APPALACHIAN STATE UNIVERSITY
DBA NEW RIVER LIGHT AND POWER
DOCKET NO. E-34, SUB 46

DIRECT TESTIMONY OF RANDALL E. HALLEY

ON BEHALF OF
APPALACHAIN STATE UNVERSITY
DBA NEW RIVER LIGHT AND POWER

JULY 28, 2017

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 1613 Bimini Drive, Orlando, Florida 32806.

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

A. I am testifying on behalf of Appalachian State University d/b/a New River Light and Power ("NRLP") regarding its petition 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 26 years of experience in utility consulting and managing the financial planning efforts of the Orlando Utilities Commission. My primary areas of expertise are in revenue requirement, cost of service, rate design, feasibility analyses and power supply evaluations. In my position as Director of Strategic Planning for the Orlando Utilities Commission, I have presented testimony to the Florida Public Service Commission in Docket No. 080412-EG.

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

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

Q. PLEASE DESCRIBE NRLP'S ELECTRIC RESALE OPERATION.

A. NRLP operates an electric distribution system whose purpose is to provide low-cost and reliable power supply to Appalachian State University ("ASU"), residents and small businesses located in-and-around Boone, NC.

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 6.99%, which is based on a capital structure consisting of 50% common equity with a 9.75% return on equity; and 50% long-term debt at a cost rate of 4.23%.

- NRLP needs an immediate rate increase of $1,762,078, which equates to an overall increase of 8.50% over present rates as adjusted for anticipated changes in the Power Purchase Adjustment Clause ("PPAC").
- The rate increase should be implemented through base rates, including a re-setting of the base purchased power factor to cover 100% of the expected cost of purchased power. Based on the allocated cost of service analysis, the increase should be recovered through a 17.37% increase in residential rates, a 9.04% increase in commercial non-demand rates, a 14.70% increase in commercial demand rates, a 10.21% increase for customers shifted from the commercial demand rate to a newly proposed commercial demand high load factor rates and a 1.56% decrease to ASU Campus.

In addition, I am recommending the addition and modification of the following rate structures:

- To provide the appropriate price signal to those commercial customers with load factors at or above the NRLP system average load factor of 65%.
- To insure all distribution facility/customer specific costs for the ASU Campus are recovered and a pricing structure is established to assist ASU with its sustainability efforts, a master meter structure is proposed for the ASU Campus load. The ASU campus load is served solely from one substation and the energy metered at this substation would be used for billing purposes.
- NRLP will be moving toward LED security lighting and phasing out the use of the existing mercury-vapor, sodium-vapor and metal halide lights. A new LED security lighting rate schedule is proposed for this process to begin.

- To help collect some of the costs incurred by NRLP for various miscellaneous services, an increase in the Connect Charge and the addition of a Returned Payment Fee, Late Fee and Delinquent Fee are proposed.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. The remainder of my testimony is divided into three main sections as follows:

I. Fair Rate of Return
   a. Economic and Legal Guidelines for a Fair Rate of Return
   b. Cost of Common Equity
      i. Discounted Cash Flow Analysis
      ii. Comparable Earnings Analysis
      iii. Return on Equity Recommendation

II. Overall Cost of Capital
   a. Capital Structure
   b. Cost of Debt
   c. Overall Cost of Capital Recommendation

III. Cost of Service

IV. Rate Design

Q. PLEASE BRIEFLY DESCRIBE THE ECONOMIC AND REGULATORY POLICY CONSIDERATIONS YOU HAVE CONSIDERED IN DEVELOPING YOUR RECOMMENDATION CONCERNING THE 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 and the opportunity to earn 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 attract capital to meet future 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 investors receive a windfall, and the utility has an incentive to overinvest. If the return is set too low, adequate service is jeopardized because the utility will not be able to raise new capital on reasonable terms.

Since every equity investor 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 forms 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 that utilities compete with other firms in the market for investor capital. Historically, this case has provided legal and policy guidance concerning the return which public utilities should be allowed to earn:

In that case, the U.S. Supreme Court specifically stated that:

> "...the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital." (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, like other investors, must have an adequate return to invest in the utility. If ASU could not earn returns similar to the investor-owned utilities, then it would be better off investing in those other utilities.

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 estimate/calculate reasonable rates of return on equity. In this case, I have chosen to use the "Discounted Cash Flow" or "DCF" analysis and "Comparable Earnings Analysis."

Q. PLEASE EXPLAIN THE DISCOUNTED CASH FLOW MODEL

A. The DCF method is widely used for estimating an investor's required return on a firm's common equity. The DCF method is based on the concept that the price which the investor is willing to pay for an investment is the discounted present value or present worth of what the investor expects to receive as a result of investing in that company. This return to the investor is in the form of future dividends and price appreciation. However, price appreciation is only realized when the investor sells the investment, and a subsequent purchaser presumably is also focused on dividend growth following its purchase. Mathematically, the relationship is:

Let D = dividends per share in the initial future period g = expected growth rate in dividends

k = cost of equity capital

P = price of asset (or present value of a future stream of dividends)

$$\text{then } P = \frac{D}{(1+k)} + \frac{D\,(1+g)}{(1+k)^2} + \frac{D\,(1+g)}{(1+k)^3} + \ldots\ldots + \frac{D\,(1+g)}{(1+k)^t}$$

This equation represents the amount (P) an investor will be willing to pay for a share of common equity with a given dividend stream over (t) periods.

