unrelated Business Income Tax ("UBIT");
- Establishing an amortization of contracted legal and consulting services incurred by NRLP for this Rate Case;
- Adjusting salary increases that occurred after December 31, 2021;
- Adjusting other operating expenses for inflation;
- Adjusting Electric Plant in Service and Accumulated Depreciation to include the new campus substation and the other capital projects completed after December 31, 2021;
- Adjusting Cash Working Capital;

- Adjusting the revenue requirement for the additional uncollectible accounts and regulatory fees that are based on a percentage of revenue; and
- Adjusting the revenue requirement to account for NRLP's on-going level of UBIT expense.

I will address each of these items separately herein.

Q: DID YOU MAKE A PRO FORMA ADJUSTMENT TO REVENUES?

A: Yes. Revenues for each customer class were adjusted to include only those revenues generated by NRLP's current Base Rates. Revenues for PPAC and CACR were excluded for this purpose. The Test Year 2021 revenues were developed by applying NRLP's current Base Rates to the actual customer billing determinants for the Test Year.

However, no adjustments were made to weather-normalize the revenues. Based on my review of the actual heating degree days ("HDD") and cooling degree days ("CDD") for 2012 through 2021, the HDD and CDD for 2021 were within a reasonable average range of the historical period once the outlier years were removed. Table 1 shows this comparison.

Table 1

Year	Annual Total HDD	CDD	Total
2012	3,739	774	4,513
2013	4,366	789	5,155
2014	4,522	764	5,286
2015	3,718	962	4,680
2016	3,833	1,086	4,919
2017	3,576	826	4,402
2018	4,044	1,185	5,229
2019	3,625	1,164	4,789
2020	3,614	990	4,604
2021	3,611	973	4,584
10 Yr. Avg.	3,865	951	4,816
Excluding Outlier Years:			
6 Yr. Avg.	3,690	992	4,682
Dif from 2021	(79)	(19)	(98)
% Dif from 2021	-2.1%	-1.9%	-2.1%

Q: PLEASE EXPLAIN YOUR ADJUSTMENTS RELATED TO THE NEW CAMPUS SUBSTATION.

A: NRLP installed a new campus substation, and it went into service as of June 2022. This new substation was required due to upgrades BREMCO made to its distribution system. As detailed in Exhibit REH-2A, the total cost of the new campus substation, including Allowance for Funds Used During Construction ("AFUDC"), is $2,952,679

As filed in NRLP's Petition for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses in Docket No. E-34, Sub 55, NRLP has requested the establishment of a regulatory asset and deferral of incremental post-in-service depreciation expenses and financing costs associated with this new substation. Exhibit REH-2B provides a calculation of the amortization expense in the amount of $107,793 related to the deferral request. This amount is based on the deferral of depreciation expense and the cost of capital as determined in Exhibit REH-2C and Exhibit REH-2D.

Next was the pro forma adjustment to increase Plant in Service by the cost of the new campus substation, including AFUDC through the date of commercial operation since it occurred after the test year. Depreciation expense was adjusted to reflect depreciation of the new campus substation, and accumulated depreciation was increased to account for the depreciation expense through July 31, 2023, the expected date of effective rates in this proceeding. The annual depreciation expense for the new campus substation, using a 33-year life, would be $89,475. The accumulated depreciation through July 31, 2023, would be $96,931. The adjustments discussed herein are reflected in Exhibit REH-13, the Proforma Adjusted Revenue Requirement.

Q: PLEASE EXPLAIN YOUR ADJUSTMENTS RELATED TO THE UNRELATED BUSINESS INCOME TAX.

A: As filed in NRLP's Petition for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses in Docket No. E-34, Sub 55, KPMG

LLP advised NRLP in a June 26, 2019, letter that NRLP is now subject to Federal and North Carolina State income tax on sales made to retail customers other than ASU and the Town of Boone. This reverses prior tax advice and thus has resulted in a liability for back taxes owed. A copy of this letter is included as Exhibit REH-24. NRLP has requested the establishment of a regulatory asset in the amount of $1,027,795 with an associated annual amortization expense of $342,598 for a three-year period. This results in an expense to be deferred in the amount of $685,197. These calculations are summarized in Exhibit REH-8 and the resulting adjustments are reflected in Exhibit REH-13, the Proforma Adjusted Revenue Requirement.

Q: PLEASE EXPLAIN YOUR ADJUSTMENTS RELATED TO THE LAYDOWN YARD.

A: NRLP completed the installation of a laydown yard that was in service as of July 2022. This laydown yard is located next to NRLP's warehouse where large inventory items such as poles and transformers are stored. It was a complete rebuild of previous structures that had reached the end of their useful and book life and required replacement.

First, it was necessary to increase Plant in Service by the cost of the laydown yard, including AFUDC through the date of commercial operation. Second, depreciation expense was adjusted to reflect depreciation of the laydown yard. Third, accumulated depreciation was increased to account for the depreciation expense through July 31, 2023, the expected date of effective rates in this proceeding .

As detailed in Exhibit REH-3, the total cost of the laydown yard, including AFUDC is $621,660. The annual depreciation expense -- using a 38.92 year life -- would be $15,973. The accumulated depreciation through July 31, 2023, would be $15,973. The adjustments discussed here are reflected in Exhibit REH-13, the Proforma Adjusted Revenue Requirement.

Q: PLEASE EXPLAIN YOUR ADJUSTMENTS RELATED TO THE SCADA SYSTEM.

A: NRLP completed the purchase and installation of a new supervisory control and data acquisition ("SCADA") system that was placed in service as of June 2022. The previous SCADA system was over 10 years old and would not work with NRLP's new automated metering infrastructure ("AMI") system. This new SCADA was needed to enable NRLP to realize the benefits of its AMI system. The old SCADA system was fully depreciated.

First, it was necessary to increase Plant in Service by the cost of the SCADA system, including AFUDC through the date of commercial operation.

Second, depreciation expense was adjusted to reflect depreciation of the SCADA system. Third, accumulated depreciation was increased to account for depreciation expenses through July 31, 2023.

As detailed in Exhibit REH-4, the total cost of the SCADA system, including AFUDC, is $214,173. The annual depreciation expense -- using a 13.92 year life -- would be $15,386. The accumulated depreciation through July 31, 2023, would be $16,668, the expected date of effective rates in this proceeding. The adjustments discussed here are reflected in Exhibit REH-13, the Proforma Adjusted Revenue Requirement.

Q: PLEASE EXPLAIN YOUR ADJUSTMENTS RELATED TO THE UNDERGROUND CONVERSIONS.

A: NRLP completed the installation of underground conversions that were in service as of July 2022. These areas used to have overhead power lines and have been converted to underground power lines because they experienced higher-than-system-average outages based on tree canopies and wildlife. The severe winter weather events (e.g. ice and/or snow, often accompanied by high winds) that can occur in Boone, and the necessity of electricity for heating during those events (when temperatures are often below freezing) magnify the need to minimize outages and the benefits of installing underground lines. The previous overhead power lines had been fully depreciated.

First, it was necessary to increase Plant in Service by the cost of the underground conversions, including AFUDC through the date of commercial operation. Second, depreciation expense was adjusted to reflect depreciation of these new underground conversions. Third, accumulated depreciation was increased to account for depreciation expense through July 31, 2023, the expected date of effective rates in this proceeding .

As detailed in Exhibit REH-5, the total cost of the underground conversions including AFUDC is $1,315,808. The annual depreciation expense using a 49.00 year life would be $26,853. The accumulated depreciation through July 31, 2023, would be $26,853. The adjustments discussed here are reflected in Exhibit REH-13, the Proforma Adjusted Revenue Requirement.

Q: PLEASE EXPLAIN YOUR ADJUSTMENTS RELATED TO THE WAREHOUSE.

A: NRLP completed the installation of an expansion and upgrade to the warehouse in July 2022. Additional space was required to include a new AMI metering shop and office space for field staff.

First, it was necessary to increase Plant in Service by the cost of the warehouse upgrade, including AFUDC through the date of commercial operation. Second, depreciation expense was adjusted to reflect depreciation of the warehouse upgrade. Third, accumulated depreciation was increased to account for depreciation expense through July 31, 2023, the expected date of effective rates in this proceeding.

As detailed in Exhibit REH-6, the total cost of the warehouse upgrade, including AFUDC, is $1,114,079. The annual depreciation expense -- using a 38.92 year life --would be $28,625. The accumulated depreciation through July 31, 2023 would be $26,625. The adjustments discussed here are reflected in Exhibit REH-13, the Proforma Adjusted Revenue Requirement.

Q: WHAT ADJUSTMENTS WERE MADE TO ACCOUNT FOR THE OLD CAMPUS SUBSTATION?

A: Since the old campus substation was decommissioned and removed from the Company's books in October 2021, the appropriate adjustments to depreciation expense and accumulated depreciation were accounted for in NRLP's 2021 financial statements.

The adjustments to account for the remaining asset value of the old campus substation are shown in Exhibit REH-7. Plant in Service as of October 27, 2021, included $625,592 for equipment that was removed from service as of this date. Accumulated depreciation on this equipment was $479,066 as of October 27, 2021, less cash received for scrap values of $26,000, which left a Net Plant in Service balance of $120,526.

NRLP is requesting regulatory asset treatment of the remaining unrecovered balance of the old campus substation to be amortized over a three year period. This would create an annual amortization expense of $40,175. Removing one year of annual amortization expense from the unamortized balance of $120,526 equals $80,351 to be included in rate base. This is consistent with the regulatory treatment approved by the Commission for the old meters in NRLP's prior rate case. The adjustments discussed here are reflected in Exhibit REH-13, the Proforma Adjusted Revenue Requirement.

Q: PLEASE EXPLAIN THE NEED FOR ADJUSTMENTS ASSOCIATED WITH SALARIES AND WAGES.

A: NRLP has had three general pay increase adjustments since December 31, 2021. The first occurred in January 2022 as a cost of living adjustment, the second occurred in July 2022 as a cost of living adjustment and the third was in September 2022 as part an adjustment to bring NRLP employees closer to the market-based salaries as compared to municipal utilities, according to a salary and wage study by ElectriCities of North Carolina. These salary and wage adjustments were necessary to reflect increases in the cost of living caused by inflation, and, more importantly, to enable NRLP to attract and retain qualified employees in a tight labor market and in light of increased competition by other employers.

Q: WHAT IS THE ADDITIONAL COST ASSOCIATED WITH THE SALARY INCREASES DISCUSSED ABOVE?

A: Exhibit REH-9 sets forth the adjustments made to salaries and benefits associated with the salary increases discussed above, as well as the additional costs from ASU Support Departments.

The salary-related expenses NRLP incurred from the ASU Support Departments for 2021 was $216,021. Based on a current assessment for ASU Support for NRLP's next fiscal year and moving forward, this amount has increased by $83,007 to a total annual cost of $299,028.

The NRLP total salaries for 2021 were $1,999,681. Based on the capital projects underway in 2021, some of these salaries were capitalized. This resulted in only $1,175,317 of salaries being expensed. Based on the salary adjustments discussed above, the total salaries for the next fiscal year will be $2,230,215. I propose to spread this increase of $230,534 over all NRLP employees according to the amount of salary expense each NRLP department had for the 2021 expenses salary line items. The adjustments discussed here are reflected in Exhibit REH-13, the Proforma Adjusted Revenue Requirements.

Q: WHAT ADJUSTMENTS WERE MADE TO PURCHASED POWER EXPENSE?

A: NRLP began receiving its wholesale power from Carolina Power Partners ("CPP") as of January 1, 2022. To reflect this new power supply arrangement, the purchased power cost for Test Year 2021 was calculated using the contracted capacity charges NRLP has with CPP and the passthrough costs of energy from CPP based on an average cost of natural gas of $5.16 per MMBtu. The actual average cost of natural gas in 2021 was $3.99 per MMBtu. Given the current volatility of the natural gas market, the need for NRLP's significant increases in the Purchased Power Adjustment Clause rates and forward gas curves being higher than the cost of gas in 2021, the use of $5.16 per MMBtu is a reasonable modification to NRLP's cost of energy that would be included as part of NRLP's Base Rates moving forward.

The other components of NRLP's purchased power costs are for Duke Energy Carolina ("DEC") transmission services and BREMCO distribution services. Exhibit REH-12 summarizes these costs monthly, totaling an annual cost of $14,930,090. This calculation shows an increase of annual purchased power costs in the amount of $4,398,413 as summarized in Exhibit REH-13 on Line 47. NRLP's actual cost of purchased power in 2021 was $10.514 million which included a one-time billing credit of $2.374 million for overcharges in 2020 from DEC. Excluding this billing credit, NRLP's cost of purchased power was $12.888 million.

Q: WILL NRLP BE SUBJECT TO ANY MORE COAL ASH RECOVERY COSTS FROM DUKE ENERGY CAROLINA?

A: No. Since NRLP no longer receives its wholesale power from DEC, NRLP will no longer be charged coal ash-related expenses from DEC.

Q: WHAT ADJUSTMENTS WERE MADE TO OPERATING EXPENSES TO ACCOUNT FOR INFLATION?

A: The utility industry has been impacted by the increased cost of operations due to the nation's inflationary pressures. To accommodate for these increased costs, those operating expense items not adjusted from any of the proforma adjustments discussed above were escalated by the Consumer Price Index ("CPI"). The annual CPI for the twelve months ending September 30, 2022, was 6.6%. Converting this annual percentage to a monthly factor and applying it to the unadjusted operating expenses generates an additional $240,411 through July 31, 2023. These calculations are summarized in Exhibit REH-10. The adjustments discussed here are reflected in Exhibit REH-13, the Proforma Adjusted Revenue Requirements.

Q: WHAT ADJUSTMENTS WERE MADE TO ACCOUNT FOR NRLP'S UBIT EXPENSES?

A: As previously mentioned, NRLP must pay taxes on revenues to retail customers other than ASU and the Town of Boone. The following Table 2 summarizes the calculations used to establish the on-going UBIT expenses for the Test Year revenue requirement.

Table 2

Description	Amount
Net Income BeforeTaxes	$ 2,139,050.97
Non ASU & TOB Usage (per KMPG)	73.21%
Taxable Net Income	$ 1,565,999.22
Federal Tax Rate	21.00%
NC State Tax Rate	2.50%
UBIT	$ 368,009.82

This UBIT amount is included on Line 229 of Exhibit REH-13.

Q: WHAT IS THE CUMULATIVE IMPACT OF ALL ADJUSTMENTS MADE TO THE TEST YEAR REVENUE REQUIREMENTS?

A: As summarized on Line 230 of Exhibit REH-13, The total adjustments amount to an additional $6,853,575, for a total revenue requirement to recover from base rates of $23,253,014.

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND REGULATORY POLICY CONSIDERATIONS THAT SUPPORT YOUR RECOMMENDED FAIR RATE OF RETURN THAT NRLP SHOULD BE ALLOWED THE OPPORTUNITY TO EARN.

A. A prudently managed utility should be allowed to charge prices that allow the utility the opportunity to recover the reasonable and prudent costs of providing utility service, including a fair rate of return on invested capital. This fair rate of return on capital should allow the utility, under prudent management, to provide adequate service and obtain capital to meet future equipment replacement, improvement, and expansion needs in its service area. Since electric utilities are capital-intensive businesses, the cost of capital is a crucial issue for utility companies, their customers, and regulators. If the allowed rate of return is set too high, then consumers are burdened with excessive costs, current owners receive a windfall, and the utility has an incentive to overinvest. If the return is set too low, adequate current and future service is jeopardized because the utility will not be able to raise new capital on reasonable terms.

Since every equity owner faces a risk-return tradeoff, the issue of risk is an important element in determining the fair rate of return for a utility.

Regulatory law and policy recognize that utilities compete with other firms in the market for investor capital. In the case of Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), the U.S. Supreme Court recognized these fundamental principles and provided legal and policy guidance concerning the return that public utilities should be allowed to earn:

> [T]he 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.

(320 U.S. at 603)

Q: WHY DO THESE PRINCIPLES APPLY TO NRLP AS A STATE-RUN UTILITY THAT DOES NOT HAVE PUBLICLY TRADED STOCK?

A: While NRLP is a state-run utility that does not have publicly traded stock, the application of the principles for determining the appropriate rate of return for publicly traded utilities applies because ASU must obtain capital to continue reliable service by the utility. A portion of the capital investment is made from debt financing with a contractually determined cost of capital. In addition, NRLP also uses retained earnings to finance capital improvements. NRLP should be allowed a weighted average cost of capital that includes a component at an appropriate risk-based cost of equity. Otherwise, the retained earnings will be diminished, the need to rely on debt will increase, and the capital structure could become imbalanced in a way that increases risk. The Commission has traditionally recognized this reality in approving NRLP's rate of return on equity in all prior rate cases. *See, e.g.* Docket No. E-34, Sub 46, Order dated March 29, 2018, Finding 29 (9.25%); Docket No. E-34, Sub 32, Order dated May 1, 1997, Finding 9 ("11.0%"); Docket No. E-34. Sub 28, Order dated Feb. 19, 1991, Finding 10 ("12.0%).

Q. HOW DO REGULATORY AUTHORITIES DETERMINE A FAIR RATE OF RETURN ON EQUITY FOR USE IN RATE CASES?

A. Regulatory commissions use different analytical models and methodologies to establish reasonable rates of return on equity ("ROE"). In many cases, the Discounted Cash Flow analysis and Comparable Earnings Analysis ("CEA") are used to support a reasonable return on equity. In the current case, I looked only at CEA.

Q. WHY ARE YOU NOT DEVELOPING A DISCOUNTED CASH FLOW ANALYSIS FOR NRLP?

A. To reduce the rate case expenses and simplify the preparation of the rate case filing of NRLP, NRLP has decided to rely on previous ROEs approved by the NCUC for comparable utilities in North Carolina in our first analysis, overall allowed returns in the electric sector in our second analysis, and earned returns across the electric sector in our third analysis.

Q. WHAT NORTH CAROLINA UTILITIES ARE YOU USING FOR THE ROE COMPARISON IN YOUR FIRST ANALYSIS?

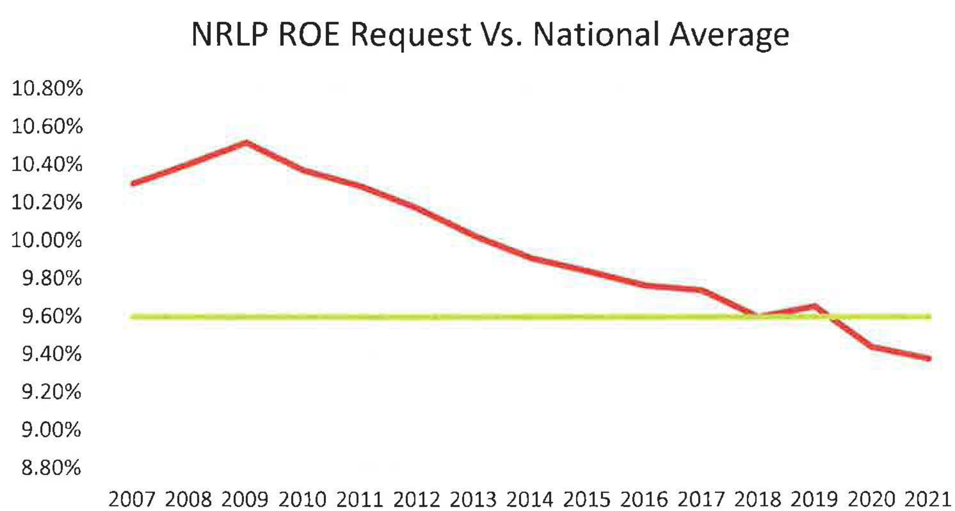
A. I use two recently approved ROEs from natural gas distribution utilities: Piedmont Natural Gas Company, decided on January 6, 2022, in Docket No. G-9, Sub 781, and Public Service Company of North Carolina, decided on January 21, 2022, in Docket No. G-5, Sub 632. These two utilities are similar to NRLP in that they are also distribution-only utilities. In that important respect, they have risk profiles similar to that of NRLP, and therefore their approved ROEs would be a reasonable guide for the ROE for NRLP. In both Dockets, a 9.60% ROE was approved. Although investor risk, and thus ROE, has increased over the past twelve months, this 9.60% represents a reasonable, albeit conservative, ROE for NRLP.

Q. PLEASE DESCRIBE YOUR SECOND CEA ANALYSIS.

A. Because the availability and flow of capital for utility operations in the United States is a national (or even international) market, it is important to understand what state regulatory commissions/boards across the country are allowing for authorized ROEs. Allowed ROEs are widely known and discussed in the financial community and investors take these regulatory decisions into account when they consider the price to purchase equity, or the terms under which they will invest, in a regulated utility.

