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December 22, 2022

Ms. A. Shonta Dunston
Chief Clerk
N.C. Utilities Commission
430 N. Salisbury Street, Room 5063
Raleigh, NC 27603

Re: ***New River Light and Power Company***
Direct Testimony of Randall E. Halley
Docket No. E-34, Sub 54

Dear Ms. Dunston:

Attached hereto, on behalf of New River Light and Power Company, is the pre-filed Direct Testimony Randall E. Halley to be filed in the above-referenced rate case docket in support of the Application filed concurrently herewith.

If you have any questions concerning this filing, or exhibits thereto, please do not hesitate to contact me.

Sincerely,

M. Gray Styers, Jr.

M. Gray Styers, Jr.

cc: Mr. David T. Drooz
Mr. Randall E. Halley
Mr. Edmond C. Miller
Mr. Zeke Creech, NC Utilities Commission Public Staff
Ms. Jessica Heironimus, NC Utilities Commission Public Staff
Ms. Jennifer Harrod, NC Utilities Commission Staff

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	Annual Total CDD	Annual Total 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?

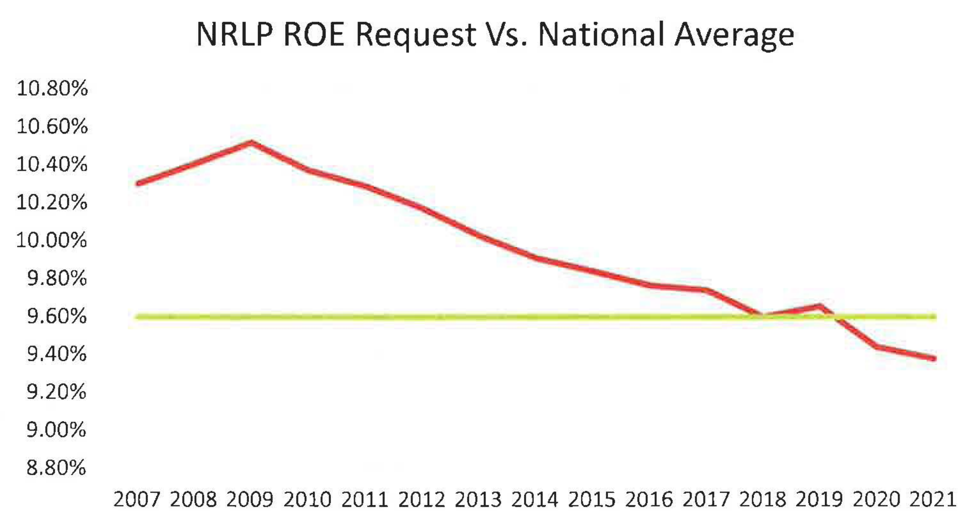
A. I use two recently approved ROEs from natural gas distribution utilities: Piedmont Natural Gas Company, decided on January 6, 2022, in Docket No. G-9, Sub 781, and Public Service Company of North Carolina, decided on January 21, 2022, in Docket No. G-5, Sub 632. These two utilities are similar to 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.