Reducing the formula to an infinite geometric series, we have:

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

Solving for k yields:

$$k = \frac{D}{P} + g$$

Q. PLEASE DESCRIBE HOW YOU SELECTED A PROXY GROUP FOR ESTIMATING PUBLIC SERVICE'S RETURN ON EQUITY.

A. Given the small size of NRLP, I believe it was important to focus on electric utilities that were all located in the eastern half of the United States as is NRLP. To be specific, I used the companies followed by Value Line as "Electric Utilities – East". Table 1 below is a list of the companies in my comparable group.

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Table 1: Comparable Group

Company Name
Dominion Energy
Duke Energy Corp New
NextEra Energy Inc
SCANA Corporation
Southern Co

Q. WHAT DIVIDEND YIELD DO YOU THINK IS APPROPRIATE FOR USE IN THE DCF MODEL?

A. I have calculated the appropriate dividend yield by averaging the expected dividend as provided by Value Line over the next 12 months divided by the most recent price as stated by Value Line. The data was taken from Value Line for the period May 15, 2017 through July 28, 2017. My results appear in Exhibit_(REH-1) and show an average dividend yield range of 2.9% to 4.9% for the comparable group.

Q. HOW DID YOU DERIVE THE EXPECTED GROWTH RATE?

A. A central component in the DCF Method is the expected growth in dividends. Over the long term, dividends cannot be paid out without a corporation first earning the funds paid out. Earnings growth is a key element in analyzing what, if any, growth can be expected in dividends. To derive the expected growth rate for use in the DCF model, I used the forecasted earnings growth rates from Value Line, Thomson and Schwab for each company. The range in average growth rates for my comparable group is 3.2% to 6.3%.

Q. WHAT IS THE INVESTOR RETURN REQUIREMENT FROM THE DCF ANALYSIS?

A. As can be seen on Exhibit_(REH-1), the DCF results for the comparable group range from 7.5% to 9.2% with an average ROE of 8.6% and a median ROE of 8.8%. Based on these results, a reasonable return to assume from the DCF analysis would be the average of 8.6%.

The above-stated DCF results represents only one analysis I used in the examination of the proper cost of equity to apply in the current rate case. I also used a Comparable Earnings Analysis.

Q. PLEASE EXPLAIN HOW YOU PERFORMED THE COMPARABLE EARNINGS ANALYSIS?

A. Exhibit_(REH-2) presents a list of historical and projected earned returns on equity of the comparable group over the period of 2016 through 2022. I picked this range to provide the Commission with at least one historical return and six years of forecasted returns.

Q. WHAT ARE THE EARNED RETURNS IN 2016 FOR YOUR COMPARABLE GROUP?

A. In 2016, the average ROE for the comparable group was 10.6%.

Q. WHAT IS THE EXPECTED ROE FOR THE COMPARABLE GROUP FROM 2017 THROUGH 2022?

A. For the period of 2017 through 2022, the average expected ROE is 11.7% and the median ROE is 11.5%.

Q. DO YOU HAVE ANOTHER COMPARABLE EARNINGS METHODOLOGY TO PRESENT IN THIS CASE?

A. Yes. I believe it important to look at the allowed ROE this Commission has granted to electric utilities in the recent past.

Q. WHAT RETURNS ON EQUITY HAVE BEEN ALLOWED BY THIS COMMISSION FOR ELECTRIC UTILITIES OPERATING IN NORTH CAROLINA?

A. On Sept. 24, 2013, in Docket No. E-7, Sub 1026, the Commission allowed Duke Energy Carolinas (DEC) an ROE of 10.2%. On May 30, 2013, in Docket No. E-2, Sub 1023, the Commission granted Duke Energy Progress (DEP) the same ROE of 10.2%. On May 25, 2016, the Commission allowed Western Carolina University a ROE of 9.25% in Docket No. E-35, Sub 45. On Dec. 22, 2016, the Commission allowed Dominion NC Power a ROE of 9.9% in Docket No. E-22, Sub 532.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE COMPARABLE EARNINGS ANALYSIS?

A. The financial performance of the comparable group provides a forecasted average earning of 11.7%. However, allowed returns from this Commission have been lower with the most recent at 9.9%. Based on these values, I believe a reasonable ROE from the comparable earnings analysis would be 10.8%. This is an average of the forecasted earnings of 11.7% and the most recent Commission allowed return of 9.9%.

Q. MR. HALLEY, WHAT IS YOUR ROE RECOMMENDATION IN THIS CASE?

A. The DCF analysis provided a ROE of 8.6%. The Comparable Earnings ROE, as stated above, should be 10.8%. Based on these results, I believe

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the proper ROE to allow NRLP in this case would be 9.7%. This is an average of the DCF ROE of 8.6% and the Comparable Earnings ROE of 10.8%.

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. NRLP's current capital structure is summarized in Table 2.

Table 2: NRLP Current Capital Structure

Capitalization Component	Ratio	Cost	Weighted Cost
Long-Term Debt	14%	2.52%	0.34%
Common Equity	86%	9.70%	8.37%
			8.72%

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 entirely of common equity would be unfair to NRLP's consumers. In general, Commissions across the country have granted overall rates of return based on capital structures that are comprised of roughly 50% common equity.

Q. WHAT IS YOUR RECOMMENDED CAPITAL STRUCTURE IN THIS PROCEEDING?

A. I am recommending a capital structure that consists of 50% equity and 50% debt.

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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 50/50 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 granted by this Commission as well as the current debt cost rate in the utility industry.