As this Commission is likely aware, regulated ROE's have generally trended down over the past 15 years. Below, Table 3 shows the ROEs authorized for electric utilities by state regulators across the United States from 2007 through 2021, which ranges from 9.38% (2021) to 10.52% (2009).

Table 3: Allowed ROEs 2007 – 2021[1]



[1] *S&P Global Market Intelligence* Rate Case Statistics; Date Range: 15 Years; Service Type: Chart Items: Common Equity to Total Capital, Return on Equity; Date Accessed: August 11, 2022.

As for the most recent year, 2021, the overall allowed ROE for electric utilities was 9.38%, which is the lowest figure over the previous 15-year period. These economic variables, however, are cyclical, and as we all know, interest rates (as the returns of fixed-income investments as alternatives to equity) have increased over the past year. Therefore, we expect the allowed ROEs to end their decline downward and to now move back upward.

Q. PLEASE EXPLAIN YOUR THIRD CEA ANALYSIS.

A. In my third analysis, I examined electric utilities' returns as reported by the Value Line Investment Survey. I examined their earned ROEs from 2020 through 2027E. The results are in Table 4 below:

Table 4: Earned Returns per Value Line[2]

Company	2020	2021	2022E*	2023E*	2025-27E*
Amer Elec Power	10.7%	11.1%	11.0%	10.5%	11.0%
ALLETE	7.6%	7.0%	7.5%	8.0%	9.0%
Alliant Energy	10.8%	11.0%	11.0%	11.5%	11.5%
Ameren Corp	9.7%	10.2%	10.0%	10.0%	10.0%
Avangrid Inc	4.1%	4.1%	4.5%	4.5%	5.0%
Avista Corp	6.4%	6.8%	6.5%	7.5%	8.0%
Black Hills Corp	9.1%	8.5%	8.0%	8.0%	9.0%
CenterPoint Energy Inc	11.6%	6.7%	9.5%	10.0%	10.0%
CMS Energy Corp	13.7%	11.6%	12.5%	13.0%	13.0%
Consol Edison	7.4%	7.6%	8.0%	8.0%	8.0%
Dominion Energy	12.7%	12.5%	12.5%	12.5%	13.0%
DTE Energy Co	11.0%	9.1%	9.0%	11.5%	12.5%
Duke Energy	8.2%	8.5%	8.5%	9.0%	9.0%
Edison Int'l	4.6%	5.5%	13.0%	13.0%	13.0%
Entergy Corp	12.7%	11.9%	11.0%	10.5%	11.5%
Evergy Inc.	7.1%	9.5%	8.5%	9.0%	10.0%
Eversource Energy	8.8%	9.1%	9.0%	9.5%	10.0%
Exelon Corp	9.7%	8.0%	9.5%	9.5%	10.0%

[2] The Value Line Investment Survey: 9/9/2022 (Electric Utilities Central), 10/24/2022 (Electric Utilities West), and 11/11/2022 (Electric Utilities East)

Hawaiian Elec	8.5%	10.3%	8.5%	8.5%	9.0%
IDACORP Inc	9.3%	9.2%	9.0%	9.0%	9.0%
NextEra Energy	12.5%	13.5%	15.0%	13.5%	15.0%
NorthWestern Corp	7.8%	7.8%	7.5%	7.5%	8.0%
OGE Energy	11.5%	11.6%	12.0%	12.0%	13.0%
Otter Tail Corp	11.0%	17.8%	19.5%	13.5%	11.5%
Pinnacle West Capital	9.8%	10.5%	7.5%	8.0%	9.0%
PNM Resources	8.9%	9.7%	9.5%	9.5%	9.5%
Portland General	9.5%	9.0%	9.0%	9.0%	9.5%
PPL Corp	11.7%	2.9%	7.0%	7.0%	7.5%
Public Serv Enterprise	10.9%	12.8%	13.0%	12.5%	13.0%
Sempra Energy	10.6%	10.5%	10.5%	10.5%	11.0%
Southern Co	12.4%	13.1%	13.0%	13.0%	14.5%
WEC Energy Group	11.5%	11.9%	12.5%	12.5%	13.0%
Xcel Energy	10.1%	10.2%	10.5%	10.5%	11.0%
Fortis Inc	7.1%	7.0%	7.0%	7.0%	7.5%
AVERAGE	**9.7%**	**9.6%**	**10.0%**	**10.0%**	**10.4%**
*E = expected					

As can be seen in the above table, the requested ROE of NRLP is equal to or below the average past/estimated earned returns on common equity for all utility holding companies followed by Value Line.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR THREE CEA ANALYSIS?

A. Based on the above-stated findings, I believe the proper rate of return using a CEA is in the range of 9.50% to 10.00%. The 9.50% low end of this range is placed between the 2021 ROE granted by state regulators of 9.38% and the average ROE granted by state regulators over the previous 15-year period of 9.96% (see Table 3). The 10.00% high end of the range is the expected earned return for the electric utility industry in 2022 and 2023 per Value Line.

Q. WHAT IS YOUR ROE RECOMMENDATION IN THIS CASE?

A. Based on the three CEA analyses discussed above, I am recommending 9.60% as the appropriate ROE for NRLP.

Q. WHAT CAPITAL STRUCTURE DOES NRLP CURRENTLY MAINTAIN?

A. NRLP has very little debt and, what debt it does have, is at a very low embedded cost of debt. Retained earnings are the source of equity capital. NRLP's current capital structure is summarized in Table 5.

Table 5: 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. ARE YOU RECOMMENDING THE ACTUAL NRLP CAPITAL STRUCTURE IN THIS CASE?

A. No. Common equity has a higher cost of capital than debt. As a result, a capital structure composed of 78% or more common equity would be too high and unfair to NRLP's consumers. It's worth noting, however, that in some of the previous NRLP rate cases, the Commission did approve the actual capital structure. *See* Docket No. E-34, Sub 32, Order dated May 1, 1997, Finding 9 ("capital structure of 6.42 debt and 93.58.% equity");

Docket No. E-34. Sub 28, Order dated Feb. 19, 1991, Finding 10 ("capital structure of 6.58% debt and 93.42% equity). So there would be precedent for using the actual capital structure.

In general, Commissions across the country have granted overall rates of return based on capital structures that are comprised of roughly 50% common equity. The two natural gas distribution utilities discussed above settled on a capital structure using 51.6% for equity.

Q. WHAT IS YOUR RECOMMENDED CAPITAL STRUCTURE IN THIS PROCEEDING?

A. I am recommending a capital structure that consists of 52% equity and 48% debt, which is comparable to that authorized for the two natural gas distribution utilities discussed above.

Q. SINCE NRLP HAS VERY LITTLE DEBT, HOW DO YOU DETERMINE THE PROPER COST OF DEBT TO USE IN THE NRLP REQUESTED CAPITAL STRUCTURE?

A. If NRLP were to seek additional debt financing to meet the 52% equity/48% debt capital structure I am recommending herein, the cost of debt would be higher than the embedded rate on existing debt. It would be reasonable to estimate these debt costs by looking at other current costs of debt. This can be obtained by reviewing other debt cost rates approved by this Commission as well as the current debt cost rate in the utility industry.

A hypothetical or imputed cost of debt is especially reasonable where the amount of debt in the capital structure is changed for ratemaking purposes from 21.7% actual to 48% hypothetical. Use of the actual cost of debt with a hypothetical 48% capital structure amount of debt would unfairly depress the weighted average cost of capital.

Q. WHAT COST OF DEBT HAS RECENTLY BEEN APPROVED BY THIS COMMISSION THAT HAS A CAPITAL STRUCTURE COMPARABLE TO NRLP?

A. The Commission approved a long-term debt cost rate of 4.37% and 4.02% for Public Service Company of North Carolina and Piedmont Natural Gas Company, respectively, in the dockets referenced above. The average of these two approved costs of debt is 4.20%. This cost of debt would also recognize the current increases in borrowing costs throughout the country.

Q. WHAT IS YOUR RECOMMENDED COST OF DEBT IN THIS CASE?

A. Based on what the Commission approved in early 2022 for the two major gas distribution utilities in North Carolina, I believe a reasonable cost of debt for use in this case is 4.20%.

Q. WHAT IS YOUR RECOMMENDATION FOR THE RETURN ON EQUITY AND OVERALL RATE OF RETURN THE COMMISSION SHOULD USE IN THIS PROCEEDING?

A. My recommended overall cost of capital is in Table 6 below.

Table 6: NRLP Recommended Overall Cost of Capital

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

Q: DID YOU DEVELOP AN ALLOCATED COST OF SERVICE ANALYSIS TO DETERMINE THE COSTS OF PROVIDING SERVICE TO EACH RATE CLASS?

A: Yes. The allocated cost of service is included in Exhibit REH-14.

Q: WHAT IS THE PURPOSE OF AN ALLOCATED COST OF SERVICE ANALYSIS?

A: The cost to provide electric service varies among the different rate classes, so a common ratemaking principle is to determine reasonable rates for each class on the basis of that class's allocated share of the overall cost of service. While rates can never be 100% cost-based because there are so many variables from customer-to-customer and from time-to-time, the use of cost-based rates by customer class is an important part of establishing non-discriminatory rates. An allocated cost of service analysis is used to determine the costs for each customer class, which then inform the setting of rates for each customer class. Those costs include expenses to own, operate and maintain a utility system, as well as a return of investment through depreciation and a return on investment in facilities required to provide service. Resulting rates should provide a fair and reasonable return.

Q: ARE THERE OTHER TOOLS USED BY UTILITY MANAGERS TO DETERMINE THE APPROPRIATE LEVEL OF RATES?

A: Yes. An allocated cost of service analysis is based on allocation of costs using allocation factors which are determined to be "cost-causative." The methods used to allocate costs are based on the judgment of the analyst in developing the study. Other factors that are often considered before changing rates, include comparison of rates to other utilities in the area, impact of rate changes on customers, sending price signals to incentivize customers' usage behavior, gradualism in changing rates for a class that is a long way from paying for its allocated cost of service, and the complexity of the rate design.

Q: PLEASE DESCRIBE HOW YOU DEVELOPED THE ALLOCATED COST OF SERVICE ANALYSIS FOR NRLP.

A: The allocated cost of service analysis was based on the total system revenue requirements previously discussed above. I allocated each component of the revenue requirement by cost-causative factors which included number of customers, energy, and several demand allocators.

- Customer Specific – This allocation assigns a line-item expense directly to a single customer class, if warranted.
- Energy – Annual Test Year energy consumption from each customer class was used to allocate expense items related to the variable nature of consuming energy.

NRLP was able to use more accurate billing data for this rate proceeding than in its last rate proceeding due to data collected from its AMI system. Detail billing data was available to identify accurate allocation factors for various components of the cost of service analysis. NRLP worked with its AMI vendor, Nexgrid, to provide the following information by customer class for the period January 1, 2021, through December 31, 2021, from the load data collected through NRLP's AMI system:

- Coincident Peak Demand (CPP Wholesale): Sum of the kW demands coincident with the monthly peak demands of CPP for each month of 2021. This is used to allocate the capacity portion of CPP's purchased power costs.

- Coincident Peak Demand (DEC Transmission): Sum of the kW demands coincident with the monthly peak demands of DEC for each month of 2021, This is used to allocate the DEC transmission service costs.
- Coincident Peak Demand (BREMCO Distribution): Sum of the kW demands coincident with the monthly peak demands of BREMCO for each month of 2021. This is used to allocate the BREMCO distribution service costs.
- 20 Coincident Peak Demand (BREMCO True-Up): Sum of the kW demands coincident with the 20 highest summer hours of 2021 demand for DEC. This is used to allocate a true-up mechanism within the BREMCO distribution service charges.
- Coincident Peak Demand (NRLP): Sum of the kW demands coincident with the monthly peak demands of NRLP for each month of 2021. This is used to allocate some of the distribution costs of NRLP.
- Customer Class Coincident Peak Demand: Sum of the kW demand coincident with each customer class's peak demand by month for 2021. This is used to allocate some of the distribution costs of NRLP.

- Number of Customers – The average number of customers by class for the Test Year was used to develop an allocation factor for expense items related to servicing customers.
- Weighted Customers – Other customer-related factors were developed using demand and energy as a weighting component to provide an allocation for some items that involve demand and customer expenses.

Q: **WHAT IS THE TOTAL REVENUE REQUIREMENT?**

A: As previously discussed, the overall Base Rate annual revenue requirement is $23,221,543. This revenue requirement already includes an offset of $257,297 for Other Operating Revenues.

Q: **WHAT ARE THE TOTAL REVENUES AT PRESENT RATES?**

A: The present Base Rates provide annual revenues of $18,596,795.

Q: HOW DID YOU DETERMINE THE REVENUES UNDER CURRENT RATES?

A: Revenues for the 2021 historical Test Year were provided by NRLP as shown in the 2021 financial statements. These reported revenues account for the accrual process and include PPAC and CACR rate revenues. The actual billing determinants (number of customers, customer demand and customer electric usage) for the 2021 Test Year were applied to NRLP's current Base Rates to provide current base rate revenues to compare against the cost-of-service revenue requirements.

Q: DOES NRLP EXPECT ADDITIONAL REVENUES IN THE RATE YEAR DUE TO THE PPAC?

A: Yes. Based on NRLP's current PPAC preliminary filing under Docket No. 34, Sub 55, NRLP is estimating retail customer increases between 23% and 31% for rates effective March 1, 2023. This is in addition to roughly the same level of increase passed to NRLP retail customers for a midyear PPAC effective August 1, 2022. These significant PPAC increases are required due to the significant increase and volatility of the cost of natural gas used to generate energy from CPP.

Q: IS NRLP PROPOSING ANY CHANGES TO ADDRESS THIS WHOLESALE POWER SUPPLY PRICE VOLATILITY?

A: Yes, but not as a part of this rate case proceeding. NRLP is evaluating its ability to modify the PPAC on a more frequent basis than its typical annual process. The rate shock that NRLP's retail customers are experiencing could be reduced if the effects of changing prices of natural gas could be phased in as the costs are incurred. This not only stabilizes the rate impact to NRLP customers, it also would significantly reduce the negative cash flow NRLP incurs as these natural gas prices increase without increasing the PPAC accordingly. NRLP plans to request a change in the PPAC calculations as part of its PPA update filing in Docket No. E-34, Sub 56, in January 2023.

Q: WHAT IS THE TOTAL REVENUE DEFICIENCY AT PRESENT RATES?

A: Comparison of the revenue requirement to the revenues at present rates indicates a revenue deficiency of $4,624,749 as summarized on Line 240 of Exhibit REH-13. This translates to an overall system Base Rate revenue increase of 24.87%. Since this Base Rate increase includes a higher purchased power cost, the projected PPAC revenues would be reduced by $2,026,356. This results in a net overall system rate increase of 13.97%

Q: PLEASE SUMMARIZE THE RESULTS OF YOUR COST OF SERVICE ANALYSIS.

A: The cost of service analysis allocated the detail line-item costs that make up the total system revenue requirement. This detailed analysis is included as Exhibit REH-14. Table 7 summarizes the result of the cost of service analysis for Base Rates.

Table 7: Summary of Cost of Service Analysis

Class	Total Base Rate Revenue Requirement	Total Current Base Rate Revenues	Revenue Deficiency
Total System	$23,221,543	$18,596,795	$4,624,749
Residential	$7,776,098	$6,659,874	$1,116,225
Commercial Non-Demand	$2,934,706	$2,322,088	$612,617
Commercial Demand	$8,098,660	$5,758,770	$2,339,889
ASU Campus	$4,091,020	$3,625,006	$466,015
Security Lighting (Excluding Investment)	$321,059	$231,057	$90,003

It should be noted that the Security Lighting revenue requirement and current rate revenues summarized above and in the cost-of-service analysis only account for the Security Lighting rate class's allocated share of O&M and purchased power. The lighting charges that will recover the investment portion of the lighting are developed and discussed further below.

Q: WHAT IS THE EFFECTIVE RATE INCREASE FOR EACH CUSTOMER CLASS BASED ON THE COST OF SERVICE MODEL SUMMARIZED ABOVE?

A: Table 8 provides the summary of each customer class's Base Rate increase.

Table 8: Summary of Required Rate Increase based on Cost of Service

Class	Percentage Base Rate Increase	Percentage Net Rate Increase Accounting for PPAC
Total System	24.87%	13.97%
Residential	16.76%	7.58%
Commercial Non-Demand	26.38%	16.51%
Commercial Demand	40.63%	28.16%
ASU Campus	12.86%	0.68%
Security Lighting (Excluding Investment)	38.95%	27.67%

Q: DOES THE COST OF SERVICE MODEL PROVIDE THE DETAIL OF HOW EACH CUSTOMER CLASS INCURS ITS COSTS?

A: Yes, with detail from the cost of service model, a summary of the allocation for each customer class's cost can be identified for the following categories: 1) NRLP Distribution Related, 2) BREMCO Distribution Related, 3) DEC Transmission Related, 4) CPP Production Demand Related, and 5) CPP Production Energy Related. Exhibit REH-22 provides this summary of costs.

Using the cost classifications from Exhibit REH-22, an average monthly cost per customer can be developed to demonstrate the level of fixed costs required to provide electric service to NRLP retail customers. Exhibit REH-

23 summarizes these monthly customer costs. This type of information is considered when designing rates for each customer class.

Q: HOW ARE YOU PROPOSING TO MOVE EACH CUSTOMER CLASS CLOSER TO ITS ALLOCATED SHARE OF TOTAL SYSTEM COST RECOVERY?

A: My recommended rate adjustments are based on rate design principles articulated by the Public Staff in testimony as recognized by the Commission:

> Public Staff witness Floyd testified that the Public Staff believes that assignment of a proposed revenue change, whether it is an increase or a decrease, should be governed by four fundamental principles. Using the ROR [rate of return for each class] as determined by the COSS [cost of service study], and incorporating all adjustments and allocation factors associated with the proposed revenue change, the Public Staff seeks to:
>
> (1) Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
>
> (2) Maintain a +/-10% "band of reasonableness" for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;
>
> (3) Move each customer class toward parity with the overall jurisdictional ROR; and

(4) Minimize subsidization of customer classes by other customer classes.

See, e.g, Docket No. E-7, Sub 1214 (March 31, 2021, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice).

Since the commercial customer classes require a sizable adjustment to reach their allocated share of total system revenue requirements, I propose a two-year phase-in of base rate adjustments.

Exhibit REH-15 utilizes these principles to provide for a two-year phase-in to cost-based rates while ensuring the total system revenue requirements are recovered by NRLP.

Exhibit REH-16 is the rate design model used to develop rates for the year-one parameters developed in Exhibit REH-15.

Q: ARE THERE ANY PROPOSED BASE RATE STRUCTURE MODIFICATIONS WITHIN EACH CUSTOMER CLASS FOR THE FIRST YEAR OF THE RATE PHASE-IN?

A: Yes. The following will summarize the Base Rate structure modifications:

- General Structure Modification – Within each customer rate classification, the charges specific to recovering NRLP's distribution system costs will be itemized separately. This will allow NRLP to differentiate the costs in providing the distribution service to its customers from the wholesale purchased power costs that are a passthrough to its customers.
- PPA Rate Modification – Since the Base Rate revenue requirements have been adjusted to include an increased cost of purchased power, this will result in a decrease of incremental PPA rate revenues. The existing Base Rates include a purchased power cost of $0.062846 per kWh and this resulted in a PPA charge of $0.045753 as filed in NRLP's preliminary PPA adjustment in Docket No. E-34, Sub 56. Based on the updated purchased power costs for this rate proceeding, the purchased power costs included in the proposed Base Rates is $0.072692 per kWh which would result in a PPA charge of $0.035893 per kWh. These calculations can be found in Exhibit REH-21.
- Residential Service – The Basic Facilities Charge is proposed to increase from $12.58 to $14.50 per month, which is still well below the residential monthly fixed cost of $36.00 as shown in Exhibit REH-23. The current energy rate will change from $0.090044 per kWh to $0.032593 per kWh for the NRLP Distribution Charge and

$0.080008 per kWh for the Wholesale Power Supply Charge. The PPA energy charge will decrease from $0.045753 per kWh to $0.035893 per kWh.

- Commercial Non-Demand – The Basic Facilities Charge is proposed to increase from $17.42 to $17.50 per month. The current energy rate will change from $0.086683 per kWh to $0.032656 per kWh for the NRLP Distribution Charge and $0.080309 per kWh for the Wholesale Power Supply Charge. The PPA energy charge will decrease from $0.045753 per kWh to $0.035893 per kWh.
- Commercial Demand Service – The Basic Facilities Charge is proposed to increase from $23.22 to $30.00 per month. The current demand rate will change from $8.27 per kW to $2.27 per kW for the NRLP Distribution Charge and $6.00 per kW for the Wholesale Power Supply Charge. The current energy rate will change from $0.054222 per kWh to $0.021586 per kWh for the NRLP Distribution Charge and $0.053429 per kWh for the Wholesale Power Supply Charge. The PPA energy charge will decrease from $0.045753 per kWh to $0.035893 per kWh.
- Commercial Demand High Load Factor Service – This customer classification will be removed from NRLP's rate schedules. Based on review of AMI data during the development of cost of service allocation factors, it was determined that was not enough difference

in customer usage characteristics to warrant customers being placed on this classification. NRLP currently does not have any customers receiving service under this rate schedule so there is no adverse impact to any customers from the removal of this rate schedule.

- ASU Campus Service – The rate design for ASU was modified during the 2017 rate case to collect NRLP distribution costs and wholesale power supply costs in separate charges. This was done to ensure all of NRLP's fixed costs would be collected from ASU as they considered various onsite generation options. The Distribution Facilities Charge is proposed to increase from $10.63 per kW to $18.03 per kW. The Power Demand Charge is proposed to decrease from $8.75 per kW to $8.56 per kW. The Wholesale Power Energy Charge is proposed to increase from $0.040950 per kWh to $0.044428 per kWh. The PPA energy charge will decrease from $0.045753 per kWh to $0.035893 per kWh.
- Lighting Service – The proposed charges for lighting service include two components; (1) the allocated share of O&M and purchased power costs from the cost of service model and (2) the investment charge required to reimburse NRLP for the cost of the equipment with a return equal to cost of capital established above. Exhibit REH-17 provides the detail of NRLP's investment in current lighting equipment for traditional and LED lighting services. The

proposed lighting charges in Exhibit REH-16 include both the O&M/purchased power charges and the investment charges. Exhibit REH-18 was developed to provide a comparison of how the existing lighting charges would be divided between investment and O&M/purchased power charges. It should be noted that the Town of Boone lighting charges are for the O&M/purchased power charges only since the Town pays for the capital costs of the lights upfront at the time of installation.

Q: IS NRLP PROPOSING ANY ADDITIONAL RATE RIDERS?

A: Yes. NRLP is proposing a Net Billing Rate Rider as a new option for customers with photovoltaic (PV) renewable energy generation installed on their premises as well as modifying its avoided cost for PV renewable generation. NRLP is also proposing an Interruptible Rate Rider for customers that have the ability to curtail their electric usage.

Q: HOW DOES NRLP ENSURE THAT THERE ARE NO CROSS SUBSIDIES OR DISCRIMINATORY RATES WITH ITS PROPOSED NET BILLING RATE RIDER?

A: The proposed Net Billing Rider was developed following the criteria established under N.C.G.S. § 62-126.4. Hourly load data for 2021 from each of NRLP's customers that currently have PV renewable generation was evaluated to determine the actual costs that NRLP avoided when these units were generating energy. Since NRLP's distribution system costs are fixed in nature, these PV generation facilities did not reduce any of NRLP's distribution costs.

Q: ARE THERE SOME COSTS THAT ARE OFFSET BY GENERATION AT THE CUSTOMER'S PREMISES?

A: Yes, based on the evaluation previously described, it was determined that these PV facilities did offset a portion of NRLP's costs from CPP demand charges, CPP energy charges, DEC transmission charges and BREMCO distribution charges. As summarized in Exhibit REH-19A, the PV facilities were generating at approximately 29% of their maximum output during the times of BREMCO and DEC coincident peak hours and approximately 26% during CPP's coincident peak hours. Since NRLP is charged based on its coincident peak demand for BREMCO, DEC and CPP demand related costs, these PV facilities did reduce NRLP's demand related costs and this benefit should be passed on to these customers owning PV generation.

Exhibit REH-19A also shows the costs that NRLP would not avoid and calculates a monthly charge of $6.17 per kW that would be assessed to the name plate capacity of the PV facilities installed on the customer's premises. This monthly charge effectively recovers NRLP's fixed costs that these customers would have paid without their PV generation, reducing the amount of energy purchased from NRLP.

Q: BASED ON YOUR FINDINGS FROM THE NET BILLING RATE RIDER, ARE YOU PROPOSING ANY CHANGES TO NRLP'S AVOIDED COST?

A: Yes. As discussed in the Net Billing Rider above, NRLP does avoid a portion of its BREMCO, DEC and CPP demand related costs from the PV generation. These same percentage reductions in demand are summarized in Exhibit REH-19B to generate an avoided cost of $0.089039 per kWh. Therefore, NRLP is proposing to modify its avoided cost rate for PV generation to $0.089039 per kWh

Q: HOW DOES NRLP PROPOSE ITS INTERRUPTIBLE RATE RIDER WILL WORK?

A: Based on NRLP's Power supply agreement with CPP, its monthly capacity cost is based on NRLP's demand at the time of the CPP customer group peak. If a customer is successful in interrupting its service during these times, the customer would not be contributing to NRLP's capacity during these months. Therefore, NRLP is proposing a monthly credit of $14.26 for the customer's reduction of demand during the CP hour. This rider would be available to any customer with a kW demand of 2 MW or greater and has the ability to curtail at least 75% of its electrical load. Exhibit REH-20 summarizes the structure of this proposed Interruptible Rate Rider.

Q: DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does, at this time.

SUMMARY OF DIRECT TESTIMONY OF RANDALL HALLEY

ON BEHALF OF NEW RIVER LIGHT & POWER

DOCKET NO. E-34, SUBS 54 & 55
JULY 10, 2023

My direct testimony reflects the position of New River Light & Power prior to settlement with the Public Staff, so the following summary has to some extent been superseded.

I recommended that the rate of return for New River be set at 7.007%. This return is based on an imputed capital structure of 52% equity and 48% long term debt, an imputed debt cost of 4.20%, and a rate of return on common equity of 9.60%. These debt and equity costs rates were derived from the two most recent Commission decisions for distribution utilities in North Carolina.

The requested increase in annual revenue requirement in base rates was $4,624,749. When netted with a proposed decrease in the Purchased Power Adjustment Clause revenues from a reallocation of purchased power costs, the net proposed increase in base rates was $2,598,393. This request was the result of the revenue requirement for the calendar 2021 test year with pro forma adjustments listed in my testimony that increased the revenue requirement.

An allocated cost of service study was conducted to inform the rate design. An important part of rate design is to have rates for each customer class that reflect the costs to provide service to each customer class. Some classes overpay their costs, and some underpay their costs, so the proposed rates are meant to move the customer classes closer to paying their fair share.

New River is proposing a new Net Billing Rider for customers who have photovoltaic renewable energy generation connected to the New River grid and would like the ability to use this renewable energy. The Net Billing Rider is designed to avoid cross subsidies from non-participating customers. New River proposes a second option for customers to sell all their photovoltaic renewable energy to New River through a new Schedule PPR for Purchased Power from Renewable Energy Facilities. New River also proposes an Interruptible Rider for customers who curtail usage during the coincident peak times of New River's wholesale power provided.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-34, SUB 54
DOCKET NO. E-34, SUB 55

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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	**PRE-FILED REBUTTAL** **TESTIMONY OF** **RANDALL E. HALLEY**

June 23, 2023

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Randall E. Halley. I am a Managing Principal with Summit Utility Advisors, Inc. ("Summit"). My business address is 7614 Lake Drive, Orlando, Florida 32809.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Applicant, Appalachian State University ("ASU") d/b/a New River Light and Power ("NRLP").

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the prefiled testimony of the following witnesses in these dockets:

- Testimonies of Jack Floyd and John R. Hinton and Joint Testimonies of Sonja R. Johnson and Iris Morgan, witnesses for the Public Staff of the North Carolina Utilities Commission ("Public Staff");
- Testimonies of Jason W. Hoyle and Justin R. Barnes for Appalachian Voices.

In addition, I present certain revisions to my direct testimony and exhibits.

II. REVISIONS TO DIRECT TESTIMONY AND EXHIBITS

Q. Why are you submitting revisions to your direct testimony and exhibits?

A. The revisions are in response to matters raised in discovery with the other parties, review of the testimony of the other parties, and discussion with the other parties. This is discussed in more detail below.

Q. Please list your revisions based on the Public Staff's testimony.

A. NRLP has made several changes in response to Public Staff recommendations. These changes are to NRLP's revenue requirement and rate design. The modifications to revenue requirement include the following:

a) Removal of non-utility revenues and expenses.

b) Adjusted materials and supplies included in rate base.

c) Adjusted prepaid expenses included in rate base.

d) Adjusted working capital included in rate base.

e) Adjusted regulatory fee from reduction of revenue requirement.

The modifications to rate design based on discussions with Public Staff include the following:

a) Remove the initial recommended two-year phase in of base rates.

b) Add Schedule NBR for the Commercial General Service class and the Commercial Demand Service class.

c) Modify the Schedule PPR to reflect the total system avoided costs.

d) Maintain the existing SPP Schedules as established through NCUC Order dated November 22, 2022, for Docket No. E-100, Sub 175, to address any potential other types of renewable energy generation offered to NRLP in the future.

e) Decrease NRLP's Reconnection Charge in recognition of the functionality of NRLP's AMI system.

NRLP has made several changes to proposed tariff wording, as stated in the rebuttal testimony of NRLP witness Miller, in response to Public Staff recommendations. One of those changes relates to the phase-in of the new Commercial Demand rate that was proposed in my direct testimony. After discussion with the Public Staff, NRLP has agreed to eliminate the phase-in proposal due to its effect on other rate classes, and instead have a rate design that would achieve the percentage increases and rate of return index utilizing NRLP's updated revenue requirement, as shown in Halley Rebuttal Exhibit No. 1.

There are three important facts to note about this recommendation.

First, it was not possible to limit the rate impact for each customer class to 2% of the total system increase and attain a rate of return for each customer class at + or – 10% of the total system rate of return. The rate design above is a compromise intended to move the Commercial Demand class more toward their cost of service (i.e., a rate of return index of 1.0) without overly burdening the other classes. It is also important to note that the allocation factors used in the cost of service analysis were developed from NRLP's AMI data from each customer class. This allowed for a much more accurate allocation of costs to each customer class than was attainable in the cost of service analysis performed in NRLP's last rate case.

Second, the numbers in the table above will need to be changed to reflect the revenue requirement and rate of return approved by the Commission. However, the Public Staff and NRLP recommend that application of rate design principles shown in the table above should be similarly applied to the revenue requirement and rate of return ordered by the Commission.

Third and more generally, it is important to state in the Commission's final order and in notices to the public the percentage increase overall and for each rate class in conjunction with the decrease to the PPA factor. A large part of the proposed base rate increase is the reallocation of purchased power costs from the Purchased

Power Adjustment factor to base rates, and thus is not a net increase in the amount that will be billed to customers. The March 20, 2023, Scheduling Order clearly set out the net increase to customers after the PPA reduction, and NRLP encourages the Commission to continue with that approach in its final order.

Q. Please list your revisions based on Appalachian Voices' testimony.

A. In response to Appalachian Voices, NRLP has the following two modifications:

a) NRLP has offered to remove the annual reset of credits for customers on Schedule NBR. We understand that the Public Staff prefers a reset of the energy credits for NBR customers. NRLP does not wish to challenge the position of either Appalachian Voices or the Public Staff on this issue; therefore, we will wait for the Commission's decision without taking a position either way.

b) NRLP had agreed to adjust the amount of renewable energy utilized in its development of Schedule NBR and Schedule PPR to recognize for the portions of the hourly load data missing from its initial analysis. However, this adjustment would have increased the Supplemental Standby Charge (SSC) in the Schedule NBR calculations. NRLP determined it was best to not make this adjustment and cause an increase to SCC.

Q. Are there any other revisions to your original exhibits?

A. Yes. First, NRLP's Purchased Power Adjustment (PPA) was updated after the initial filing of this rate case proceeding. Based on the Order from the Commission dated March 2, 2023, in Docket No. E-34, Sub 56, NRLP's PPA was reduced from \$0.045753 per kWh to \$0.022313 per kWh. All exhibits that utilize the PPA have been updated.

Second, the amount of deferred UBIT taxes has changed since NRLP's initial filing. The most recent amount of UBIT deferral is $931,545. This is down from the original filing amount of $1,027,795.

Q. Which exhibits from your original testimony were updated for this rebuttal?

A. The following is a list of the exhibits submitted with my rebuttal that were modified from those submitted with my original pre-filed testimony:

1. Exhibit REH-3_NRLP Rebuttal – This exhibit contains the updated capital costs that were added to NRLP's Laydown Yard project.
2. Exhibit REH-8_NRLP Rebuttal – This exhibit contains the updated UBIT deferral amount for amortization purposes.
3. Exhibit REH-13_NRLP Rebuttal – This exhibit summarizes all the revenue requirement changes discussed herein.
4. Exhibit REH-14_NRLP Rebuttal – This exhibit contains the updated cost of service analysis.
5. Exhibit REH-16_NRLP Rebuttal – This exhibit contains the update rate design analysis as discussed herein.
6. Exhibit REH-19A(R)_NRLP Rebuttal – This exhibit contains the updated calculations for the Standby Supplemental Charge in Schedule NBR for the residential customer class from the updated cost of service analysis as discussed herein.
7. Exhibit REH-19B_NRLP Rebuttal – This exhibit contains the updated calculations for the avoided costs used in developing the rate for the Schedule PPR.

Q. Are there any new exhibits included with this rebuttal?

A. Yes. The following exhibits were developed based on discussions with the Public Staff:

1. Exhibit REH-19A(G)_NRLP Rebuttal – This exhibit was developed to calculate the Supplemental Standby Charge in Schedule NBR for the commercial general service customer class from the updated cost of service analysis as discussed herein.
2. Exhibit REH-19A(GL)_NRLP Rebuttal – This exhibit was developed to calculate the Supplemental Standby Charge in Schedule NBR for the commercial demand service customer class from the updated cost of service analysis as discussed herein.

III. RESPONSE TO RECOMMENDATIONS OF OTHER PARTIES

A. COST OF CAPITAL

Q. What is the cost of capital recommendation of Public Staff witness Hinton?

A. Mr. Hinton recommends a 50%/50% capital structure, a 3.23% long term debt rate, and an 8.90% rate of return on equity ("ROE"). His recommended overall return (or weighted average cost of capital) is 6.07%.

Q. Please explain any concerns you have with Mr. Hinton's cost of capital recommendation.

A. In my opinion, the overall return of 6.07% would not be sufficient for NRLP. The overall return is more important than the individual components, as it is the overall return that affects earnings. This is especially true where the cost of debt and capital structure are hypothetical or imputed for ratemaking.

Q. Why do earnings matter for a utility that has no investors?

A. As explained in my direct testimony and the rebuttal testimony of NRLP witness Jamison, NRLP finances its capital needs in large part from retained earnings. If the utility were approved for an inadequate overall return, its earnings would be lower. There would be less funds available from retained earnings to finance capital projects, react to unexpected contingencies, and manage cash flow volatility. NRLP does not have the luxury of issuing additional stock to raise more funds in the event of a retained earnings shortfall. The other option is to issue more debt, but whether for NRLP or an investor-owned utility, issuing more debt to make up for inadequate earnings is problematic. As explained by NRLP witness Jamison, there are limits on how much of the utility financing can be accomplished by debt, and it appears from his recommended capital structure that Mr. Hinton agrees that utility financing should not be debt-heavy. Consequently, if the overall return is too low, NRLP will have a shortfall of available cash flow or retained earnings to finance capital projects, and it will either have to issue more debt than reasonable, or the adequacy and reliability of its electric service could be jeopardized.

Q. Do you have concerns about the rate of return on common equity that is recommended by Mr. Hinton?

A. Yes. Of course the ROE is a major factor in the determining the overall rate of return.[1] Mr. Hinton uses three variations on the Discounted Cash Flow ("DCF") model, plus a Risk Premium model, to derive his recommended ROE of 8.90%. I do not have his experience with using the models, but it is evident to me that his recommendation is unreasonably low for several reasons.

First, the 8.90% recommendation of Mr. Hinton is far off the most recent decisions of the Commission. In particular, the Commission approved a 9.80% ROE for both Aqua North Carolina (Docket No. W-218, Sub 573) and Carolina Water Service (Docket No. W-354, Sub 400). The approved overall returns in those cases were 6.885% and 7.22%, respectively. Also, these Aqua North Carolina and Carolina Water Service rate case orders approved multiyear rate plans for the first time, which help the utilities reduce regulatory lag. NRLP does not have that benefit. More generally, I am not aware of the Commission approving less than 9.40% ROE for any major utility in North Carolina in recent years, apart from the non-precedential settlement entered by NRLP in its 2017 rate case. *See* Halley Rebuttal Exhibit No. 2. In short, Mr. Hinton's ROE recommendation for NRLP is out of step with current Commission decisions.

Second, the Hinton Exhibit 1, page 1, shows authorized returns for distribution utilities in other states from January 2022 through March of 2023. This Exhibit shows data from other years as well, but given the regular changes in authorized

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[1] In the present case, both Mr. Hinton and I recommend hypothetical or imputed debt cost rates and capital structure ratios, so there is also judgment in those components of the overall return, unlike cases where the actual embedded cost of debt and actual capital structure are used.

returns, the older data is not so relevant. Hinton Exhibit 1 does not support Mr. Hinton's rate of return recommendation for NRLP. First, his exhibit shows an average ROE for distribution companies of 9.17%, with an upward trend to 9.70% for the most recent order in March 2023. More important is the data on overall return, as debt rates and capital structure ratios also vary among utilities. Based on a data response provided by the Public Staff, the average overall return for distribution companies in the January 2022 – March 2023 timeframe is 6.67%. See Halley Rebuttal Exhibit No. 3. That is 60 basis points higher than the 6.07% recommendation of Mr. Hinton.

Third, Mr. Hinton calculates his recommended ROE by unfairly weighting it toward the DCF results. Hinton Exhibit 8 shows that instead of averaging one combined DCF result with a Risk Premium result, he averaged four results, of which three are from DCF models. His DCF results are much lower than his Risk Premium result, so he chose to weight the lower method three times as much. In the Aqua rate case, Docket No. W-218, Sub 573, Mr. Hinton averaged his three DCF results to reach a single combined DCF number and then averaged that with his Risk Premium result to arrive at his 9.50% ROE recommendation. In other words, he gave equal weight to the Risk Premium and the DCF in the Aqua case, but in the present case he gives DCF three times the weight. In most recent the Carolina Water Service case, W-354, Sub 400, Mr. Hinton likewise gave equal weighting to DCF results and his Risk Premium result, not three times the weighting for the DCF like he does in the present NRLP case. His ROE recommendation in that case was 9.45%. In the last NRLP rate case, Docket No.

E-34, Sub 46, Mr. Hinton gave equal weighting to DCF results and his Risk Premium result, not three times the weighting for the DCF like he does in the present NRLP case. If Mr. Hinton followed the same calculation method for NRLP as he did for his other testimony in utility cases this year, and for the last NRLP rate case, the result would be an average of his DCF results (8.49% + 8.62% + 8.80%)/3 = 8.64% combined with his Risk Premium result and divided by two (8.64% + 9.76%)/2 = 9.20%. In other words, he altered his own methodology to lower his ROE recommendation by 30 basis points in the present case. And even in the recent Aqua and Carolina water rate cases - where Mr. Hinton's methodology produced higher returns than his different approach in the present NRLP case - the Commission approved returns well above Mr. Hinton's recommendations.

Q. **What do you conclude about the cost of capital recommendation from the Public Staff?**

A. The Public Staff's recommendation is far too low. The methodology is skewed unfairly against NRLP. Their result is out of step with recent Commission orders as well as the most recent upward trend as summarized in Mr. Hinton's own exhibits and data response. In my opinion, the 9.6% ROE recommendation in my direct testimony is, if anything, on the low side because a higher ROE is supported by more recent decisions than the ones I relied on.