Q. WHAT COST OF DEBT HAS RECENTLY BEEN APPROVED BY THIS COMMISSION THAT HAS A CAPITAL STRUCTURE COMPARABLE TO NRLP?

A. In the 2016 general rate case of Western Carolina University, which is a sister institution to Appalachian State University, the Commission granted a long-term debt cost rate of 4.23%. This was a reasonable estimate for the cost of debt going forward since Western Carolina University had no long-term debt. Their capital structure was imputed at 50% debt and 50% equity, as proposed herein for NRLP.

Q. WHAT ARE THE PREVAILING COSTS OF DEBT THAT CURRENTLY EXIST FOR UTILITIES IN THE MARKETPLACE?

A. For this data, I turned to the Commission's June 2016 "Quarterly Review" of Selected Financial and Operational Data which is summarized in Table 3 below.

Table 3: Utility Costs of Debt

Line No.	Rating	Past 12 Months		Monthly Average	
		High	Low	April 2017	March 2017
1.	Aa	4.11	3.36	3.93	4.04
2.	A	4.27	3.57	4.12	4.23
3.	Baa	4.79	4.16	4.51	4.62

As shown in Table 3 above, the most recent utility debt rates range from 3.93% to 4.62%, with an average of 4.24%.

Q. WHAT IS YOUR RECOMMENDED COST OF DEBT IN THIS CASE?

A. Based on what this Commission allowed Western Carolina University in its 2016 rate case, as well as the above-stated recent costs for utility debt, I believe a reasonable cost of debt for use in this case is 4.23%. This cost of debt is the same allowed by this Commission in the 2016 Western Carolina University rate case and it is within 0.01% of the average of the current published cost of debt as summarized in Table 3 above.

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 4 below.

Table 4: NRLP Recommended Overall Cost of Capital

Capitalization Component	Ratio	Cost	Weighted Cost
Long-Term Debt	50%	4.23%	2.12%
Common Equity	50%	9.70%	4.85%
			6.97%

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-3.

Q: WHAT IS THE PURPOSE OF AN ALLOCATED COST OF SERVICE ANALYSIS?

A: An allocated cost of service analysis is one tool used by utility managers to determine the level of rates required for each rate class to recover the costs of providing service. 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 thus based on reasonable judgment of the analyst in developing the study. Other factors must be considered before changing rates which could include comparison of rates to other utilities in the area, impact of rate changes on customers, sending price signals to change customers' habits and determining the complexity of the rate design.

Q: PLEASE DESCRIBE HOW YOU DEVELOPED THE ALLOCATED COST OF SERVICE ANALYSIS.

A: The allocated cost of service analysis was based on the total system revenue requirements as provided by ASU's Witness Sheree Brown. I allocated each component of the revenue requirement by cost-causative factors which included demand, energy, number of customers and weighted customers.

- Customer Specific – This allocation would be used to assign 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 develop an allocation factor for expense items related to the variable nature of consuming energy.
- NCP Demand – NCP load factors (LF) were estimated for each customer class (except Commercial Demand High LF, ASU Campus & Security Lighting) by taking the annual NCP LF of the wholesale delivery point that most closely matched the usage pattern of the respective customer class. Commercial Demand High LF NCP demand is based on actual billing data. ASU NCP demand is based on the actual NCP demand from the ASU substation. Security Lighting was estimated by assuming 12 hours of lamp burn time per day. This factor is used to allocate expense items related to the distribution of energy.
- CP Demand – CP LF were estimated for each customer class (except Commercial Demand High LF, ASU Campus & Security Lighting) by taking the average CP LF of the wholesale delivery point that most closely matched the usage pattern of the respective customer class. Commercial Demand High LF CP demand was based on an assumed coincident factor for large general service customers applied to the class NCP. ASU Campus demand was

the actual CP demand from the ASU substation. Security Lighting is assumed at 50% of its NCP to ensure some fixed demand costs are appropriately assigned. This factor is used to allocate wholesale purchase power demand and transmission expenses.

- 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 explained by ASU's Witness, Sheree Brown, the overall revenue requirement is $18,709,918. This revenue requirement already includes an offset of $104,181 for Other Operating Revenues.

Q: **WHAT ARE THE TOTAL REVENUES AT PRESENT RATES?**

A: Present rates consist of base rates, a Purchase Power Adjustment Clause ("PPAC"), and Other Operating Revenues, such as miscellaneous service charges. The present base and PPAC rates provide revenues of $16,835,531. Other operating revenues provide an additional $104,181, which have already been incorporated as a reduction to the revenue requirement.

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Q: HOW DID YOU DETERMINE THE REVENUES UNDER CURRENT RATES?

A: Revenues for the 2016 historical Test Year were provided by NRLP as shown in the 2016 financial statements. It was necessary to adjust the reported 2016 Test Year revenues to account for the PPAC rate adjustments that were effective February 1, 2017. The actual billing determinants for the 2016 Test Year were applied to NRLP's current rates to provide current rate revenues to compare against the cost of service revenue requirements.

Q: COULD NRLP EXPECT ADDITIONAL REVENUES IN THE RATE YEAR DUE TO THE PPAC?

A: Yes. Each year, NRLP updates its PPAC to reflect the current estimated cost of purchased power. Given the expected cost of power, a PPAC adjustment of $298,693 is expected if no change in base rates is made.

It should be noted that in June 2017, NRLP has received a notice of true up to the 2016 purchased power costs from Blue Ridge. This notice indicated that NRLP was underbilled by $203,645.04 for 2016. NRLP will pay this true up this year and will recoup this cost from its customers through the PPAC. This amount was not included as a revenue requirement to capture through base rates.