Q. Please respond to the cost of capital recommendation of Appalachian Voices witness Hoyle.

A. Mr. Hoyle takes an approach to cost of capital that is different from anything I have ever seen filed with this or any other Commission. His approach appears to be driven by the fact that NRLP does not have investors in the traditional sense, and does not issue stock, and therefore assumes a return on *equity* based upon a fixed *debt* rate. However, I believe the Commission should authorize a return for NRLP comparable to that of other North Carolina utilities in the same timeframe, at least for distribution companies. This is, in general, how the Commission has determined and approved NRLP's rate of return in its previous rate cases, acknowledging that the level of financing through retained earnings should be similar to the equity ratios and rates of return approved for other utilities. This traditional approach is consistent with long-standing regulatory rulemaking principles and also recognizes that NRLP finances its capital projects, from both debt and equity resources, as do other utilities.

Q. **What is your response to Mr. Hoyle's recommendation for a DCF analysis?**

A. Mr. Hoyle seems to think a DCF analysis would provide a better basis for determining a risk-adjusted ROE. I disagree. DCF models can be informative, but the models used by financial analysts can produce results that vary widely with the inputs used, and the inputs used appear to vary widely depending on whether the analyst is testifying for the utility or another party. For example, in the recent rate case of Aqua North Carolina (decided in the Commission order issued June 5, 2023, in Docket No. W-218, Sub 573), the utility witness produced in rebuttal his DCF results of 10.22%, and Risk Premium results ranged from 12.06 to 12.31%. Mr. Hinton produced DCF results that averaged 9.03% and Risk Premium results of 9.94%. I can only conclude that the ROE models are at best a loose guide to an appropriate ROE range, and can reflect the outcome desired by the party.

The recommendation of Mr. Hoyle that NRLP should perform a DCF analysis, and then submit a compliance filing for rate of return based on that analysis, is odd. He seems unaware of the wide range of results that are possible from such an analysis – NRLP could submit a result that is much different from what his client seeks. Moreover, he has his own return recommendation of a 6.25% ROE without using a DCF analysis. It is not clear why he recommends that NRLP perform a DCF analysis and submit a compliance filing based on it when he has already concluded that 6.25% is an appropriate ROE.

Q. **What is your response to the 6.25% ROE recommendation of Mr. Hoyle?**

A. Mr. Hoyle's ROE number is derived from municipal bond interest rates. He has substituted a debt cost for an equity cost. This mixing of apples and oranges defeats the whole point of analyst recommendations (including Public Staff witness Hinton) and is contrary to Commission practice and decisions that approve capital structures with a substantial equity component and a calculated return on that equity. Moreover, it is so far outside the range of any ROE that the Commission has approved for any utility in recent memory that it cannot be considered to be representative of a reasonable return on investment to which regulated utilities are entitled an opportunity to earn as a fundamental principle of the regulatory compact where the obligation to provide reliable service is matched with the funding to meet the capital needs.

Q. **Are there other aspects of Mr. Hoyle's cost of capital testimony that concern you?**

A. Yes. He recommends a 78% to 22% equity to debt ratio. This recommendation approximately matches the actual capital structure of NRLP, but ignores the need to use a more balanced imputed capital structure for ratemaking purposes. At a reasonable ROE, instead of the ROE Mr. Hoyle recommends, his capital structure would produce excessive returns for NRLP.

Q. What would be the impact to NRLP of Mr. Hoyle's cost of capital recommendations?

A. The impact would be damaging to NRLP. He recommends an overall return of 5.39%, which is considerably lower than other recent authorized overall returns that I have seen. He states that his recommendation would reduce the revenue requirement for NRLP by $492,711.

Q. Have you made any changes to your original recommendation for cost of capital?

A. No. Although I believe recent events could justify a higher overall return, my recommended overall cost of capital remains at 7.007% as summarized below:

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

B. Net Billing Rider, PPR, and Basic Facilities Charge

Q. What modifications were made to the Net Billing Rider Schedule NBR?

A. During the discovery process, it was determined that the Schedule NBR should be specific to each of the residential, commercial general service and commercial demand service customer classes. The original Schedule NBR was developed using only the residential cost of service. The development of these schedules was consistent with the requirement in N.C.G.S § 62-126.4(b) to avoid cross subsidies.

Q. Is Mr. Barnes approach to valuing solar for use in a Net Billing Rider consistent with the guidelines established in N.C.G.S § 62-126.4(b)?

A. No. Mr. Barnes utilizes theoretical exercises to imply that the value of solar is greater than the actual cost of NRLP's retail rates billed to its customers. He states on Page 28 of his testimony, "According to my analysis, 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."

The value of solar can only be worth the amount of actual costs avoided by NRLP at the time a customer-sited PV generation is operating, given that:

(1) N.C.G.S. § 62-126.4(b) states in part "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";

(2) a cost of service analysis was performed to identify the cost to serve each customer class; and

(3) retail rates were designed based on this cost of service analysis.

All of NRLP's distribution system costs are fixed and would not be avoided if a customer installed and used PV generation. Therefore, it is impossible for the value of solar in a net billing arrangement to be greater than the retail rates.

In my direct testimony I proposed a monthly Standby Supplemental Charge (SSC) of $6.17 per kW of installed solar to recover NRLP's fixed costs that are not avoided from customers who choose to utilize Schedule NBR. Mr. Barnes proposes the elimination of this SSC. His recommendation stems from the "value of solar" methodology discussed above. The NRLP approach is based on a recognition of fixed costs incurred by the utility, recovered in part through volumetric rates, and thus would be under-recovered for customers who reduce usage of NRLP power through solar self-generation. The SSC is designed to recover those fixed costs from the NBR customers who otherwise would avoid them due to their reduced usage of power from NRLP. The goal is to prevent cross subsidies. NRLP believes its approach is consistent with the position of Duke Energy that it is appropriate to recover fixed costs from solar customers to prevent or reduce cross subsidies. This approach has been supported by the Public Staff. It is reflected in the Commission's March 23, 2023, order in Docket No. E-100, Sub 180.

Q. What other option does a customer have for compensation from NRLP for the purchase of energy from solar generation?

A. A customer can choose to utilize NRLP's proposed Schedule PPR. NRLP will purchase energy from any solar PV facility up to a size of 1,000 kW. The development of Schedule PPR followed the same principles used in designing the

Schedule NBR. NRLP's avoided costs were identified and fully credited in Schedule PPR for pass through to participating costs.

Q. Will NRLP continue to offer its existing Small Power Production (SPP) rate schedules?

A. Yes. NRLP will maintain the use of its existing SPP rate schedules for the purchase of any renewable energy generation on NRLP's system that does not meet the eligibility requirements of the NBR or PPR rate schedules.

Q. What is the purpose of a Basic Facilities Charge (BFC)?

A. A BFC is a mechanism used to recover a reasonable amount of a utility company's fixed costs of owning and operating a distribution system.

Q. How is a BFC typically calculated?

A. Utilities in North Carolina have historically used the minimum system method in determining their fixed distribution costs by customer class. In my direct testimony I propose to increase the residential BFC from its current $12.58 per month to $14.50 per month. The BFC is intended to recover a portion of fixed costs that do not vary with the customer's usage. Based on the NRLP cost of service study, the residential fixed cost per month is approximately $36.00. The proposed increase from $12.58 to $14.50 is intended to take a modest step toward sending the appropriate price signal of matching fixed utility costs with a fixed monthly BFC. Mr. Barnes uses the Basic Customer Method to argue that the fixed monthly costs to serve residential customers are below the current BFC, and therefore the BFC should be decreased rather than increased. This is a methodological difference between the parties. I used a modified version of the minimum system method, in which I did not assign any rate base costs that would typically be included in the customer component. Utilizing the traditional minimum system approach would have generated a monthly distribution system cost for a residential customer at a level greater than the $36.00. My approach is more in line with past North Carolina utility regulation than the approach offered by Mr. Barnes. The minimum system method has been used in other electric rate case decisions, it has been supported by the Public Staff in past cases, and it is now required in N.C.G.S. 62-133.16(b) for electric multiyear rate plan cases.

Q. Is Mr. Barnes approach of using only customer related costs appropriate for determining a BFC?

A. No. As explained above, the BFC is designed to recover a reasonable amount of a utility's fixed distribution costs. Lowering the BFC only shifts more fixed costs into the variable energy rate.

C. Public Staff Accounting Adjustments

Q. Which accounting adjustments proposed by the Public Staff do you agree with?

A. NRLP agrees with the following proposed accounting adjustments from Public Staff.

a) Removal of non-utility revenues and expenses.

b) Adjusted materials and supplies included in rate base.

c) Adjusted prepaid expenses included in rate base.

d) Adjusted working capital included in rate base.

e) Adjusted regulatory fee from reduction of revenue requirement.

Q. Which accounting adjustments proposed by the Public Staff do you not agree with?

A. NRLP disagrees with the Public Staff accounting adjustments not listed above; however, for purposes of this rate case I am providing rebuttal on just the following Public Staff adjustments that reduce NRLP's revenue requirement:

1. Reduction of rate of return from 7.007% to 6.07% (addressed in response to testimony of Public Staff witness Hinton, and only incorporated into the revenue requirement by Public Staff Accounting).
2. Disallowance of requested deferrals on the new and old campus substation.
3. Disallowance of requested deferral on previously paid Unrelated Business Income Tax (UBIT).
4. Adjustment to Allowance for Funds Used During Construction (AFUDC).
5. Customer growth and usage adjustments.
6. Adjustment to the test year inflationary factor.
7. Adjustment to depreciation expense.

Each of these items are discussed in more detail below.

Q. Why do you disagree with Public Staff's reduction of rate of return from 7.007% to 6.07%?

A. See my discussion in the Cost of Capital section above and the pre-filed rebuttal testimony of NRLP witness David Jamison.

Q. Why do you disagree with Public Staff's disallowance of requested deferrals on the new and old campus substation costs?

A. The Public Staff's adjustment is inappropriate. The old campus substation was decommissioned and removed from NRLP's books in October 2021. The new campus substation went into service in June 2022.

Regarding the old campus substation, NRLP has requested a three-year amortization of the remaining balance from October 2021. The Public Staff does not oppose a three-year amortization, but calculates it with the net book value balance remaining at July 31, 2023. Their explanation is that depreciation expense for the old campus substation is part of current rates and thus it is proper to reduce the remaining balance amount through the estimated date of new rates that will not include depreciation expense for the old substation. Based on the FERC plant accounting [FERC USOA 10. Additions and Retirements of Plant. B.(2)], a utility must make an adjustment to remove the plant in service and the related accumulated depreciation from the utility's books and stop depreciating the plant once the plant is retired and it is "not used and useful for providing service" to customers. By proposing to carry the net book value of the old campus substation through to July 31, 2023, the Public Staff is incorrectly treating the old campus substation as a regulatory asset instead of a normal plant in service item that is being retired.

Regarding the new campus substation, NRLP has requested a three-year amortization of the depreciation expense and cost of capital from the June 2022 in-service date to the initially estimated August 1, 2023, date of new rates. The Public Staff has adjusted this request in the following ways:

1. In the Public Staff's proposed deferral calculation, they only allowed seven months of depreciation expense and a return on the capital expenditures from

January 1, 2023, through July 31, 2023. The Public Staff stated the rate case application was not filed timely and within the 30-day notice of intent to file a rate case. The main reason for the December rate case filing after the June notice was that NRLP had to clean up the rate case adjustments, revise the rate design, and finalize the models. NRLP ran into some billing data issues related to the allocation factors that took longer to clean up than expected. In addition, some of the capital projects that NRLP was working on took longer than they planned. NRLP would never intentionally hold off on filing a rate case due to the negative earnings impact of staying out any longer than necessary. In sum, NRLP wanted to be sure that its rate filing was complete and in good form with the Commission.

This same issue was addressed in the Dominion North Carolina Power Docket No. E-22, Sub 479, Order Approving General Rate Increase, issued December 22, 2016. On page 73 of that Order the Public Staff contends that the utility's deferral request was inappropriate because the passage of 15 months from the time Bear Garden became commercially operational to the time Dominion submitted its request for deferral accounting was too long. The Commission ruled on Page 77 that "Given the attendant facts and circumstances as outlined above, DNCP's having failed to specifically request formal approval in a timelier manner does not, in this instance, warrant denial of its request." Public Staff's denial of NRLP's depreciation expense and return on capital expenditures from the new campus substation's in service date is inappropriate.

2. The Public Staff recommends the amortization period for this regulatory asset be set at the life of the new substation for 40 years. Use of an amortization period for the remaining useful life of the asset has only been done for assets that were being retired from service on the books of the utility (similar to the old campus substation). The Public Staff cites Docket No. E-7, Sub 1146, with regard to using the amortization period over the remaining useful life for AMR meters. The AMR meters in that docket were being retired from Duke's books and depreciation was stopped. The new Campus Substation is a NEW asset and is not an asset that is being retired from the Company's books.

Cost recovery of capital expenditures is a separate and distinct process from the deferral. NRLP is requesting deferral of certain post in-service costs that reflect the revenue requirement with the new campus substation. The costs to be deferred are the depreciation and the return on the investment for the completed plant in service from the date the assets are placed in service and are used and useful in providing electric service to the date NRLP is authorized to begin recovering the plant in service in rates over the life of the asset. The deferral also includes the financing costs related to the amounts that are unrecovered during the period between the in-service date of the asset and when the "rates" are effective. In Docket No. E-7, Sub 1146, the Commission's Order dated June 22, 2018, also reflects a deferral request and subsequent Commission approval related to DEC's Lee Combined Cycle Facility. The deferral request included post in-service costs of depreciation and the cost of capital similar to the new campus substation. The Order stated that the Company was authorized to establish a regulatory asset for deferral of post in-service costs for the Lee CC, with the post in-service costs to be amortized over a four-year period. The Public Staff's amortization of NRLP's deferred new campus substation post in-service costs over a 40-year period is inappropriate.

Q. Why do you disagree with Public Staff's disallowance of requested deferral on previously paid UBIT?

A. See the pre-filed testimony of NRLP's witnesses David Jamison and Dave Stark.

Q. Why do you disagree with the Public Staff's adjustment to AFUDC?

A. The Public Staff has proposed to calculate all NRLP's AFUDC based on Public Staff's proposed rate of return of 6.07%. Since AFUDC is calculated over a historical period, the appropriate cost of capital to use is NRLP's currently approved rate of return of 6.525%.

Q. Why do you disagree with the Public Staff's customer growth and usage adjustments?

A. The adjustment the Public Staff made to the actual 2021 customer billing data to account for customer growth to 2022 is significantly higher than the actual billing data for 2022. The table below summarizes this difference.

Customer Class	Change in kWh from 2021 to 2022		
	Public Staff's Adjustment	Actual	Variance
Residential	2,651,878	709,667	1,942,211
Commercial	345,929	285,194	60,735
Commercial - Demand	1,788,033	570,841	1,217,192
ASU	3,702,657	3,702,657	-
Lighting	(4,240)	(57,663)	53,423
Total	8,484,258	5,210,696	3,273,562

The revenue adjustment Public Staff made was also based on their adjusted kWh sales. It appears that Public Staff did not account for the increased cost of purchased power from these additional sales. Both of these issues would create an overstatement of net revenues which in turn improperly lowers NRLP's revenue requirement.

Q. Why do you disagree with the Public Staff's adjustment to the test year inflationary factor?

A. As part of the Public Staff's adjustment to recognize additional costs equivalent to those that could be experienced in 2022, Public Staff applied an inflationary factor to expenses that were not modified in other adjustments. NRLP did a similar exercise in the development of its revenue requirements. The inflationary factor utilized by Public Staff was 3.13% as compared to the 6.60% proposed by NRLP, causing a reduction of inflationary adjustments of $208,000. This adjustment seems counter intuitive when considering that the actual operating expenses from 2021 to 2022 increased by 34%. NRLP is not asking to match the actual cost increase for 2022, but simply asking Public Staff not to reduce its inflationary adjustment that is already significantly lower than what actually happened.

Q. Why do you disagree with the Public Staff's adjustment to depreciation expense?

A. The Public Staff did attempt to adjust the depreciation expense and accumulated depreciation to year-end December 31, 2022, levels. However, the Public Staff did not have the correct amounts in the accumulated depreciation adjustments. Public Staff was using an accumulated depreciation amount of $17,721,655 as there beginning balance prior to their proposed adjustments. This amount was taken from Line 208 of Exhibit REH-13, which already accounted for the adjustments Public Staff was proposing. The amount Public Staff should have used as their starting point for adjustments is $17,536,605 as shown on Line 202 of Exhibit REH-13. This error caused an unwarranted reduction in NRLP's revenue requirement.

Q. Is NRLP willing to work with the Public Staff prior to the scheduled hearing to rectify as many of these accounting issues as possible?

A. Yes. NRLP has had several discussions with Public Staff to work through these items and will continue to do so prior to the hearing. We understand the Public Staff may be revising some of its accounting schedules.

Q. DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY?

A. Yes.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-34, SUB 54
DOCKET NO. E-34, SUB 55

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-34, SUB 54

In the Matter of:
Application of Appalachian State University, d/b/a New River Light and Power Company for Adjustment of General Base Rates and Charges Applicable to Electric Service

DOCKET NO. E-34, SUB 55

In the Matter of:
Petition of Appalachian State University d/b/a New River Light and Power for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses

SETTLEMENT TESTIMONY
OF
RANDALL E. HALLEY

July 6, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Randall E. Halley. I am a Managing Principal with Summit Utility Advisors, Inc. ("Summit"). My business address is 7614 Lake Drive, Orlando, Florida 32809.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Applicant, Appalachian State University ("ASU") d/b/a New River Light and Power ("NRLP").

Q. What is the purpose of your settlement testimony?

A. The purpose of my settlement testimony is to provide an overview of, and explain and support, the Agreement and Stipulation of Settlement ("Stipulation") reached with the Public Staff in this proceeding.

II. OVERVIEW OF STIPULATION

Q. Please provide an overview of the settlement Stipulation between the Public Staff and NRLP.

A. The Stipulation, if accepted by the Commission, resolves all issues between the Public Staff and NRLP in these dockets. The Stipulation is the result of a series of discussions between NRLP and the Public Staff beginning the week that NRLP filed its rebuttal testimony. NRLP's first goal was to understand the underlying calculations and bases for the Public Staff's recommended adjustments. Then the settling parties determined that certain reasonable compromises would be mutually acceptable to achieve a non-precedential resolution of contested issues. Other intervenors were not part of these negotiations and have not joined the Stipulation.

Q. Why were other intervenors not part of the negotiations?

A. There was very little time to reach a settlement after NRLP filed its rebuttal position. Multi-party negotiations are generally more time-consuming. Moreover, the policy and methodological issues raised by Appalachian Voices and Ms. LaPlaca are further away from the NRLP positions than were the Public Staff's recommendations, so the chances of reaching a mutually acceptable Stipulation with the other intervenors seemed remote. Of course NRLP would still welcome their support of the Stipulation as a reasonable compromise.

I understand that Appalachian Voices, through their attorneys, did initiate bilateral settlement discussions with the attorneys for NRLP. However, those discussions did not result in a settlement agreement.

Q. What is the status of NRLP rebuttal testimony in light of the Stipulation?

A. Absent an agreement by the other intervenors to join in the Stipulation, the NRLP rebuttal testimony is necessary to address their positions in these dockets. Absent Commission approval of all terms of the Stipulation in a final order approving a partial rate increase, NRLP would also maintain its rebuttal position with regard to any disputed issues between NRLP and the Public Staff. In that event, there would be a need to recognize updates to the accounting schedules since the filing of the rebuttal testimony.

III. MAJOR ELEMENTS OF THE STIPULATION

Q. **Please describe the main elements of the Stipulation.**

A. After reaching greater understanding on the accounting adjustments initially proposed by the Public Staff, the most significant areas of difference were cost of capital, the deferral of old and new campus substation costs, the deferral of UBIT expense for past years, and the customer growth and usage adjustments. The Company and the Public Staff worked together to achieve a revenue requirement that should, with good management and no major unexpected operational or financial setbacks, enable the utility to continue to provide reliable electric service at reasonable rates. The specific adjustments that comprise the Stipulation are reflected in the schedules of the Public Staff's Settlement Exhibit 1. In addition, NRLP had accepted several Public Staff recommendations prior to the Stipulation, as set forth in the rebuttal testimony of NRLP witness Miller and myself.

Q. **Have you prepared a rate design consistent with the principles to which you and the Public Staff previously agreed?**

A. Yes, the resulting rate schedules are attached as Halley Settlement Exhibit No. 1. The cost of service study as updated to reflect the settlement revenue requirement is attached as Exhibit REH-14 - Settlement. As shown in the tables below, the proposed allocation of the settlement revenue requirement among the NRLP rate classes is designed to preserve the class rate of return index figures that NRLP previously agreed to with the Public Staff.

Proposed Settlement

Description	% Base Rate Increase	% Increase with PPA	Rate of Return	Rate of Return Index
NC Retail	22.61%	11.64%	6.165%	1.00
Residential	17.51%	8.24%	7.800%	1.27
Commercial - General	25.63%	15.68%	7.120%	1.15
Commercial - Demand	33.02%	20.45%	3.401%	0.55
ASU	12.90%	0.63%	7.800%	1.27
Lighting	32.85%	21.40%	3.401%	0.55

Public Staff Proposed in Direct Testimony

Description	% Base Rate Increase	% Increase with PPA	Rate of Return	Rate of Return Index
NC Retail	19.62%	8.89%	6.070%	1.00
Residential	14.70%	5.67%	7.680%	1.27
Commercial - General	22.35%	12.64%	7.010%	1.15
Commercial - Demand	29.75%	17.50%	3.350%	0.55
ASU	10.81%	-1.19%	7.680%	1.27
Lighting	29.48%	18.29%	3.350%	0.55

Q. What is the increase in annual revenue requirement resulting from the Stipulation?

A. As shown on the Public Staff's settlement Schedule 1, the NRLP revenue requirement for base rates would increase by $4,288,000. However, some of that increase is from reallocation of purchased power costs from the PPA to base rates. The net increase in annual revenue requirement is $2,207,074. That is the real impact on customers, which is shown in the above columns entitled "% Increase with PPA."

Q. **Which exhibits from your rebuttal testimony were updated for this settlement?**

A. The following is a list of the exhibits submitted with my settlement testimony that were modified from those submitted with my rebuttal testimony:

1. Exhibit REH-14 - Settlement – This exhibit contains the updated cost of service analysis.
2. Exhibit REH-16 - Settlement – This exhibit contains the updated rate design analysis.
3. Exhibit REH-19A(R) - Settlement – This exhibit contains the updated calculations for the Standby Supplemental Charge in Schedule NBR for the residential customer class.
4. Exhibit REH-19A(G) - Settlement – This exhibit contains the updated calculations for the Standby Supplemental Charge in Schedule NBR for the commercial general service customer class.
5. Exhibit REH-19A(GL) - Settlement – This exhibit contains the updated calculations for the Standby Supplemental Charge in Schedule NBR for the commercial demand service customer class.
6. Exhibit REH-19B - Settlement – This exhibit contains the updated calculations for the avoided costs used in developing the rate for the Schedule PPR.

Q. **What is your recommendation to the Commission?**

A. NRLP supports the terms of the Stipulation and its Exhibit as reasonable compromises when taken as a whole. I urge the Commission to approve the Stipulation and establish new rates in accordance with the Stipulation and the NRLP rebuttal testimony that accepts other Public Staff recommendations.

Q. **Does this conclude your settlement testimony?**

A. Yes.

SUMMARY OF REBUTTAL AND SETTLEMENT TESTIMONY OF RANDALL HALLEY

ON BEHALF OF NEW RIVER LIGHT & POWER

DOCKET NO. E-34, SUBS 54 & 55 JULY 10, 2023

My rebuttal testimony first lists revisions that I made to my direct testimony and exhibits based on recommendations of the Public Staff (prior to settlement):

- Removal of non-utility revenues and expenses.
- Adjusted materials and supplies included in rate base.
- Adjusted prepaid expenses included in rate base.
- Adjusted working capital included in rate base.
- Adjusted regulatory fee from reduction of revenue requirement.
- Removed the initial recommended two-year phase in of base rates.
- Added Schedule NBR for the Commercial General Service class and the Commercial Demand Service class.
- Modified the Schedule PPR to reflect the total system avoided costs.
- Maintained the existing SPP Schedules from the November 22, 2022, order in Docket No. E-100, Sub 175, to address any potential renewable generation not eligible for the NBR or PPR rates.
- Decreased NRLP' s Reconnection Charge due to the remote capability of NRLP's AMI system.

In addition, New River was willing to agree to Appalachian Voices' request to remove the annual reset of energy credits for solar customers on the NBR rate; however, the Public Staff prefers a reset so New River is not taking a position on the reset issue.

My rebuttal testimony also updated exhibits for the Purchased Power Adjustment change that was approved after the filing of my direct testimony, and updated the amount of deferred UBIT.

This summary does not address my rebuttal to the Public Staff cost of capital testimony and previously contested Public Staff accounting adjustments, as those matters have been settled.

On cost of capital, my rebuttal notes how Appalachian Voices recommends a 6.25% rate of return on equity <u>on the basis of debt cost rates</u>. That is an extraordinary approach different from anything I have seen filed with this Commission. The New River position is that an equity rate of return comparable to other distribution utilities is appropriate. Because it does not raise capital by issuing stock, New River uses and needs an equity level of earnings to provide enough retained earnings to help finance capital improvements, rather than rely excessively on debt financing.

My rebuttal also takes issue with the Appalachian Voices position that the standby charge for customers on the Net Billing Rider should be eliminated. The approach used to develop the standby charge for New River is based on fixed costs incurred by the utility, recovered in part through volumetric rates, and thus would be under-recovered for customers who reduce usage of New River power through solar self-generation. I calculated a standby charge that allows participating customers to pay their fair share of New River's fixed costs as identified in the New River cost of service study. Appalachian Voices asserts that under its methodology the "value of solar" from customer-generated solar energy is worth more than the New River retail rate and therefore no standby charge is justified. I maintain that fixed distribution costs of New River, as well as the fixed costs that New River incurs to purchase and deliver wholesale power to its system, cannot be avoided and therefore a standby charge to recover those costs is proper to avoid cross-subsidies.

Appalachian Voices also recommends that the Basic Facilities Charge of New River should be decreased rather than increased. This too is based on a difference in methodology between the parties. I rely on a version of the minimum system approach to cost of service; Appalachian Voices relies on a basic customer method. The minimum system method that I rely on is more in line with the approach typically used in North Carolina electric utility regulation. New River's recommendation for a Basic Facilities Charge is meant to move more of the fixed cost recovery into the fixed monthly charge, without making an unduly large change all at once.

Regarding the settlement with the Public Staff, New River has agreed to a reduction in the requested increase of its requested annual revenue requirement as a part of the give and take process in negotiation. Both parties made compromises that do not reflect their respective positions on the merits of specific issues, but achieve a mutually acceptable overall result. The stipulated increase in annual revenue requirement to be recovered in base rates is $4,2888,000. Because part of that increase reflects a reallocation of purchased power costs from the PPA to base rates, the net increase in annual revenue requirement resulting from the stipulation would be $2,207,074. I believe this is a fair and reasonable settlement.

MR. DROOZ: Thank you. Mr. Halley is available for cross-examination.

COMMISSIONER KEMERAIT: Appalachian Voices.

MR. JIMENEZ: Thank you.

CROSS EXAMINATION BY MR. JIMENEZ:

Q Good afternoon. Nick Jimenez for Appalachian Voices. Mr. Halley, you testified in your direct testimony -- this is page 47, lines 11 through 15, but I think you can do it from memory. NRLP is proposing Schedules NBR and IR, Net Billing and Interruptible Rate Schedules?

A Yes.

Q Were you present for Mr. McLawhorn's testimony earlier today?

A Yes.

Q Is it correct to say that under the CPP contract, NRLP incurs greater costs during periods of high demand than during other hours?

A Yes.

Q And those costs are based directly on the per unit, dollar per kilowatt-hour -- rather, dollar per kilowatt demand costs under the CPP contract?

A Yes.

Q So compensating -- customers on Schedule IR, Interruptible Rate customers at an averaged flat volumetric rate for demand reduced over the course of a month would not reflect the actual cost avoided by reducing demand during hours that coincide with a monthly peak, right?

A Are you saying on the IR rate?

Q On IR, using that as a -- yes, on IR.

A Yeah. If the customers on the IR Rider do not curtail during that one peak hour, they do not get a rate reduction.

Q If they did curtail and you compensated them, NRLP compensated them at a flat -- averaged flat volumetric rate that would not accurately reflect the costs that those customers avoid, right?

A I'm sorry, repeat that.

Q I'm trying to skip through here, so I'm --

A Understood.

Q -- lacking some of the background that I intended to cover. On Schedule IR, $14.26 per kilowatt during -- for reduction and demand during coincident peak, right?

A Yes.

Q If instead that were -- they were compensated at an averaged flat volumetric rate, say the coincident peak is two hours and they were compensated at an average flat volumetric rate, the retail rate during that period, that wouldn't reflect the costs that they avoid, that they allow New River to avoid, would it?

A I'm sorry, I'm still not following the question.

Q I might need to back up.

A Can I rephrase what I think you said?

Q Sure.

A Are you asking me that if a customer on the IR rate is -- reduces their peak in that one hour, that they would get that reduction in the kW charge, and then are you saying -- does that effect their whole cost of energy for the month?

Q I'm trying to relate the cost of ener -- close. I'm trying to relate the benefit that the customer receives on Schedule -- on proposed Schedule IR from reducing during coincident peak to an averaged flat volumetric rate for the cost of energy during that coincident peak period, not over the whole month.

A Well, if they're on Schedule IR, the customer's already going to be on Schedule GL, which is the large general service demand rate, so they're already paying an energy charge that's based on the cost of service for that demand rate. The only reduction they get from Schedule IR is if they are successful in reducing their peak in that one hour that meets the -- that matches the CPP hour. That's the only time they would get a credit. If they missed that peak, they get no credit.

Q And that credit's based on the cost that they're reducing demand allows NRLP to avoid under its contract with CPP?

A That is correct, yes.

Q Okay. Were you present for Witness Miller's testimony on cross-examination earlier today?

A Yes.

Q Do you have anything to add or correct or disagree with respect to ASU's prior and current net metering or net billing practices?

A Is there a specific point you're wanting to clarify or --

Q Well, we can go back to the exhibits but I examined Mr. Miller on a number of exhibits that reflected an exchange that you and he had concerning potential compensation for an ASU

solar facility that could be developed. I just wanted to get your take on his testimony, whether you agreed, whether you had anything to add.
A I mean, I don't remember it word for word but I remember it being fairly accurate to what transpired, yes.
Q Thank you. Now, I want to see if I understand how you accounted for the value of customer-sited -- that customer-sited solar provides to the system or as you put it, the costs that are offset by generation of the customers' premises. You said customer-sited PV did offset a portion of NRLP's costs from CPP demand charges, CPP energy charges, DEC transmission charges and BREMCO distribution charges. This is at page 48 lines 9 through 11. Is that right?
A In direct? In my direct testimony?
Q This is direct, that's right.
A And I'm sorry, what page was that again?
Q 48.
A 40?
Q 48.
A 48, I'm sorry. Okay, I see that.

Q And you found the PV facilities were generating approximately 29 percent of their maximum output during the times of BREMCO and DEC coincident peak hours, and approximately 26 percent during CPP's coincident peak hours. That's also on page 48 lines 11 through 14, correct?
A Correct.
Q The amount that the customer-sited PV reduces NRLP's demand-related costs should be passed on to the customer owning the generation. Wouldn't you agree?
A I'm sorry, say that again?
Q The amount that customer-sighted PV reduces NRLP's demand-related costs should be passed on to the customer owning the generation, right?
A In relation to how the residential class rate was designed in that proportion, because the way that I -- the way that the -- the way we set up the NBR is we took a look at, our cost of service developed the rates. The rates recover the actual cost of service that NRLP receives to recover those rates. We looked at what was the contribution of that solar -- those solar facilities, actually how does that reduce the

billing determinants that the residential customers would be paying to New River, basically, how much energy that reduce in receiving -- that New River would receive from the customers buying the power. We looked at that lost revenue piece as the avoided cost that New River needs to recover from its fixed cost so that's how we utilized the demand component.

Q I think I'll come to that later. So, well, coming back to those, the percentages that we just discussed, the contributions to peak, you discounted the value provided by solar according to how much you found that it contributed to avoiding coincident peak, right?

A I wouldn't say I discounted the solar. I accounted for how much it actually reduced the expense that was built into the residential retail rate.

Q Okay. You testified that -- this is page 48 lines 2 through 4: *Since NRLP's distribution system costs are fixed in nature, these PV generation facilities do not reduce any of NRLP's distribution costs*, correct?

A Correct.

Q So to be perfectly clear, it's NRLP's contention that there is absolutely no portion of its distribution infrastructure investments that would ever vary with sales?
A That is correct, based on the rate design we have right now.
Q And no portion of New River's distribution costs would ever vary with sales or usage?
A Correct.
Q But practically speaking, NRLP's distribution system will change over time, will it not?
A I would assume so. They are doing investments in the system itself.
Q It could expand?
A If they add customers, potentially, yes.
Q So there must be some future costs associated with NRLP's distribution system.
A Yeah, but when we're designing rates, we're not looking at future costs. We're looking at the actual costs that were incurred in the test year plus adjustments for known and measurable changes, so that's how the retail rates were designed. So solar is only going to reduce the amount of revenues New River recovers for those

fixed costs. So that is where we came up with the charge that we have per kW for the solar installed to make sure those fixed costs are recovered based on the revenues we designed to recover those fixed costs from New River's customers.

Q And your solar value used an averaged flat volumetric rate as the rate at which system value accrues, right?

A The solar value in my Exhibit 19A, is that what you're talking about?

Q Yeah or 19A or -- yeah.

A We took -- again, it's the average cost of the rate that we have to recollect the actual cost for New River in those rates, so that is -- that's the actual rate that we're using as avoided cost, if you will, for the -- not the avoided cost, I take that back. The fixed costs or the average costs of the residential rate that we would, that New River would not have received if all that solar was installed behind the meters. That's the rate that we're using to make sure New River is made whole on the fixed cost.

Q Okay. I think you're getting to this -- you

testified that the value of solar can only be worth the amount of actual costs avoided by NRLP at the time a customer-sited PV generation is operating. This is rebuttal, page 16, lines 13 to 14. Is that right?
A 13 through 14?
Q Yes.
A That is correct.
Q So I think we agree with that. But from that, you conclude that the value of solar cannot exceed the retail rate. Is that right?
A That is correct.
Q And in your testimony, this is rebuttal testimony, you offer a, sort of, series of premises supporting that conclusion, correct? This is page 16. They're numbered, premises here, lines 15 through 20, and then a conclusion on page 17 lines 1 through 3. You recognize all of that?
A Yes.
Q And the conclusion is all of NRLP's distribution costs are fixed and would not be avoided if a customer installed a new PV generation. Therefore, it is impossible for the value of

solar and net billing arrangement to be greater than the retail rates, correct?
A Correct.
Q I want to see if I understand how your premises here lead you to that conclusion. So going back to Schedule IR as an analogy, okay, you recall how we agreed that NRLP incurs greater costs during periods of high demand than at other hours?
A They incur greater costs at their CPP, so yes, that would be a higher demand.
Q Yeah. Okay. And a customer on Schedule IR would be paid $14.26 per kilowatt of load reduced at the time of coincident peak?
A Yes, if they're able to reduce during that coincident peak, yes.
Q If they do it. And that's based on NRLP's costs under its contract with CPP?
A Correct.
Q So isn't it true that anything that reduces demand equivalently would be worth $14.26 per kilowatt during coincident peak?
A Well, in essence, we did -- we did correct that in Exhibit 19. Again, the way we did Exhibit 19,

which is where we set up the Net Billing Rider, the cost of service allocates all fixed costs to each customer class, and we're going to talk specifically to the Carolina Power Partners CP demand, since that's what -- the question, what I've been asked here. We know exactly how much each of the residential customers contribute to that peak. That allocated demand was at that -- demand cost was allocated to the residential class, and then rates were designed to collect that demand.

So, again, the rates we have for the residential class collect all the fixed costs and variable costs that are in the cost of service. Since we only have a basic facilities charge of -- that we're proposing a fourteen fifty, a majority of those costs are -- have to be rolled into the energy rate, so that energy rate that we have ensures that all the rest of those fixed costs are collected. So New River designs a rate based on what the projected energy is for each of those residential customers, and that's how we collect those fixed costs.

If we allow solar to be placed

behind the meter, that total energy is reduced, therefore, reducing the revenues that New River would collect and not collecting all the fixed costs that would be included in those costs. So, in effect, we are giving solar the same cost that was being allocated to that residential class.

Q So if I under -- I think -- I'm trying to pin down the, sort of, difference of opinion here. If I understand what you just said, the residential retail rate includes fixed costs and effectively compensating solar at the residential retail rate through net billing, avoids those fixed costs. What I don't understand is how that's a limit on the value that solar provides to the system and to NRLP during times of coincident peak. Why would solar -- why would reducing demand in some way be worth $14.26, but solar, reducing NRLP's demand from CPP, the same amount, could only be paid the average volumetric rate?

A Well, as you pointed out in my testimony, we're saying that on average, the solar only hits that peak roughly 26 percent of the time, so there's no way they're going to get the full fourteen point two six cents for the kilowatt. That's why I'm saying the way we've allocated it in the rate for the residential customer, that rate has to be collected from the residential class. And we do allow a reduction in the BREMCO demand charge, we do allow a reduction in the DEC transmission charge, and we do allow a reduction in the Carolina Power Partners demand charge based on those percentages at the time that the solar is operating when those CP peaks happen, so they are being compensated fairly for how the costs are incurred for the residential class.

Q So, I'm hearing one of the -- I'll just call them discounts because I'm a lawyer and I don't know the right terms necessarily. One discount is the percentage that solar is actually generating during the peak time, and the other one is what you compensate solar for providing that value, at that time. So I think we agree, if you were here for Mr. Barnes' testimony, that the, sort of, percentage reduction, percentage that solar's actually contributing to reducing peak, makes sense, but shouldn't you multiply that percentage by the actual cost avoided, whether it's $14.26

times the 26 percent, say, rather than using the flat volumetric rate?

A Again, we are addressing the value of solar to the residential class based on the amount of energy it would reduce. The residential class, again, has a retail rate that is collecting fixed costs in the energy rate, so, you know, you have to -- and to ensure that New River is recovering all their costs, the only thing you can look at that's fair is to allow -- reduce the demand, I mean, reduce the energy that New River would collect in that retail rate design, determine how much revenue is not being collected, and then identify what's a fixed charge. You need to charge those individual customers who are causing that revenue not to be collected.

Q Okay. I'm going to try one more because I don't want to take everyone's time. I feel like I'm starting to beat a dead horse here. But you know, what? I will not land that last blow on the horse's body, corpse. You testified that you used a modified version of the minimum system method, right? This is rebuttal, page 19, line 1.

A Yes, I did say that.

Q And you testified that the minimum system method has been used in the past in North Carolina?

A Yes, I did say that.

Q But as far as you know, the minimum system method with your modifications has never been used before, has it?

A You mean, by other utilities?

Q By anyone.

A That, I don't know.

MR. JIMENEZ: Pass the mic.

CROSS EXAMINATION BY MR. MAGARIRA:

Q Good afternoon, Mr. Halley. Munashe Magarira, co-counsel for Appalachian Voices. I have some questions with respect to cost of capital. To start off, New River originally proposed a rate of return of 7.007 percent?

A That's correct.

Q And this rate of return was based on an ROE, Return on Equity of 9.6 percent, cost of debt of 4.2 percent, and a 52 percent equity to 48 percent long-term debt capital structure?

A Correct.

Q In the Stipulation, New River and Public Staff agreed to an overall -- sorry, rate of return, I should say, of 6.165 percent?

A Yes, correct.

Q And this rate of return has a lower ROE, lower cost of debt, and has a 50/50 cap structure, hypothetical?

A Correct.

Q Okay. Obviously, recognizing the parties' stipulated positions, would you, nonetheless, agree that, you know, New River's original proposal, at least from your perspective, was reasonable, and is reasonable?

A My original proposal? Yes, I would say it was reasonable.

Q Okay, shifting gears slightly. In your testimony, I believe this would be, kind of, disbursed throughout it, you mentioned that there are a couple of factors that, sort of, drove the rate increase, and those include, I think, five specific capital infrastructure investments that you cite or reference. Is that right?

A Correct, yes.

Q Okay. Again, just in the interest of moving things along, obviously, you know, subject to check, would you agree that four out of those five capital infrastructure investments have, I guess, service lives that would be greater than 30 years? And for reference, this would be the warehouse laydown yard, the undergrounding of lines -- basically it's all the investments except for the SCADA investments.

A Got you. Yeah. I mean, I'm not a depreciation expert but that would sound reasonable.

Q And I'm just going off of what you put in your testimony.

A Yeah.