Q: WOULD THE INCREASE IN THE PPAC REVENUES CAUSE AN INCREASE IN OTHER EXPENSES?

A: Yes. The increase in revenue would increase the regulatory commission fee and uncollectible accounts by $756, resulting in an overall reduction to revenues required from other sources of $297,937 ($298,693-$756).

Q: WHAT IS THE TOTAL REVENUE DEFICIENCY AT PRESENT RATES?

A: Comparing the revenue requirement to the revenues at present rates, including the expected increase in net PPAC revenues indicates a revenue deficiency of $1,583,445 as summarized in Table 5.

Table 5: Revenue Deficiency

Description	Amount ($)
Revenue Requirement (including Offset for Current Other Operating Revenues)	$18,709,918
Less Revenue from Sales:	
Current Rates and PPAC	$16,835,581
Additional Net PPAC Revenue	$297,937
Total Revenue from Sales	$17,133,519
Revenue Deficiency	$1,576,399

The revenue increase in base rates and PPAC needed to cover this deficiency must first be offset by any additional changes expected in miscellaneous service charges. As shown below, I am recommending changes to miscellaneous service charges that will produce an extra $119,304 in revenue; therefore, the net revenue deficiency to be recovered from base rates and the PPAC is $1,457,095. When compared to present rates of $17,133,519 (including the expected PPAC adjustment), this is an overall system revenue increase of 8.50%.

Q: **WHAT ASSUMPTION DID YOU MAKE REGARDING ADDITIONAL MISCELLANEOUS SERVICE REVENUES AND THE PPAC IN DETERMINING THE REVENUE REQUIREMENT TO BE RECOVERED THROUGH BASE RATES?**

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A: I assumed that the revenue requirement would be offset by the $119,304 in additional miscellaneous service charges and that the total purchased power costs would be "rolled into" base rates. This results in a total net revenue requirement of $18,590,614 ($18,709,918 - $119,304) that was allocated to each customer class.

Q: PLEASE DESCRIBE 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 detail analysis is included as Exhibit_(REH-3). Table 6 summarizes the result of the costs of service analysis.

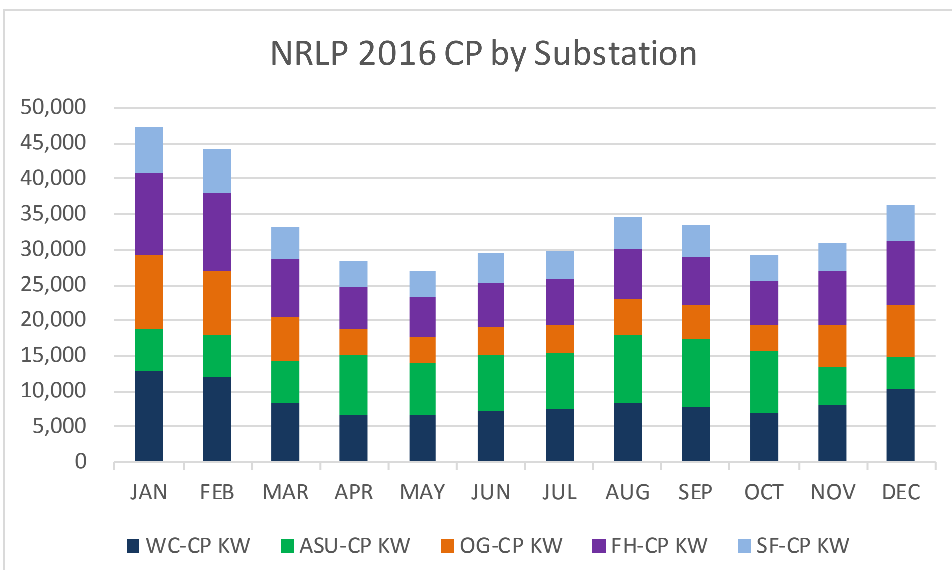
Table 6: Summary of Cost of Service Analysis

Class	Total Revenue Requirement	Total Current Rates	Revenue Deficiency
Total System	$18,590,614	$16,835,581	$1,755,033
Residential	$6,025,027	$5,133,268	$891,759
Commercial Non-Demand	$2,320,397	$2,128,008	$192,389
Commercial Demand	$4,718,662	$4,113,885	$604,777
Commercial Demand High LF	$1,381,283	$1,253,370	$127,912
ASU Campus	$3,803,004	$3,863,382	$(60,378)
Security Lighting	$342,241	$343,668	$(1,427)

It should be noted that these revenue deficiencies include the required increase to cover the full estimated cost of purchased power, including the increase that would otherwise have been realized through the PPAC.

Q: WHY IS ASU CAMPUS SHOWING A DECREASE WHEN THE OTHER RATE CLASSES ARE RECEIVING INCREASES?

A: ASU is currently on an energy only retail rate and as such the purchased power and transmission costs have been charged on an energy only basis. If you examine the load characteristics of the ASU Campus, you'll see that it is summer peaking while contributing very little to the NRLP total system annual winter peak. The graph below summarizes the 2016 CP kW demands for each of NRLP's substations. You'll see that during the annual CP in January, the ASU Campus contributed the least to this peak. The CP allocation factor used in the cost of service analysis has assigned an appropriate percentage of purchased power demand and transmission costs to the ASU Campus. The ASU Campus is currently subsidizing these costs for the other customer classes.