Q Yeah. Okay. New River, obviously, is an operating armor division of Appalachian State, correct?

A Correct.

Q Meaning, that it does not have shareholders?

A Not that I'm aware of.

Q Okay. So New River's capital financing needs are satisfied through debt financing and its retained earnings?

A That is correct.

Q So the two utilities that you cite in your testimony as peers and also the reference for

your proposed return on equity, excuse me, are Piedmont and Public Service. Is that right?
A That's correct.
Q And both of them are gas distribution utilities?
A Correct.
Q Would you agree, as a general proposition, that gas utilities have a different risk profile than electric utilities?
A Not significantly. That's why I use them as an example.
Q Okay. Did you conduct any analysis specifically comparing the risk profiles?
A I don't know if I did or not. Do you have a reference to it, by any chance?
Q No, no, I'm asking you did you conduct any additional specific analysis.
A I don't recall if I did or not.
Q Okay. And Piedmont and Public Service are not state-run utilities?
A That is correct.
Q And their parent company is Duke Energy and Dominion. Those are publicly-traded companies?
A Correct.
Q Meaning, that their parent companies, at least,

have shareholders who, I guess, expect to be invest -- sorry, expect to be compensated, I should say?

A Correct.

Q Okay. So to be clear, based on, sort of, what you testified on the stand and in your prefiled testimony, the basis for your comparison between New River, Piedmont, and Public Service is that they are distribution-only utilities that are regulated by the Commission?

A That would be correct.

Q So still on the same, I guess, topic or subject, obviously, this is a basic point but Appalachian State, Piedmont, and Public Service, they have credit ratings, right?

A Yes.

Q Okay. And when credit rating agencies rate borrowers or they rate their debt issuances, they're measuring the ability of the borrower to honor their debt obligations?

A That is my understanding, yes.

Q Which depends in part on the borrower's risk profile?

A Partly, yes.

Q Okay. Also depends in part on, sort of, their financial strength, right?
A Partly.
Q Okay. Again, trying to move things along so obviously, feel free to answer this to your comfort level. Would it surprise you that Appalachian State has a higher credit rating than either Piedmont or Public Service?
A I'm not aware of that.
Q Okay. Okay. So in addition, you cite a Value Line Survey of earned -- Returns on Equity, and I might have gotten this count wrong, of 34 electric utilities. Do you recall that? This is from your direct testimony.
A What page is that on?
Q So if we're going by a line number, just give me one second. Yeah. Sorry. This is going to be page 28 starting on line 13 but it's Table 4. It's your direct testimony.
A Got you. Okay, I see it. And what was the question? I'm sorry.
Q I'm just saying that you cited a Value Line Survey of these utilities.
A Yes, yes.

Q That's all I'm confirming.
A Yes.
Q Okay. So these utilities include both distribution only and vertically-integrated utilities?
A Correct.
Q So just to recap, New River, which has no equity shareholders, in calculating its Return on Equity, it took the average of the allowed Returns on Equity for two gas utilities, took the, I guess, average of these earned returns for these utilities that include both distribution and vertically-integrated utilities, and then also, sort of, looked at earned Returns on Equity of utilities to determine ultimately its Return on Equity?
A That was my approach, yes.
Q Okay. Right. Moving on, New River's originally proposed cost of debt was 4.2 percent?
A That sounds right. Hang on a second.
Q And if you want a --
A Where are you seeing this?
Q So it's actually -- so it's line 29 -- sorry. I needed to speak into the mic. It's line 29 on

page 2.
A That is correct.
Q Okay. And so this proposed cost of debt was calculated by averaging the approved long-term costs of debt for Public Service and Piedmont, specifically the cost of debt that were allowed in those two cases?
A Yes, that is correct. I did that because we were looking at imputed 50/50 capital structure instead of the 50 of what, 78/20 or whatever the original structure was, so, but, yes, that is what we did.
Q Okay. You would agree, just as a general matter, that when you're calculating costs of debt for rate-making purposes, you should be referring to the utility's-own embedded cost of debt?
A Not necessarily in the rate design perspective, no.
Q Okay. You testified -- and this is page 30 of your direct testimony. I'm referring here to Table 5, that New River's actual cost of debt at the time the Application was filed was 2.3 percent?
A That is correct.

Q Okay. All right. So on page 31 of your direct testimony, beginning on line 12, you propose a 52 percent equity to 48 percent long-term debt capital structure?
A Yes.
Q And, ultimately, this is a hypothetical capital structure?
A Yes. For rate design purposes, yes.
Q As you'd admit on page 30 of your direct testimony, this is beginning at line 17, the Commission has actually approved New River's actual capital structure in past proceedings?
A That is correct.
Q Okay. And in one of those proceedings, the approved capital structure was 6.42 percent of long-term debt to 93.58 equity?
A That is correct.
Q Okay. Just a couple more questions. It should only be maybe two or three more minutes, tops. And this is -- we're moving on to your rebuttal testimony. So Public Staff and App Voices, obviously, have both contested cost of capital?
A I'm sorry, say that again?
Q The Public Staff and App Voices have both

contested cost of capital in this proceeding?
A Correct.
Q Again, just to eliminate the need for having exhibits, do you recall providing, in response to discovery, that the, I guess, the reason why App -- sorry, the reason why New River did not submit, I guess, a DCF analysis was in part to basically save costs to ratepayers. Do you recall that as a discovery response?
A Yes. We did not do that, wanted to save costs, but we also knew that the DCF Model, in my opinion, does fluctuate drastically given inputs that you've put into the DCF Model.
Q Do you also recall saying that you did not -- and this is, again, in response to discovery request from App Voices, do you also recall saying that another reason why you did not conduct the DCF analysis was because you have no experience working with the DCF analysis?
A That is correct.
Q Mr. Halley, you were a cost of capital witness in the E-4, Sub 46 proceeding. Is that right?
A Was that the last one for New River?
Q Yes. It was the one that was filed, I think in

2017.

A 2017? That's correct.

Q Yeah, that sounds right. Were you here or do you recall some of my, I guess, conversation with Witness Hinton with respect to how you calculated a DCF analysis?

A I remember the conversation you had with Hinton, yes.

Q Okay.

MR. MAGARIRA: Commissioner Kemerait, may I approach?

COMMISSIONER KEMERAIT: Yes, you may.

(Exhibits passed out)

COMMISSIONER KEMERAIT: We'll go ahead and mark this exhibit as Appalachian Voices Cross Examination Halley Exhibit 1.

(WHEREUPON, Appalachian Voices Cross Examination Halley Exhibit 1 is marked for identification.)

BY MR. MAGARIRA:

Q And do you recognize this to be your testimony that you filed in that proceeding?

A Yes.

Q Okay. Can I have you turn to page 6 of your

testimony starting on line 152?
A Yep.
Q You see there that you discuss the DCF Model or analysis, right?
A Yes.
Q Can you turn to page 7, so the next page, lines 180 through 183?
A Yes.
Q And, again, I know I mentioned this more broadly, but do you recall my conversation with Mr. Hinton with respect to -- in solving for the cost of capital, you take the dividend yield and you add the expected growth rates of dividends to that yield?
A I remember you talking about it. Whether I followed it or not, no.
Q Okay. Well, subject to check, he -- actually, let me rephrase that. During that conversation, Mr. Hinton said that it would be improper to add an expected growth rate to the denominator, and subject to check.
A Subject to check.
Q Okay. And yet, if you look here, it appears that there is an expected growth rate that has been

added to the denominator?
A In that formula, yes.
MR. MAGARIRA: Okay. No further questions.
MR. CREECH: No questions.
COMMISSIONER KEMERAIT: No questions from the Public Staff. Redirect from New River?
REDIRECT EXAMINATION BY MR. DROOZ:
Q You were asked some questions about how the IR, the Interruptible Rate, was calculated in comparison to the NBR rate. At least with respect to residential customers, does the NBR rate have a demand charge?
A The NBR rate?
Q The NBR rate.
A It does not, no. The residential customer does not have a demand charge.
Q It's strictly a volumetric charge?
A That is correct.
Q And does the Interruptible Rate for the GL customers have, have a demand charge?
A Yes.
Q Okay. You were asked some questions about essentially the volumetric -- the use of volumetric rate for your calculations here

related to the standby charge, and Witness Barnes had claimed that you have a math error. Do you agree with that?

A No. It was more of a methodi -- a method -- a difference of opinion than a math error. There was no math error in my calculations.

MR. DROOZ: That's all my questions.

COMMISSIONER KEMERAIT: I just have a couple of quick questions.

EXAMINATION BY COMMISSIONER KEMERAIT:

Q Can you provide a little bit more detail about the difference of opinion of -- you said that it's not a math error but you have a difference of opinion. And just provide --

A Sure.

Q -- some -- succinctly, I would appreciate it, to explain why you think that your methodology is correct as opposed to Witness Barnes.

A Yes, ma'am, I will. At a high level, again, we did a cost of service to identify the cost to provide service to the residential class. Then we take those costs and design rates to recover those costs, and then that's without solar included.

If you take those rates that we designed, based on the actual sales that we're projecting, the kilowatt-hour sales that we have for those residential class, you will recover all those costs that we have allocated to that class. If you introduce solar behind the meter, that's going to reduce the amount of energy that the residential customers purchase from New River. In essence, not collecting all the costs, so those costs would have to be collected somewhere else in the next break study, if you will. So that's the -- that's how I did my calculations. He went -- he -- pardon me.

Witness Barnes took the approach of how much is the solar reducing the distribution cost individually outside of the rate design piece, and I differ with him completely. There is no reduction in distribution cost. He's also taking those individual -- the models that he ran on his solar production model, the PVwatts Solar Production Model to identify what was the -- what would have the demand have been during those peak hours. He specifically applied those rates to those specific hours that he identified that the solar would be running and giving it a value from that perspective.

So the difference is he is approaching it from how is that -- how is the solar impacting those individual -- what would the individual cost be impacted just by the solar itself. I'm taking a look at it from the standpoint how does the impact of the solar impact the recovery of revenue from the residential customers based on the rate design that we did, based on the cost of service. So in a nutshell, is that helpful?

Q Yes. Thank you very much. And then just two other very quick questions. One is we've heard a lot of testimony about the SSC, whether it should be based -- the calculation be based on the System Design Capacity or the Name Plate Capacity. Do you have a position about -- Public Staff seemed to agree that System Design Capacity might be appropriate, and Appalachian Voices strongly believes that. Do you have a position that System Design Capacity might be a better way for the calculation?

A Absolutely. The intent of the calculations that we did was based on the actual maximum output of the AC to New River's system. So if AC Name Plate Capacity is the wrong terminology to use for that, absolutely. We designed it based on the actual AC output of the system being delivered to New River. So whatever that needs to be called, we are totally open to change the reference to it.

Q Okay. And then this is -- last question, this comes from Commission Staff, and it relates to the basic facilities charge. And in your direct testimony, you talk about the increases of the basic facilities charges for various customer classes, and for the residential customer class -- this is pages 44 to 47 but I don't know if you necessarily need to turn there -- you state that the proposed basic facilities charge of $14.50 is well below the residential monthly fixed cost of $36. Can you explain how you arrived at the amount of $14.50?

A Absolutely. Knowing full well you're never going to get the minimum, you're not going to get $36. We looked at what other utilities were charging, what other utilities were being given approval for in current rate proceedings, and we felt the $14.50 was in line with what was being approved by this Commission.

COMMISSIONER KEMERAIT: Okay. Thank you. Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. Halley, I'll try to be -- collapse a few things. I think Mr. McLawhorn kind of said it best, is that the difficulty we're having with some of the disputes about the design of the SSC here is that one group is advocating that you consider the value based upon time-differentiated cost analysis, and as Mr. McLawhorn says it, you don't have a rate structure that allows you to accommodate that in your cost recovery. So here's the question. There was some discussion that the Company is considering bringing forward, time-differentiated rates. Where does that stand, what's the timetable, and when do you expect New River would bring forward a time-differentiated rate structure? That would then enable us to consider your ability to recover through your rates based upon a cost analysis that's also time-differentiated. Where do you stand?

A I believe that was in Witness Miller's testimony.
Q Right.
A Like, I think it was roughly two years is what was listed in the testimony. And the reason for the two years is, as he explained, they're still working to make -- we just got the -- they got the software updated in February, so we need to get a good year or so of data to ensure we agree that that system is collecting the data correctly before we even attempt to try to design a time-of-use rate.
Q Okay. So we've got testimony from Mr. Miller that the data collection problems have been resolved as of about, well, a year ago now. February of '22, if I heard him right. Maybe I heard him wrong, but the record will be what it is.
A Okay.
Q February of '22 or whatever.
A I understand.
Q But going forward, we'll be able to capture accurate solar production data and maybe another two years to develop some understanding of where you might come in with time-of-use rates. So

would it not be appropriate, then, to revisit how the SSC was calculated at the point in time when the Company might be ready to come forward with the time-of-use rates?

A I think it might be reasonable because at that point, you know, to your point, Commissioner, we'll have the hourly data. Once we come forward, we're comfortable with the data we have. I have not personally looked at the data we've been collecting to tell you I'm comfortable with it yet. But once we're comfortable, that would be -- I don't see why that would be a bad opportunity to take a look at this again.

Q Okay. It may not be as important now as it was earlier in the hearing, but just to close the loop so it's not left hanging out there, what is the revision that was made in Miller Rebuttal Exhibit Number 1? How did it get revised? How was the data corrected?

A I need to see that exhibit. I'm so sorry.

Q He's referred the question. You're my third try.

A I know. I will answer your question, I promise.

Q Okay. Thank you, sir.

MR. DROOZ: And that ties to the testimony on Miller page 6?

COMMISSIONER CLODFELTER: Yes, it does.

MR. DROOZ: Okay, thanks.

COMMISSIONER CLODFELTER: Well, it does, and it also ties to Mr. Halley's rebuttal exhibit -- testimony because he testifies on page 9 that there was no correction made, and I'm just totally lost. I just need to get the record clear.

A Commissioner, Exhibit 1 is the rate schedules that we submitted in Miller Exhibit 1. Is that what you're referring to?

Q Well, let's look at Miller Rebuttal Exhibit Number 1.

A Yes, sir, that's what I'm looking at. And what I have --

Q And he says that corrects -- that exhibit corrects for the missing hourly solar data. How does it do that?

A Okay. So the numbers that were changed in Miller's Exhibit 1 for the NBR was the actual rate calculations of what the SSC would be for the residential class, for the commercial class, and the commercial demand class. And those were updated based on, one, that the updated and the revenue requirement and the -- well, this is rebuttal, so this wouldn't include settlement, but this was just updated revenue requirements that we had in getting to the rates that we proposed. But I don't see reference to the hourly load data in this exhibit, and I apologize.

Q Well, I'm going to read it for the third time. This is what Mr. Miller testifies, on page 6 of his rebuttal, 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 is shown in Miller exhibit --

A You know, I'm reading it. I see that.

Q Yeah. And, so, what was the adjustment made to accommodate the missing data? I just want to know how it was changed.

A Yeah.

Q What's the calculation you made? What did you do?

A Well, I can tell you what we did with the hourly data. Would that be helpful?

Q That's the question.
A Okay. I'm having trouble tying Mr. Miller's Exhibit 1 to that, but let me answer.
Q All I have is the paper in front of me.
A I understand, totally understand. In the hourly load data we had, we had for specific CP demands, because we had the CP demand for BREMCO, the CP demand for DEC transmission, and the CP demand for Carolina Power Partners. We pulled the actual hourly load data from those 15 customers and that was the load that we were trying to accommodate for. In each of those load profile -- in each of those data points, we were missing about, I guess about 17 -- excuse me, about 17 percent is what I recall. And in those specific hours that were missing, we went and looked at the individual -- each individual customer's load data, and we looked at when was the first -- when was the last data that was saved, when was the first data saved, and then the last data saved, how many hours were in between those two times, because what's saved is the cumulative amount.
As an example, if we had -- if the

cumulative amount was 100 and there was 10 hours in between that, there would -- 10 kW would be -- have been filled in for that missing hour. Is it perfect? No. But we, at least, wanted to go back and make sure we had some data points that were reasonable given the missing data we had, but were reasonable based on those load shapes that we did have.

Q You took the total that you did have and allocated it back through the missing hours?

A That is correct.

Q Thank you, sir. It's a simple question --

A Okay.

Q -- and I just finally got a confirmation of what you did, because, again, your rebuttal testimony says you didn't do that correction. You say that on page 9 of your rebuttal testimony, and I just needed to get the confusion cleared up.

A Okay.

Q Now, another confusion that you just created for me with your answer to Commissioner Kemerait. In terms of the concern about unrecovered fixed costs, that's what you're calculating the SSC to compensate for?

A Correct.
Q Is otherwise unrecovered fixed cost. What you really are concerned about is not the amount of eenergy that the net metering customer is exporting to the grid, you're concerned about the amount that they're not taking from the grid, correct?
A That's correct.
Q And the inverter has nothing to do with that, does it?
A Yeah. That's where I lose -- that's not my area of expertise. Again, the intent was to -- the data that we took is the actual data -- the actual load that was put from these -- actual loads into New River's system. So we are taking -- whatever that needs to be called. I don't know if it's from the inverter amount or it's the Name Plate Capacity amount but we took what was actually delivered to the system at peak times. As an example, if one of the customers, the maximum that they put on in that one-year period, the maximum was a 9.6 kW, we assumed that number is the maximum amount that we would be applying the SSC to.

Q Thank you, sir. It just -- the light bulb just went off. You did that because what you're looking at right now is two meter data. You're looking at the data that's coming from the current SPP's rate structure, right, buy all/sell all --
A Uhm-uhm.
Q -- where there's two meters. You're looking at the second meter?
A Yes, sir.
Q Ah. That clears up the confusion completely.
A Okay.
Q Would you, though agree, that in terms of the principal of recovering the cost that New River needs to recover, that what really matters is how much --
A I can't -- I'm sorry. I couldn't hear you.
Q -- is how much the consumer is not taking from the grid. That's what really matters.
A That is correct. That's how we --
Q So if we go to a single meter system, a single meter system, the inverter controls the capacity to inject into the grid, but what really matters in terms of how much the customer doesn't take

from the grid is the maximum power of the solar panel itself, right?

A Correct.

Q I think we're finally clear. Thank you, sir.

A You're welcome.

COMMISSIONER KEMERAIT: Okay. Questions on Commission questions?

MR. CREECH: No questions.

COMMISSIONER KEMERAIT: Appalachian Voices?

MR. MARGARIRA: No questions from Appalachian Voices.

COMMISSIONER KEMERAIT: New River?

MR. DROOZ: No questions.

COMMISSIONER KEMERAIT: So I'll hear motions from New River and from Appalachian Voices.

MR. DROOZ: We would ask that the exhibits of Mr. Halley be admitted into evidence, his direct, and rebuttal, and settlement exhibits, and his amended or revised exhibits.

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

(WHEREUPON, Exhibits REH-1 through REH-24; Exhibits REH-3-Version 2, REH-13-Version 2; Halley Rebuttal Exhibits 1-3, Exhibits REH-3, REH-8, REH-13,REH-14, REH-16-NRLP Rebuttal, and Exhibits REH-19A (G),REH-19A(GL), REH-19A(R), and REH-19B; Halley Settlement Exhibit 1, Exhibits REH-14-Settlement, REH-16, REH-19A(R), REH-19A(G), REH-19A(GL), and REH-19B-Settlement are received into evidence.)

MR. MAGARIRA: At this time, App Voices would move to enter into evidence Appalachian Voices' Cross-Examination Halley Exhibit 1.

COMMISSIONER KEMERAIT: And also seeing that there is no objection, your motion is allowed.

(WHEREUPON, Appalachian Voices Cross-Examination Halley Exhibit 1 is received into evidence.)

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

THE WITNESS: You're welcome. Thank you.

COMMISSIONER KEMERAIT: So it's almost five o'clock. We have one more witness, Witness Jamison, I believe.

MR. STYERS: Correct.

COMMISSIONER KEMERAIT: And from the information that I have, I said we had to finish by five o'clock, but I have got an agreement from the Court Reporter and from the Commission that we really have a drop dead time of 5:30, but the cross-examination estimate was -- is 20 minutes.

MR. MAGARIRA: Commissioner Kemerait, if I may, I'll try and keep my cross-examination questions really, really brief. I plan to cut some questions, so I think it'll probably be less than the 15 or 20 minutes that was allotted, so...

COMMISSIONER KEMERAIT: So then we'll proceed and we will absolutely be stopping at 5:30, but I have every belief that we'll have this hearing concluded by 5:30, so New River can call its next witness.

MR. STYERS: Before we do that, I do want to make sure the record is complete. The Commission issued an Order on July 7th excusing the appearance of Witness David Stark and accepting prefiled rebuttal testimony into the record. I would like to formally move here in the hearing that that prefiled rebuttal testimony of David Stark, consisting of nine pages in question and answer format, and one exhibit, be accepted into evidence in the record, of the docket, and to be copied into the record as if orally given on the witness stand.

COMMISSIONER KEMERAIT: And, Mr. Styers, can you double-check to see if it's one exhibit or two exhibits because I want to make sure that we are correct.

MR. STYERS: I will. Excellent point.

COMMISSIONER KEMERAIT: Okay.

MR. STYERS: My correction. It is nine pages in question and format and two exhibits. Thank you.

COMMISSIONER KEMERAIT: So your motion is allowed. The rebuttal testimony of Mr. Stark filed on June the 23rd of 2023, consisting of nine pages and two exhibits that are attached, will be admitted into the record.

(WHEREUPON, Stark Rebuttal Exhibits 1 and 2 are marked for identification as prefiled and received into evidence.)

(WHEREUPON, the prefiled rebuttal testimony of David Stark is copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-34, SUB 54
DOCKET NO. E-34, SUB 55

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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	**REBUTTAL TESTIMONY OF** **DAVID STARK** **ON BEHALF OF** **NEW RIVER LIGHT AND POWER**

June 23, 2023

Q. Please state your name and business address.

A. My name is David Stark. I am a Certified Public Accountant and employed as Managing Director of KPMG. My business address is 500 West 5th Street, Suite 800, Winston-Salem, North Carolina 27101.

Q. What is KPMG?

A. KPMG is the fourth largest accounting firm in the United States and helps manage over seventy-eight percent of all US public audits. Around the world, KPMG firms operate in 143 countries and territories, and collectively employed more than 265,000 partners and other people, serving the needs of business, governments, public-sector agencies, and not-for-profits.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Applicant, Appalachian State University ("ASU") d/b/a New River Light and Power ("NRLP").

Q. Please describe your professional background and education.

A. A copy of my resume is provided as Stark Rebuttal Exhibit No. 1. My accounting practice regularly involves advising clients on tax compliance issues, including Unrelated Business Income Tax (UBIT) obligations of not-for-profit institutions.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony relates to the application filed on December 22, 2022, by ASU d/b/a NRLP for adjustment of general base rates and charges applicable to electric service effective as of January 21, 2023, in Docket No. E-34, Sub 54, and to the Petition of ASU d/b/a NRLP for an Accounting Order to Defer Certain

Capital Costs and New Tax Expenses, in Docket No. E-34, Sub 55. Specifically, my rebuttal testimony provides the factual context for the decisions made regarding the UBIT obligation of ASU d/b/a NRLP, my professional opinion that those decisions were reasonable and prudent, and my conclusion that that the liability was unexpected based on what was reasonably known at the time and therefore fully justifies the deferral request for UBIT as set forth in the application.

Q. What is UBIT?

A. UBIT is defined as "income from a trade or business, regularly carried on, that is not substantially related to the charitable, educational, or other purpose that is the basis of the organization's exemption."[1]

Q. What information or knowledge do you have regarding the UBIT obligation of Appalachian State University d/b/a NRLP?

KPMG has been the tax compliance advisors and accountants for Appalachian State University (ASU) for many years. In addition to providing tax compliance and consulting services to ASU, I also provide services to six other UNC system schools or their affiliated non-profit organizations along with approximately three dozen other universities throughout the southeastern United States. We monitor state and federal tax laws and their changes, communicate regularly with the senior administration of ASU, especially its Office of the Controller, respond to tax

[1] IRS website. irs.gov/charities-non-profits/unrelated business-income tax

compliance questions, and prepare and file income tax returns for ASU. As explained in more detail below, KPMG advised ASU on the changes in the law created by the Tax Cuts and Jobs Act regarding UBIT. As part of that process, ASU asked KPMG to take a fresh look at other sources of revenue that could potentially subject ASU to an income tax liability, including the net revenues generated by NRLP. We also discussed with and advised ASU management regarding the merits and chances of success of seeking a private letter ruling from the IRS on this issue. In summary, we have worked closely with ASU for over four years on this issue and are extremely familiar with the applicable law and policy as it pertains to whether NRLP revenues are subject to UBIT.

Q. Historically, were net revenues generated by university-owned utility systems subject to UBIT?

A. Not to our knowledge. We reviewed pages of a report that my predecessors at KPMG provided to ASU in the early 1990s. The report appears to have been commissioned by the UNC System Office as part of a larger unrelated business income tax review for all 16 campuses. That report concludes, "the University should not report its utility income as unrelated business income." Our review of those pages, and understanding of the long-standing practices of ASU, indicate that net revenues from utility operations had not been reported as UBIT, and it is my professional opinion that ASU reasonably relied on the advice of its outside professional tax advisor at that time in deciding not to pay that tax during that period. To our knowledge, neither ASU's outside accountants/advisors, nor the

State Auditor, nor the Internal Revenue Service (IRS) opined (or even expressed a concern that) the net revenues of ASU d/b/a NRLP were subject to UBIT since that advice was provided. My professional opinion is that the prior decision not to pay UBIT based on tax advice in 1995 was reasonable based on what was known at that time.

Q. Was there, however, a change in the law regarding UBIT?

A. Yes. The Tax Cuts and Jobs Act (TCJA), Public Law 115-97, which became effective in 2018, made some significant and material changes in the criteria for the applicability or exemption from UBIT. This spurred a number of universities, including ASU, to take a fresh look at prior tax positions taken on revenue generating activities.

Q. In that context, did KPMG then proceed to analyze whether the net revenues of ASU d/b/a NRLP were subject to UBIT?

A. Yes. We addressed this issue in a memo dated June 26, 2019, addressed to David Jamison which is attached hereto as Stark Rebuttal Exhibit No. 2.

Q. What was the conclusion of that analysis?

A. It concluded that the revenue generated by electricity sold to the general public is more likely than not unrelated business income (UBI) subject to UBIT..

Q. Are you familiar with this memo and do you believe, in your professional opinion, that its analysis and conclusion are correct?

A. Yes. The memo was drafted by Donald (Dee) Rich, a now-retired KPMG tax partner, and Shawn Hutchinson, a Senior Tax Manager who works with me. While

I did not prepare the memo, I reviewed it before it went to Mr. Jamison, and was aware of the underlying issues at the time the memo was being drafted. Additionally, I do believe, in my professional opinion, based upon my training, knowledge, and years of experience in this field, that its analysis and conclusions are correct.

Q. Did KPMG advise ASU regarding whether it could or should challenge or seek further clarification regarding its UBIT obligation?

A. Yes, given the unexpected and material impact on NRLP's finances, we discussed ASU's options with Mr. Jamison and explained to him that it was more likely than not that the IRS would find the net revenues of NRLP to be taxable. We also advised him that a request for private letter ruling on the issue would be both an expensive and lengthy proposition and not likely to be successful.

Q. What do you mean by "more likely than not?"

A. It is a technical standard found in a number of places. The Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 740-10 which addresses "Accounting for Uncertain Income Tax Positions" is one example. Tax positions that meet the more-likely-than-not (MLTN) recognition threshold are measured as the largest amount of tax benefit that is more than 50 percent likely of being realized upon settlement with the taxing authority. A liability on the financial statements must be recorded for those amounts that do not meet this threshold and reported to the IRS on Form UTP in some circumstances. Form UTP is used by US corporations that have assets greater than $10 million to report their uncertain tax positions recorded on their financial statements to the IRS on an annual basis. Additionally, the AICPA Statements on Standards of Tax Services define MLTN as a greater than 50% probability of success if challenged by the IRS. Different clients may have different risk tolerances, but, in our experience, we find that most public agencies/institutions tend not to take UBIT tax positions that do not meet the more-likely-than-not threshold, even when a lower threshold can be used, because ASC 740 would necessitate recognizing a liability on their financial statements for the amount that does not meet the MLTN level of assurance, and disclose to the IRS those positions on Form UTP . Therefore, the consequences of taking a position below MLTN can include increasing the likelihood of IRS audits (which can be both expensive and time-consuming to respond to), as well as financial penalties and interest if the tax position is rejected by the IRS.

Q. **In your professional opinion, based upon your training, experience and knowledge, was it reasonable for ASU to pay the UBIT on the net revenues of NRLP beginning in 2019?**

A. Yes, it was.

Q. **You used the term "unexpected" in a previous answer; the Public Staff has taken the position that that this liability was not unexpected; do you agree?**

A. Absolutely not. For the reasons discussed above, ASU had reasonably relied upon the advice of outside tax professionals in not paying UBIT prior to revisiting the issue in 2019, with no adverse consequences and resulting in a lower cost of service and rates to the customers of NRLP. And no one – not even tax professionals – are

MR. STYERS: Thank you very much. New River Light and Power would like to call to the witness stand Vice Chancellor David Jamison, please. Would you please state your name and position --

COMMISSIONER KEMERAIT: Let me go ahead and get him sworn in first.

MR. STYERS: I'm sorry. I'm sorry.

COMMISSIONER KEMERAIT: And I apologize. I think I just mispronounced your name. Is it Jamison, Mr. Jamison?

MR. JAMISON: That's correct.

COMMISSIONER KEMERAIT: If you can put your left hand on the Bible and raise your right hand.

DAVID JAMISON;
having been duly sworn,
testified as follows:

DIRECT EXAMINATION BY MR. STYERS:

Q Mr. Jamison, would you please state your name, position, and employment for the record?

A I'm David Jamison. I'm the University Controller and also serving as the interim Associate Vice Chancellor for Financial Operations at Appalachian State University, Boone, North Carolina.

Q Have you caused to be filed, prefiled in this docket, rebuttal testimony consisting of 17 pages in question and answer format?
A Yes.
Q Was that testimony prepared by you or under your direction?
A Yes.
Q Okay. Do you have any corrections or additions to your testimony?
A No.
Q Was there one exhibit identified in and filed concurrently with that rebuttal testimony?
A Yes.
Q Is that exhibit true and accurate in representing what it purports to represent, to the best of your knowledge?
A Yes.

MR. STYERS: At this time, we would ask that the prefiled rebuttal testimony of David Jamison be moved into evidence in the record, in this case, and copied into the transcript as if given orally from the stand, and that the one exhibit be marked as Jamison Rebuttal Exhibit 1 for identification purposes.

COMMISSIONER KEMERAIT: And Mr. Styers, I'm going to have you restate your motion because I just double-checked and his -- he has two exhibits, so I assume that you would like to have two exhibits --

MR. STYERS: I would. Thank you very much.

COMMISSIONER KEMERAIT: -- for identification purposes.

MR. STYERS: I handed Mr. Halley my rebuttal testimony notebook when he was trying to answer Mr. Clodfelter's questions.

COMMISSIONER KEMERAIT: Right. So Mr. Jamison's rebuttal testimony filed on June the 23rd of 2023, consisting of 17 pages, will be copied into the record as if given orally from the stand.

MR. STYERS: And two exhibits.

COMMISSIONER KEMERAIT: And his two exhibits will be marked for identification purposes as prefiled.

(WHEREUPON, Jamison Rebuttal Exhibits 1 and 2 are marked for identification as prefiled.)

(WHEREUPON, the prefiled rebuttal testimony of David Jamison is copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-34, SUB 54
DOCKET NO. E-34, SUB 55

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

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	**REBUTTAL TESTIMONY OF** **DAVID JAMISON** **ON BEHALF OF** **NEW RIVER LIGHT & POWER**

June 23, 2023

Q. Please state your name and business address.

A. My name is David Jamison. I am the Interim Associate Vice Chancellor for Finance and Administration and University Controller for Appalachian State University ("ASU" or "University"). My office address at the University is BB Dougherty Administration Building, 438 Academy Street, Boone, NC 28607.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Applicant, Appalachian State University ("ASU") d/b/a New River Light and Power ("NRLP").

Q. Please describe your professional background and education.

A. I earned my MBA from Appalachian State in 2002. I am a Certified Management Accountant. I have been employed by ASU since 2005, as Director of Accounting from 2009 to 2012 and as University Controller since 2012. This year, my responsibilities include serving as Interim Associate Vice-Chancellor for Finance and Administration for the University. A copy of my resume is provided as Jamison Rebuttal Exhibit No. 1.

Q. What are your responsibilities as University Controller?

A. I am responsible for the oversight of financial operations and accounting for the University, including accounts receivable, accounts payable, e-commerce, cash management, payroll, tax compliance, accounting services, post award contract and grant compliance, and financial reporting. In this position, I lead a team of accounting professionals to produce accurate accounting records and timely financial statements. I also serve as the University's Internal Control Officer.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the prefiled testimony of the following witnesses in these dockets:

- Joint Direct Testimony of Public Staff witnesses Sonja R. Johnson and Iris Morgan as it pertains to the UBIT liability deferral.
- Direct Testimony of John R. Hinton as it pertains to return on equity.
- Direct Testimony of Appalachian Voices witness Jason W. Hoyle as it pertains to ASU's financing strategy and efforts, process and ability to issue debt, return on equity, and public finance principles in general.

Q. Are the financial statements of ASU audited?

A. Yes, every year. As one of the sixteen constituent universities of The University of North Carolina System, we are audited each year by the North Carolina Office of the State Auditor.

Q. Has the State Auditor provided a "clean" audit of ASU for each of the past several years?

A. Yes, those audits reports can be found at https://controller.appstate.edu/financial-reports .

UBIT LIABILITY DEFERRAL REQUEST

Q. Does ASU file tax returns with the federal Internal Revenue Service (IRS) and the North Carolina Department of Revenue (NCDOR)?

A. Yes. Although ASU is a governmental entity and a public institution of higher education, which is not subject to Federal or State income tax, we have certain filing requirements with the IRS and NCDOR, including but not limited to the filing of income tax returns for Unrelated Business Income Tax (UBIT).

Q. Does ASU have an external tax compliance advisor or accounting firm on which it relies to file its tax returns accurately and in compliance with the applicable tax laws?

A. Yes, KPMG has been ASU's long-time accountants and tax compliance advisors.

Q. Explain what steps ASU took after the Tax Cuts and Jobs Act (TCJA) became effective in 2018 to verify its obligations for UBIT arising from the net revenues of NRLP?

A. We reached out to KPMG for assistance with interpreting and implementing the new requirements of the TCJA and asked KPMG to provide an updated assessment of our exposure to UBIT tax liabilities. We met, explained the basis for our not having paid UBIT on utility revenues in the past (which was based on an earlier analysis performed as part of a UNC System-wide UBIT review), and described the operations of and electric service sales by NRLP. In response to our request, KPMG produced the memo attached to David Stark's testimony as Stark Rebuttal Exhibit No. 2. It concluded that the revenue generated by electricity sold by NRLP to the general public more likely than not was taxable unrelated business income.

Q. Did ASU expect to have UBIT liability for the net revenues of NRLP?

A. No. Even before I arrived at ASU in 2003, University leadership relied on a UNC System-wide UBIT review performed in the 1990s. This analysis (also performed by KPMG) considered the net revenues of NRLP to not be subject to UBIT. Before my tenure as controller, the two previous controllers completed the 990-T filings for the University. They relied on the conclusion provided in the original analysis maintained in the University's records. Similar to many other tax scenarios and analysis, the treatment of revenues for UBIT purposes depends on the specific facts and circumstances of the entity and on the knowledge and judgment of individuals who prepared the 990-T at that time. All of us, myself included, relied on the guidance we had previously received and had on file.

To provide more background: when I first became the University Controller, ASU had no dedicated position focused on tax and tax compliance. Those responsibilities were divided among the accounting staff as a part of their other duties. I advocated for and hired the University's first tax accountant, and we now have developed a Tax Compliance Office comprised of three positions who focus on tax issues specific to the University. Since developing this group, we have updated and modified processes for the purpose of reducing the risk of non-compliance. Over time, this group of employees and I have regularly reviewed compliance matters and gained more knowledge in areas like UBIT and its applicability to University activities. Our office continuously strives to improve our professional knowledge and processes. Many of our peers in the UNC System have similarly evolved.

Q. What did ASU do after receipt of that memo for KPMG?

A. After considerable discussion both with KPMG and internally with senior management at ASU, we agreed that this liability was a legal obligation of the University and amended returns should be filed and the unpaid tax liabilities should be satisfied, both going forward and for six years in arrears in accordance with IRS regulations. As a Certified Management Accountant and accounting professional, I am obligated to take corrective action when the facts indicate the possibility of non-compliance is present and creates a significant risk to the University. Ethics are a core tenant in the accounting profession and to disregard the information we had received, and agreed with, during the review process would not meet our ethical standards. We are obligated to protect the interests of the students, University, and the State of North Carolina through compliance with all laws, regulations, and polices the University is required to adhere to.

Q. Has ASU considered challenging KPMG's analysis or otherwise seeking additional clarification from the Internal Revenue Service; bringing suit; or taking similar actions?

A The University considered its options and consulted with KPMG, but ultimately chose, in its judgement, not to challenge the IRS. After a thorough review of the applicable Federal laws and tax regulations with our accounting firm, leadership made the carefully considered decision not to take further action and has followed the professional tax advice it received. Furthermore, other peer institutions in the UNC System pay UBIT on electric utility revenues and other unrelated business activity. Moreover, I understand that the current cost of a private letter ruling is likely to be over $30,000, not including other direct and indirect expenses. The process can take several months and can increase in cost based on the length and nature of a challenge. Given our belief that the likelihood of success of any such challenge was small, we did not believe that it was a prudent expenditure of public funds to pursue that challenge and decided to follow the applicable regulations to file amended returns and pay the tax. Even if the university desired to pursue a letter ruling, based on our understanding of the regulations, we would still be obliged to pay the tax liability until a favorable ruling was provided, which was not likely based on the nature of the utility's activity and our understanding of the tax law as explained by KPMG.

Q. **The Public Staff criticizes ASU d/b/a NRLP for not seeking a deferral of the UBIT liability sooner and claims that the request is not timely; how do you respond to this position?**

A. First, we thought coordinating this request at the same time as our next rate case was a logical and efficient time at which to focus management attention on the totality of rate issues and expenditure of resources. The Public Staff fails to recognize that NRLP -- unlike the Duke Energy utilities -- is a small system with limited staff and administrative resources. During 2020 and 2021, we were in the process of transitioning our power supply arrangement from Duke Energy Carolinas for the first time in the history of the utility. This transition also involved entering into a new Interconnection Agreement and Wholesale Energy Delivery Services Agreement with BREMCO and upgrading our substations from 44kv to 100kv. Second, we are advised that both in-house university counsel and outside regulatory counsel are unaware of any deadline for seeking recovery of unexpected expenses that have a material impact on the finances of the utility. The important regulatory date is when amortization of deferral begins and ends – a decision made in the rate case – and not when the deferral petition is filed. And third, these were funds actually paid to the state and federal government as owed taxes. Other utilities are allowed to recover through rates their taxes as a cost of service; so NRLP should be too.

Q. On your third point, the Public Staff's accounting testimony states that the requested deferral amounts do not accurately reflect NRLP's actual tax liability; do you agree?

A. The Public Staff's testimony in this regard was unexpected, and upon receiving it, we immediately verified the amount of tax liability for which recovery is being requested. As a starting point, it may be helpful to explain the process by which ASU calculates UBIT: First, after the year-end closing, our Tax Compliance office runs a separate profit and loss report for each business unit of the University. Then, we make tax adjustments to the P&L because some income is excludable under the IRS regulations, such as interest income, from unrelated business income tax calculations. We work with each unit to gather information that will be used to allocate the revenue and expenses between UBI and non-UBI activities. For NRLP, the allocation is based on the percentage of power usage. Income derived from the University and Town of Boone's utilities consumption is treated as non-UBI, which is exempt from unrelated business income tax. Next, we prepare a Schedule ("Schedule M" for 2018 and 2019, "Schedule A" starting in 2020) for each business unit. The Tax Cuts and Jobs Act of 2017 requires tax-exempt organizations subject to the UBI tax to compute unrelated business taxable income, including any new operating loss deduction, separately for each trade or business (referred to as a "silo"). Finally, schedules with taxable income are consolidated on a Form 990-T

Tax Return. The schedules, along with other required forms and supporting documentation, are filed with the tax return.