Q: DOES THE PROPOSED RATE DESIGN ADJUST THE TOTAL REVENUES TO COLLECT FROM EACH CUSTOMER CLASS CONSISTANT WITH THE COST OF SERVICE FINDINGS?

A: Yes. The Rate Design model is included as Exhibit_REH-4.

Q: ARE THERE ANY PROPOSED RATE STRUCTURE MODIFCATIONS WITHIN EACH CUSTOMER CLASS?

A: Yes. The following will summarize the rate structure modifications:

- Purchased Power Costs – The total cost of purchased power is included in base rates and allocated to each customer class. There are no proposed costs to be collected through the PPAC. The PPAC would be adjusted as needed in the future. As stated earlier, NRLP received a 2016 true up from Blue Ridge for an underbilled amount of $203,645 that will be collected from customers through the PPAC. This amount has not been included in base rates or this analysis.
- Residential Service – To assist NRLP in recovering more of its fixed costs through fixed customer charges, we are proposing to increase the Basic Facilities Charge from $6.29 to $12.58. The cost of service analysis identified an average monthly cost per customer of $17.81 for all customer related expenses. When comparing what neighboring utilities Blue Ridge and Duke Energy Carolinas (DEC) charge for a monthly customer charge, $24.17 and 11.80, respectively, limiting this increase to $12.58 was reasonable. The remaining allocated revenue requirements would be recovered through the energy rate totaling an increase in revenue of $891,745.
- Commercial Non-Demand - To assist NRLP in recovering more of its fixed costs through fixed customer charges, we are proposing to

increase the Basic Facilities Charge from \$8.71 to \$17.42. The cost of service analysis identified an average monthly cost per customer of \$20.39 for all customer related expenses. When comparing what neighboring utilities Blue Ridge and DEC charge for a monthly customer charge, \$24.17 and 19.39, respectively, limiting this increase to \$17.42 was reasonable. The remaining allocated revenue requirements would be recovered through the energy rate totaling an increase in revenue of \$192,390.

- Commercial Demand Service - To assist NRLP in recovering more of its fixed costs through fixed customer charges, we are proposing to increase the Basic Facilities Charge from \$11.61 to \$23.22. The cost of service analysis identified an average monthly cost per customer of \$98.75 for all customer related expenses. When comparing what neighboring utilities Blue Ridge and DEC charge for a monthly customer charge, \$24.17 and 19.39, respectively, limiting this increase to \$23.22 was reasonable. The demand rate of \$8.27 per kW was unchanged based on a comparison of demand rates from Blue Ridge and DEC ranging from \$3.86 to \$6.15. The remaining allocated costs would be recovered through the energy rate totaling an increase in revenue of \$604,760.
- Commercial Demand High Load Factor Service – This is a proposed new rate class designed to provide the appropriate price signal to those commercial customers with load factors at or above the NRLP system average load factor of 65%. To determine which customers qualified for this rate class, actual kw and kWh billing data for 2016 was analyzed for all Commercial Demand Customers. Based on this analysis, 18 customers fit this criterion and their actual kw and kWh billing data were used in developing this rate structure. The Basic Facilities Charge would be \$23.22,

the demand rate would be $10.00 per kW and the remaining allocated costs would be recovered through the energy rate totaling an increase in revenue of $127,912 as compared to the current Commercial Demand Service rate.

- ASU Campus Service – To insure all distribution facility/customer specific costs for the ASU Campus are recovered and a pricing structure is established to assist ASU with its sustainability efforts, a master meter structure is proposed for the ASU Campus load. The ASU Campus load is served solely from one substation and the energy metered at this substation would be used for billing purposes. NRLP would still own and maintain the distribution facilities throughout the campus. Based on the cost of service analysis, NRLP's cost of owning and maintaining these facilities as well as ASU's portion of A&G and customer service costs are $888,362. The proposed rate structure would charge $8.89 per NCP kW demand as currently measured at the ASU substation to recover these costs. The revenue from this charge would be $888,654.

  The remaining costs to recover are NRLP's purchased power costs attributed to ASU. These would be recovered through an $8.75 charge per NCP demand and the remaining through the energy charge. These three charges described above would result in a decrease in revenue of $60,353 as compared to ASU's current energy only rate.

  As part of ASU's sustainability efforts, they continually look for ways to be more efficient with their energy consumption as well as the potential addition of renewable generation. These proposed rate changes would allow ASU to continue these efforts with the appropriate price signals of true avoided costs. It would also allow

NRLP to recover its true costs of delivering electric service to ASU.

Q: ARE THERE ANY OTHER PROPOSED CHANGES TO RATES OR FEES?

A: Yes. The following will summarize the proposed changes to other rates and fees:

- Connect Charge – NRLP currently charges $3.00 for connection service. After reviewing their cost to conduct this service, we are proposing an increase to $11.50.
- Returned Payment Fee – This is a new service fee proposed at $21.00 to recover NRLP's cost of working through the process of a returned payment.
- Late Fee – NRLP does not currently charge a fee for customers paying late. This is a proposed fee of $5.00 to encourage customers to pay the electric bills on time.
- Delinquent Fee – NRLP does not currently have a fee to recoup additional costs incurred when pass due notices are required to be sent out. This proposed fee would be applied once a customer is 45 days past due on the bill. The proposed fee is $15.00.
- LED Security Lighting – NRLP will be moving toward LED security lighting and phasing out the use of the existing mercury-vapor, sodium-vapor and metal halide lights. A new LED security lighting rate schedule is proposed for this process to begin. Exhibit_(REH-5) includes the cost components used in determining the appropriate monthly fee for the various LED light types.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

Testi

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Discounted Cash Flow Results

Company Name	13-Week Dividend Yield	4-Week Dividend Yield	1-Week Dividend Yield	Average Dividend Yield	Value Line Growth Rate	Schwab Growth Rate	Thomson Growth Rate	Average Growth Rate	DCF Result
Dominion Energy	4.0%	4.1%	4.1%	4.1%	5.5%	4.0%	4.0%	4.5%	8.6%
Duke Energy Corp New	4.2%	4.2%	4.2%	4.2%	4.5%	2.6%	2.6%	3.2%	7.5%
NextEra Energy Inc	2.9%	2.9%	2.9%	2.9%	6.5%	6.2%	6.2%	6.3%	9.2%
SCANA Corporation	3.7%	3.7%	3.9%	3.8%	4.0%	5.6%	5.6%	5.1%	8.8%
Southern Co	4.7%	4.9%	5.0%	4.9%	3.5%	4.2%	4.0%	3.9%	8.8%

Average	**8.6%**
Median	**8.8%**

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Comparable Earnings

Company Name	Earned Returns on Common Equity			
	2016	2017E	2018E	20-22E
Dominion Energy	14.5%	13.5%	15.0%	19.0%
Duke Energy Corp New	6.2%	8.0%	8.0%	8.5%
NextEra Energy Inc	11.1%	12.5%	13.0%	13.0%
SCANA Corporation	10.4%	10.0%	10.0%	10.0%
Southern Co	11.0%	11.5%	11.5%	12.0%
Average	10.6%	11.1%	11.5%	12.5%

Average ROE 2017 - 2022	**11.7%**
Median ROE 2017 - 2022	**11.5%**

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2016

Line	Description	Allocation Factors	Total System	Residential	Commercial Non-Demand	Commercial Demand	Comm Demand High LF >65%	ASU Campus	Security Lighting
			Allocation Factors						
	SPECIFIC ALLOCATOR:								
1.01	Residential	c	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
1.02	Commercial Non-Demand	c	1.000000	0.000000	1.000000	0.000000	0.000000	0.000000	0.000000
1.03	Commercial Demand	c	1.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
1.04	Commercial Demand High Load Factor	c	1.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
1.05	ASU Campus	c	1.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
1.06	Security Lighting	c	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
	ENERGY ALLOCATOR:								
	Usage in kWh		202,215,273	53,270,063	23,797,508	53,826,414	19,733,160	48,094,075	3,494,053
2.01	Allocation %	e	100.00%	26.34%	11.77%	26.62%	9.76%	23.78%	1.73%
	Res. And Commercial Usage Only		150,627,145	53,270,063	23,797,508	53,826,414	19,733,160		
2.02	Allocation %	e	100.00%	35.37%	15.80%	35.73%	13.10%		
	DEMAND ALLOCATORS	*Load Factor*	*47.19%*	*37.18%*	*46.91%*	*46.91%*	*71.83%*	*56.40%*	*50.00%*
	Annual NCP Demand (kW) [1]		48,915	16,357	5,791	13,098	3,136	9,735	798
3.01	Allocation %	d	100.00%	33.44%	11.84%	26.78%	6.41%	19.90%	1.63%
		Load Factor	*75.40%*	*69.82%*	*72.75%*	*72.75%*	*95.46%*	*78.83%*	*n/a*
	Average CP Demand (kW) [2]		30,614	8,710	3,734	8,446	2,360	6,964	399
3.02	Allocation %	d	100.00%	28.45%	12.20%	27.59%	7.71%	22.75%	1.30%
	CUSTOMER ALLOCATORS:								
	Average Number of Customers		8,148	6,188	1,494	251	18	107	90
4.01	Allocation %	c	100.00%	75.94%	18.34%	3.07%	0.22%	1.32%	1.11%
4.02	Weighted Customer/Energy/NCP Demand Allocation [3]	c	100.00%	42.29%	13.45%	20.81%	5.70%	16.23%	1.52%
4.03	Weighted Customer/NCP Demand Allocation [4]	c	100.00%	44.07%	13.46%	20.85%	4.86%	15.26%	1.50%
4.04	Number of Customers Excluding Security Lighting Allocation %	c	100.00%	76.80%	18.54%	3.11%	0.22%	1.33%	

Notes:

[1] NCP Load Factors (LF) were estimated for each customer class (except Comm Demand High LF & Security Lighting) by taking the annual NCP LF of the wholesale delivery point that most closely matched the usage pattern of the respective customer class. Comm Demand High LF is based on actual billing data. Security Lighting was estimated by assuming 12 hours of lamp burn time per day.

[2] CP Load Factors (LF) were estimated for each customer class (except Comm Demand High LF & Security Lighting) by taking the average CP LF of the wholesale delivery point that most closely matched the usage pattern of the respective customer class. Comm Demand High LF demand was based on a DEP coincident factor for large general service customers applied to he NCP. Security Lighting is assumed at 50% of its NCP to ensure some fixed demand costs are appropriately assigned.