Q. Using this process, ASU incurred and paid what amounts of UBIT tax liability for NRLP for 2019, 2021, and 2022?

A. The amount of UBIT paid, after crediting all year-end true-ups, was $931,544.59, as shown on Jamison Rebuttal Exhibit No. 2 attached hereto. This is an update and correction to Exhibit REH-8 attached to Randy Halley's testimony, and this revised number has been incorporated in Mr. Halley's calculations attached to his rebuttal testimony.

PUBLIC FINANCING, CAPITAL STRUCTURE, AND RATE OF RETURN

Q. The prefiled testimony of Jason W. Hoyle on behalf of Appalachian Voices "propose[s] 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; how do you respond to this proposal and Mr. Hoyle's testimony in general?"

A. With all due respect to what Mr. Hoyle may know about sustainability issues and energy policy and while I value the concerns expressed by our ASU alumnus and former faculty, his pre-filed testimony reveals a lack of knowledge and understanding of public finance, economics, debt and equity markets, financial risk assessment, and capital structure. This is perhaps understandable given his absence of training or experience in these areas, but I think it is important to preface my rebuttal on this issue with these observations.

ASU – as a public institution with total assets of over $1.3 billion and total annual revenue of over $500 million -- has a very carefully considered financing plan and capital structure. We are acutely aware of our role and duties as stewards of these public funds, and work diligently every day to deploy these resources in a manner that furthers our mission and that benefits all our stakeholders and the State of North Carolina. The university is bound by its Debt Management policy, which has been established to assist the university in managing debt on a long-term portfolio basis and within the bounds of the policies established by the Board of Governors of the University of North Carolina and the State. This policy focuses on strategically managing the University's debt capacity and was implemented to provide a framework for the University's Board of Trustees and management staff to meet the following objectives:

1. identify and prioritize projects eligible for debt financing;
2. limit and manage risk within the debt portfolio;
3. establish debt management guidelines and quantitative parameters for evaluating financial health, debt affordability, and debt capacity;
4. manage and protect the University's credit profile to maintain a strategically optimized credit rating; and
5. ensure the University remains in compliance with post-issuance obligations and requirements.

In making our decisions, we look not only at current projects, but also consider long-term capital needs, long-term yield curves and trends in financial markets, and a variety of financing options, including their respective risks and costs in the context of our debt capacity as required by our Debt Management policy, among other considerations. We then use our collective best judgment, after both consultation with our Financial Advisors and Bond Counsel and considerable internal deliberation, "to develop a comprehensive financing strategy that optimizes capital structure" to meet capital needs considering relative long-term risks and costs. This decision making and evaluative process is reflected in the University's capital plans that are submitted to the State and carries over to the individual project level as we file the necessary information with the State for approval. Debt issuance for utility equipment and infrastructure has been delegated to the university's Board of Trustees by the UNC Board of Governors and the General Assembly; however, debt for NRLP is still a consideration when the university plans capital projects and evaluates institutional level debt capacity.

The University is limited in the amount of debt that can be added to its balance sheet without exceeding target metrics defined in our Debt Management policy, which establishes our debt capacity. Furthermore, the University must consider its overall debt affordability. At the institution level down to the project level, responsible financial managers must understand what debt the University can afford and pay with current or future resources and remain within our debt capacity. Clearly, our decisions are neither arbitrary nor haphazardly made.

To be more specific -- as it pertains to NRLP in this rate case -- the NRLP management likewise considers themselves as stewards of these public assets in providing safe, reliable, and affordable electric utility service not only to ASU as a customer but also to the off-campus residents and businesses in the Boone area.

We use the same care in our financial decisions regarding NRLP as we do for the University as a whole and must follow the same principles and targets established by our Debt Management policy when debt is issued for the utility operations. Finally, I should note that ASU, as a customer, has an interest in keeping NRLP's rates as low as practicable for the benefit of our students and the institution while recognizing the operational needs of the utility.

Q. How would you describe the process for ASU's decisions regarding the issuance of debt?

A. Issuing debt for the University can generally be a lengthy process beginning with the approval of a capital project. The University has some limited delegated authority to pursue capital projects up to $750,000. These are called "informal projects" and the University would rarely if ever use debt financing on projects of this size; thus, those projects would be paid from existing fund balances. Projects above $750,000 are subject to an approval process administered by the UNC System Office and the Office of State Budget and Management (OSBM). Debt financing for these projects primarily depends on the source of funds available and the size of the project. Most of these smaller projects, less than $2 to $3 million, are funded by carryforward receipts or repair and renovation appropriations allocated by the General Assembly. Auxiliary (self-supporting) units (like NRLP) may fund these projects through reserves and available funds. The finance and budget staff work with the University's Design and Construction group on a continuous basis to review and prioritize the sources of funds available for projects based on the most immediate needs to support the goals and strategic direction outlined by University leadership's capital plan. Other projects may be identified through an immediate need or emergency situation and may require immediate prioritization but are still subject to the same approval requirements.

Capital projects above the University's delegated authority are also submitted to the Board of Trustees and the Board of Governors for approval. When a project's scope and cost reach a level that is unable to be funded with existing resources or that may not be eligible to receive capital appropriations, management begins to evaluate various financing options legally available for the project. Once the need to issue debt is identified, the University must pursue approval through established processes. First the debt is approved through a borrowing resolution by the University's Board of Trustees. Next the proposed debt financing is reviewed and approved by the UNC Board of Governors. The board analyzes each project individually on a standalone basis. If an institution is unable to demonstrate that existing or future revenues associated with a project are not sufficient, the project will not be approved. After Board of Governors approval, the proposed debt is approved by the General Assembly and the Director of the Budget.

In the case of debt related to utility operations, the State and Board of Governors has delegated authority to the University Boards of Trustees to issue debt for equipment and infrastructure, *provided* that the utility supports the debt service solely from revenues generated by the utility so that it does not encumber or burden the Institution or the State. This means that the University, in consultation with its financial advisors and bond counsel, takes the same steps in analyzing the ability for a project undertaken by NRLP to service the debt from its available funds. As an independent operation, NRLP must maintain an appropriate level of cash and equity to be able to support its debt service obligations and maintain its fixed operating costs in instances when revenue streams may unexpectedly decline. (The unexpected increase in natural gas prices in December followed by the recent unseasonably warm winter is such an example, as discussed more below.)

Lastly, I will note that a Debt Capacity Study must be produced each year as required by statute that projects capacity over a 5-year period for the entire UNC System and Appalachian State University. The study is presented to UNC Board of Governors as required. It also outlines the debt ratios the University is required to set targets for in its Debt Management Policy.

Q. What are some of the considerations or factors that are considered regarding whether, and at what terms, to issue public debt?

A. When evaluating financing options, there are numerous factors that are taken into consideration. These include the size of the project and total cost, the term of the borrowing, the availability of existing or projected revenues to service the debt, the current interest rate environment, and the size of other offerings in the market, in addition to the overall outlook of the public higher education environment.

General Revenue bonds are serviced from unrestricted available funds, which differs from utility system debt that must be serviced exclusively from revenues generated by the utility system. As a prudent measure the university targets a coverage ratio between 1.25x and 1.3x. The General Trust Indenture for Utility system bonds requires a ratio of *at least* 1.25x coverage. Again, as a prudent measure, management may budget a higher target to allow for fluctuations in revenues and ensure that sufficient capital and cash are maintained to service the debt and for contingencies.

Q. Why is it important to retain and hold certain levels of capital and operating cash reserves?

A. As already mentioned, first, one reason is to ensure funds are available to service the debt and minimize the risk of default. Second, from NRLP's perspective -- where most of the financing is from retained earnings because additional debt is not easily and quickly available for the reasons I explain in this testimony -- available capital is essential for contingency and emergency purposes. As a small utility with only five substations, NRLP does not have a lot of lot of redundancy, and funds for contingencies and emergency repairs/replacements need to be available. Third, operating cash reserves must be sufficient to manage cost volatility, especially in the cost of purchased power. Natural gas price spikes, coupled with the regulatory lag tine of cost recovery, can create serious cash flow problems for NRLP. For example, this past winter NRLP did not have sufficient cash reserves to pay for its purchased power and had to rely on short-term emergency borrowing and seek from the Commission an interim PPA – measures we try to avoid. Finally, I'll note that rates cases are becoming increasingly expensive and occupy considerable management attention and resources– especially for a small utility like NRLP – so regulatory lag time is also a very real issue. At a minimum, I believe NRLP should maintain at least three- to six-months operating cash reserves, ranging from $4 million to $8 million, depending upon the time of year.

Q, Given those factors, is Mr. Hoyle correct in his assertion that NRLP capital needs can simply be met with more debt and less dependence on retained earnings?

A. No. In considering the request in this rate case, it is important to recognize that while NRLP is a component of Appalachian State, the utility does not fully realize the benefits of the University's resources and available funds, particularly as related to debt. Under the delegated authority, as mentioned before, NRLP debt must be serviced exclusively from utility revenues. This means that even though NRLP may have access to favorable interest rates, it also needs to maintain the appropriate levels of cash reserves to meet operating, capital, and debt service obligations and to maintain the required ratio as outlined in the General Trust Indenture and as I have previously explained.

Q, Should these same factors be considered in the context of determining the rate of return NRLP should be given an opportunity to earn?

A. Yes. Because rates have been kept low and not increased on a frequent basis, NRLP reserves have been depleted to the point where there is increased risk that it would not be able to recover from a disruption in operations or be able to adjust to changes in the economic environment and cannot rely on the University to cover shortfalls. NRLP, through the ratemaking process, needs to be able to re-establish and strengthen those reserves rather than maintaining the status quo. I am not a utility economist, but I have read and agree with Mr. Halley's rebuttal testimony; it appears that the Public Staff's recommended ROE is below what the financial markets expect and what other utilities are allowed to earn. In my opinion, requiring a return on equity below what other distribution-only utilities can earn is not a fiscally responsible stance to take for reasons previously explained. Moreover, assuming NRLP would encounter no issues if it were limited to an ROE less than other regulated utilities ignores basic economic realities of how capital is deployed on a risk/return-adjusted basis.

Q. **Doesn't NRLP provide some of its net earnings to the University Endowment Fund?**

A. Yes; however, that does not mean it is appropriate to stop most or all of its payments to the Endowment and instead use net earnings solely to finance capital projects or operating cash needs. First, the payment of earnings into the endowment fund is required by N.C.G.S. § 116-35, which provides, "Any net profits derived from the operation, or any proceeds derived from the lease or sale, of such power plants and distribution systems are appropriated and shall be paid into the permanent endowment fund held for the institution as provided for in G.S. 116-36." The North Carolina General Assembly clearly intended for university utility operations to be a source of funding for university endowments. It is analogous to paying dividends to stockholders – there is no guarantee or contractual right of the endowment to receive a certain level of payments from the utility's earnings, but any amount above the utility's long-term internal capital and operating needs must go to the endowment. In this respect, NRLP should not be treated differently from an investor-financed utility.

Q. Shouldn't NRLP just stop making payments to the Endowment and accept a lower overall rate of return?

A. As a general proposition, capital for infrastructure is deployed based upon a risk-adjusted return on that investment, regardless of the source of that capital, or, said another way, rate of return should be commensurate with that of other investment opportunities with similar risks. The Endowment contributions should not affect this analysis Operating a utility utilizes the University's resources (for which there are opportunity costs in the deployment of those resources), imposes service obligations and risks of necessarily recovering from service interruptions, and creates financial risks from the regulatory lag on recovery of its utility costs and/or a potential shortfall in cash flow. The University, like any utility owner, should receive a reasonable return for those risks. It is worth understanding the possible consequences of cutting the overall rate of return to the 6.07% recommended by Mr. Hinton in this case. Public Staff Accounting Exhibit 1, Schedule 1, shows that the reduction in return on capital recommended by witness Hinton would reduce NRLP's revenue by almost $400,000 per year, which would be a significant impact on the endowment and NRLP's ongoing capital and cash flow needs.

Q. DOES THIS CONCLUDE YOUR PREFILED REBUTTAL TESTIMONY?

A. Yes.

BY MR. STYERS:

Q Mr. Jamison, have you prepared a three-page summary of your prefiled rebuttal testimony that's been filed in this docket?

A Yes.

MR. STYERS: Presiding Commissioner, I would ask that that summary also be copied into the record as if provided orally from the stand.

COMMISSIONER KEMERAIT: And Mr. Jamison's summary will also be copied into the record.

(WHEREUPON, the summary of rebuttal testimony of David Jamison is copied into the record as if given orally from the stand.)

SUMMARY OF REBUTTAL TESTIMONY OF DAVID JAMISON
ON BEHALF OF NEW RIVER LIGHT & POWER
DOCKET NO. E-34, SUBS 54 & 55

I am the Interim Associate Vice Chancellor for Finance and Administration and University Controller for Appalachian State University ("ASU").

This summary does not address my rebuttal to the Public Staff's testimony regarding the requested deferral account recovery of Unrelated Business Income Tax (UBIT), as that matter has been settled.

ASU has a very carefully considered financing plan and capital structure. In making financing decisions, we look not only at current projects, but also work with our financial advisors to consider long-term capital needs, long-term yield curves and trends in financial markets, and a variety of financing options, including their respective risks and costs in the context of our debt capacity as required by our Debt Management policy. We then use our collective best judgment, working with our financial advisors and bond counsel, to develop a financing strategy that optimizes capital structure to meet capital needs, considering relative long-term risks and costs.

Issuing debt for the University can be a lengthy and detailed process involving the UNC System and other State agencies for approval. Internally, the University is limited in the amount of debt that it can issue without exceeding target metrics defined in our Debt Management Policy. The University must consider its overall debt affordability, for which considerations are more complex and include more than just debt capacity.

Regarding debt related to utility operations, the University Board of Trustees may issue debt for equipment and infrastructure, *provided* that the utility supports the debt service solely from revenues generated by the utility. NRLP must maintain an appropriate level of cash and equity to be able to support its debt service obligations and maintain its fixed operating costs in instances when those costs increase and/or when revenue streams unexpectedly decline.

From NRLP's perspective -- where most of the financing is from retained earnings because additional debt is not easily and quickly available for these reasons I have explained -- available capital is essential for contingency and emergency purposes. As a small utility with only five substations, NRLP does not have a lot of redundancy, and funds for contingencies and emergency repairs/replacements need to be available. Also, operating cash reserves must be sufficient to manage cost volatility, especially in the cost of purchased power. Natural gas price spikes, coupled with the regulatory lag time of cost recovery, can create serious cash flow problems for NRLP.

For these reasons, NRLP capital needs cannot simply be met with more debt and less dependence on retained earnings. Although NRLP is a component of ASU, its debt must be serviced exclusively from utility revenues. This means NRLP needs to maintain the appropriate levels of cash reserves to meet operating, capital, and debt service obligations and to maintain the required ratios as outlined in the General Trust Indenture.

Because rates have been kept low and not increased on a frequent basis, NRLP reserves have been depleted to the point where there is increased risk that it would not be able to recover from a disruption in operations or be able to adjust to changes in the economic environment and cannot rely on the University to cover shortfalls. NRLP, through the ratemaking process, needs to be able to re-establish and strengthen those reserves.

For these reasons, setting an overall rate of return considerably lower than what other distribution-only utilities can earn is not a fiscally responsible position. Moreover, assuming NRLP would encounter no issues if it were limited to returns much lower than that of other regulated utilities ignores basic economic realities of how capital is deployed on a risk/return-adjusted basis. I believe that that the agreed upon 6.165% cost of capital, with a 9.10% ROE, is an acceptable compromise in the overall context of the settlement with the Public Staff.

MR. STYERS: Thank you very much. The witness is available for cross-examination.

CROSS EXAMINATION BY MR. MAGARIRA:

Q Good afternoon. Munashe Magarira, co-counsel for Appalachian Voices. Good afternoon, Vice Chancellor Jamison. As you note in your testimony, Appalachian State is subject to a debt management policy, correct?

A Correct.

Q And this informs how Appalachian State manages debt on a long-term portfolio basis, correct?

A That's correct.

Q Okay. I'm going to direct you to -- this is page 12, and this is line 17 through 21. Just let me know when you're there.

A I'm there.

Q Obviously, in your testimony, you, sort of, talk about the general process which, sort of, governs the approval of the issuance of debt on behalf of Appalachian State, but to confirm with respect to debt issuances for utility operations, specifically New River, approval for that debt issuance or issuances would be solely vested, I guess, within the authority of the Board of

Trustees?
A Provided that the debt that New River incurs does not bind the State, and that authority is delegated --
COURT REPORTER: Could you speak into the mic, please.
A Oh, sorry. Yes. Provided that the debt does not encumber the State, for the University, and they have delegated authority to New River Light and Power.
Q Right. So like a special obligation bond, basically, where you're having the bond be backed up by some sort of stream of revenues that's not, you know, the State saying we are guaranteeing this.
A Right.
Q Is that accurate?
A We call that pledge revenue.
Q Got you. Thank you. So, again, going back to the debt management policy, there's, obviously, some requirements and factors that, sort of, inform how the University system at Appalachian State can manage debt on its books. One of those, I guess, factors or ratios is the debt to

obligated resources ratio. Is that right?
A That's correct.
Q And obligated resources, in short, refers to any source of income or receipts of security in source of payment of bonds?
A It refers to an available funds calculation.
Q Okay, perfect. So, again, with respect to the, I guess, Debt Capacity Study, you mentioned this in your testimony, and I'm talking specifically about the debt to obligated resources ratio, which is about 1.5X. Is that right?
A That's the ceiling, if I remember correctly.
Q Okay. For the five-year study period that was the subject of the most recent Debt capacity Study, at no point does the, I guess, debt capacity exceed that ceiling of 1.5X?
A That's correct.
Q Okay.

MR. MAGARIRA: No further questions.

COMMISSIONER KEMERAIT: Well, you certainly did expedite cross-examination. Any questions from the Commission?

MR. STYERS: May I have --

COMMISSIONER KEMERAIT: Oh, I apologize,

Mr. Styers. Redirect.

MR. STYERS: May I just say very, very short.

REDIRECT EXAMINATION BY MR. STYERS:

Q Mr. Jamison, I think you were asked a question which it was referenced, and I know others have been referenced, that New River Light and Power has no equity investors. That's been part of questions that have been kind of a mantra. But, in fact, New River Light and Power does have an owner, does it not?

A That is correct.

Q And the owner is the owner of its equity, which is assets less its liabilities. Is that correct?

A That is correct.

Q And that owner's the State of North Carolina?

A Yes.

Q Okay. And when we think about risk-adjusted return, you know, owners are entitled to a risk-adjusted return on their equity, are they not?

A That would be correct.

MR. STYERS: No further questions.

COMMISSIONER KEMERAIT: Any questions from the Commission?

(No response)

COMMISSIONER KEMERAIT: Seeing none, there'll be no questions on Commission questions. So motions from New River in regard to Mr. Jamison?

MR. STYERS: New River would like to ask that the two exhibits that were attached to the rebuttal of David Jamison as Exhibits 1 and 2 be admitted into record as evidence.

MR. DROOZ: And, at this time, we would also like to move the Application of New River Light and Power and the Stipulation agreement into evidence.

MR. STYERS: And that Application to include all of the E-1 exhibits that were part of that Application.

COMMISSIONER KEMERAIT: Okay.

MR. STYERS: E-1 Schedules.

COMMISSIONER KEMERAIT: Seeing no objection, both of your motions are allowed.

(WHEREUPON, Jamison Rebuttal Exhibits 1 and 2, New River Light and Power Application, Exhibits and E-1 Schedules, and Agreement and Stipulation of Settlement are received into evidence.)

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

THE WITNESS: Thank you.

COMMISSIONER KEMERAIT: Before I conclude the hearing, are there any other matters that we need to address from any of the parties?

MR. FELLING: None from the Public Staff.

MR. STYERS: I'm not sure when the 270-day window is up but we are prepared, certainly, to provide proposed Orders and post-hearing briefs within 30 days of receipt of the transcript, unless the Commission would prefer that we try to do that on a more expedited basis.

COMMISSIONER KEMERAIT: So what we're going to be ordering is that proposed orders are due 30 days from notice of the mailing of the transcript. And before we conclude, I wanted to thank the attorneys and all of the witnesses for the really good work and information that was provided. And, also, for the professionalism in this hearing, and, also, we really appreciate the attorneys working with us to be able to finish the hearing today. I think that that was -- we appreciated that effort to have succinct cross-examination so we could get finished today.

So, with that, I'll go ahead and adjourn the hearing. And, again, thank you, everyone.

WHEREUPON, this hearing is adjourned.

C E R T I F I C A T E

I, TONJA VINES, DO HEREBY CERTIFY that the proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Tonja Vines
____
Tonja Vines