[3] 4.02 - Weighted Customer Allocation:

NCP Demand	50.00%
Customer	25.00%
Energy	25.00%
Total	100.00%

[4] 4.03 - Weighted Customer Allocation:

NCP Demand	75.00%
Customer	25.00%
Total	100.00%

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2016

Line	Description		Allocation Factors	Total System	Residential	Commercial Non-Demand	Commercial Demand	Comm Demand High LF >65%	ASU Campus	Security Lighting
	Current Rate Revenues									
1.01	Energy Charges			$ 14,017,770	$ 4,666,191	$ 1,971,838	$ 2,583,991	$ 947,310	$ 3,848,440	$ -
1.02	Demand Charges			$ 1,798,571	$ -	$ -	$ 1,494,995	$ 303,576	$ -	$ -
1.03	Customer Charges			$ 1,019,241	$ 467,077	$ 156,170	$ 34,900	$ 2,485	$ 14,942	$ 343,668
1.04	**Total Revenues from Current Rates**			**$ 16,835,581**	**$ 5,133,268**	**$ 2,128,008**	**$ 4,113,885**	**$ 1,253,370**	**$ 3,863,382**	**$ 343,668**
REV1	Total Revenue Allocator			100.00%	30.49%	12.64%	24.44%	7.44%	22.95%	2.04%
REV2	Total Revenue Allocator Excluding ASU			100.00%	39.57%	16.40%	31.71%	9.66%	0.00%	2.65%
	Other Operating Income									
2.00	Revenue Job & Contract ASU	c	4.04	$ 23,777	$ 18,260	$ 4,409	$ 739	$ 53	$ 316	$ -
2.01	Rev Job&Con TOB	c	4.04	$ 6,824	$ 5,241	$ 1,265	$ 212	$ 15	$ 91	$ -
2.02	Revenue Job & Contract Cmp Broadstone	c	4.04	$ 509	$ 391	$ 94	$ 16	$ 1	$ 7	$ -
2.03	Int Inc Other	c	4.04	$ 9,831	$ 7,550	$ 1,823	$ 306	$ 22	$ 131	$ -
2.04	Misc Non-Operating Income	c	4.04	$ 51	$ 39	$ 10	$ 2	$ 0	$ 1	$ -
2.05	Misc Svc Revenue-Conn & Reconnect Chrgs	c	Direct	$ 129,949	$ 97,462	$ 16,244	$ 16,244	$ -	$ -	$ -
2.06	Temporary Construct Revenue	c	4.04	$ 21,974	$ 16,875	$ 4,075	$ 683	$ 49	$ 292	$ -
2.07	Rent Electric Property	c	4.04	$ 24,569	$ 18,868	$ 4,556	$ 764	$ 54	$ 327	$ -
2.08	Rent Electric Property-Fiber	c	4.04	$ 6,000	$ 4,608	$ 1,113	$ 187	$ 13	$ 80	$ -
2.09	Total Other Operating Income		Sum	$ 223,485	$ 169,294	$ 33,588	$ 19,151	$ 207	$ 1,245	$ -
3.00	**Total Revenues**		Sum	$ 17,059,067	$ 5,302,561	$ 2,161,596	$ 4,133,037	$ 1,253,577	$ 3,864,627	$ 343,668
	Purchased Power									
4.00	Energy Expense	e	2.01	$ 4,893,995	$ 1,289,237	$ 575,945	$ 1,302,702	$ 477,580	$ 1,163,968	$ 84,563
4.01	Demand Expense	d	3.02	$ 6,243,456	$ 1,776,341	$ 761,584	$ 1,722,590	$ 481,267	$ 1,420,328	$ 81,345
4.02	Transmission & Ancillary Expenses	d	3.02	$ 521,183	$ 148,283	$ 63,575	$ 143,796	$ 40,175	$ 118,564	$ 6,790
4.03	BREMCO Distribution Expenses	d	3.02	$ 1,257,246	$ 357,702	$ 153,360	$ 346,878	$ 96,913	$ 286,012	$ 16,380
4.04	Generation Credit	c	1.05	$ (74,340)	$ -	$ -	$ -	$ -	$ (74,340)	$ -
4.05	Avioded Costs for Retail Customer Renewable Energy	c	4.04	$ 8,238	$ 6,327	$ 1,528	$ 256	$ 18	$ 110	$ -
4.06	Total Purchased Power Expense		Sum	$ 12,849,778	$ 3,577,890	$ 1,555,992	$ 3,516,223	$ 1,095,953	$ 2,914,642	$ 189,079
	Total Purchased Power Expense			**$ 12,849,778**	**$ 3,577,890**	**$ 1,555,992**	**$ 3,516,223**	**$ 1,095,953**	**$ 2,914,642**	**$ 189,079**
	Customer-Related	**c**		$ (66,102)	$ 6,327	$ 1,528	$ 256	$ 18	$ (74,230)	$ -
	Energy-Related	**e**		$ 4,893,995	$ 1,289,237	$ 575,945	$ 1,302,702	$ 477,580	$ 1,163,968	$ 84,563
	Demand-Related	**d**		$ 8,021,884	$ 2,282,326	$ 978,519	$ 2,213,265	$ 618,354	$ 1,824,904	$ 104,516
	Gross Income									
5.00	Revenues less Purchased Power		Sum	$ 4,209,289	$ 1,724,671	$ 605,604	$ 616,814	$ 157,625	$ 949,985	$ 154,590

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2016

Line	Description		Allocation Factors	Total System	Residential	Commercial Non-Demand	Commercial Demand	Comm Demand High LF >65%	ASU Campus	Security Lighting
	Electric Operating & Maintenance Expenses									
	Expense Job & Contract ASU									
6.00	Expense Job & Contract ASU	c	4.04	$ 3,652	$ 2,805	$ 677	$ 114	$ 8	$ 49	$ -
6.01	Expense Job & Contract ASU-Labor	c	4.04	$ 9,512	$ 7,304	$ 1,764	$ 296	$ 21	$ 127	$ -
6.02	Expense Job & Contract ASU-Benefits	c	4.04	$ 9,609	$ 7,380	$ 1,782	$ 299	$ 21	$ 128	$ -
6.03	Expense Job & Contract ASU-Transportation	c	4.04	$ 1,401	$ 1,076	$ 260	$ 44	$ 3	$ 19	$ -
6.04	Expense Job & Contract TOB-Labor	c	4.04	$ 3,356	$ 2,577	$ 622	$ 104	$ 7	$ 45	$ -
6.05	Expense Job & Contract TOB-Benefits	c	4.04	$ 1,824	$ 1,401	$ 338	$ 57	$ 4	$ 24	$ -
6.06	Expense Job & Contract TOB-Transportation	c	4.04	$ 595	$ 457	$ 110	$ 18	$ 1	$ 8	$ -
6.07	Expense Job & Contract Camp Broadstone	c	4.04	$ 219	$ 168	$ 41	$ 7	$ 0	$ 3	$ -
6.08	Expense Job & Contract Camp Broadstone-Benefits	c	4.04	$ 107	$ 82	$ 20	$ 3	$ 0	$ 1	$ -
6.09	Expense Job & Contract Camp Broadstone-Transportation	c	4.04	$ 71	$ 54	$ 13	$ 2	$ 0	$ 1	$ -
6.10	Total Expense Job & Contract ASU		Sum	$ 30,344	$ 23,303	$ 5,627	$ 943	$ 67	$ 404	$ -
	Operations Superv & Engineering									
7.00	Operations Superv & Engineering-Labor	c	4.03	$ 119,980	$ 52,870	$ 16,153	$ 25,018	$ 5,835	$ 18,303	$ 1,800
7.01	Operations Superv & Engineering-Benefits	c	4.03	$ 42,250	$ 18,618	$ 5,688	$ 8,810	$ 2,055	$ 6,445	$ 634
7.02	Operations Superv & Engineering-Transportation	c	4.03	$ 2,977	$ 1,312	$ 401	$ 621	$ 145	$ 454	$ 45
7.03	Total Operations Superv & Engineering		Sum	$ 165,207	$ 72,800	$ 22,243	$ 34,449	$ 8,034	$ 25,203	$ 2,479
	Station Expense									
8.00	Station Expense-Labor	d	3.01	$ 6,930	$ 2,317	$ 820	$ 1,856	$ 444	$ 1,379	$ 113
8.01	Station Expense-Benefits	d	3.01	$ 3,674	$ 1,229	$ 435	$ 984	$ 236	$ 731	$ 60
8.02	Station Expense-Transportation	d	3.01	$ 823	$ 275	$ 97	$ 220	$ 53	$ 164	$ 13
8.03	Total Station Expense		Sum	$ 11,427	$ 3,821	$ 1,353	$ 3,060	$ 733	$ 2,274	$ 186
9.00	Overhead Line Expense	c	4.03	$ 1,722	$ 759	$ 232	$ 359	$ 84	$ 263	$ 26
	Meter Expense									
10.00	Meter Expense	c	4.04	$ 30,326	$ 23,289	$ 5,623	$ 943	$ 67	$ 404	$ -
10.01	Meter Expense-Labor	c	4.04	$ 18,728	$ 14,382	$ 3,473	$ 582	$ 41	$ 249	$ -
10.02	Meter Expense-Benefits	c	4.04	$ 11,527	$ 8,852	$ 2,137	$ 358	$ 26	$ 153	$ -
10.03	Meter Expense-Transportation	c	4.04	$ 2,500	$ 1,920	$ 464	$ 78	$ 6	$ 33	$ -
10.04	Total Meter Expense		Sum	$ 63,082	$ 48,444	$ 11,697	$ 1,961	$ 140	$ 840	$ -
	Customer Install Expense									
11.00	Customer Install Expense-Labor	c	4.01	$ 6,930	$ 5,263	$ 1,271	$ 213	$ 15	$ 91	$ 77
11.01	Customer Install Expense-Benefits	c	4.01	$ 3,674	$ 2,790	$ 674	$ 113	$ 8	$ 48	$ 41
11.02	Customer Install Expense-Transportation	c	4.01	$ 823	$ 625	$ 151	$ 25	$ 2	$ 11	$ 9
11.03	Total Customer Install Expense		Sum	$ 11,427	$ 8,678	$ 2,095	$ 351	$ 25	$ 150	$ 127

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2016

Line	Description		Allocation Factors	Total System	Residential	Commercial Non-Demand	Commercial Demand	Comm Demand High LF >65%	ASU Campus	Security Lighting
	Miscellaneous Distribution Expense									
12.00	Miscellaneous Distribution Expense	d	3.01	$ 11,139	$ 3,725	$ 1,319	$ 2,983	$ 714	$ 2,217	$ 182
12.01	Miscellaneous Distribution Expense-Labor	d	3.01	$ 151,872	$ 50,786	$ 17,980	$ 40,668	$ 9,736	$ 30,225	$ 2,477
12.02	Miscellaneous Distribution Expense-Benefits	d	3.01	$ 86,879	$ 29,052	$ 10,285	$ 23,264	$ 5,570	$ 17,290	$ 1,417
12.03	Total Miscellaneous Distribution Expense		Sum	$ 249,890	$ 83,563	$ 29,584	$ 66,914	$ 16,020	$ 49,733	$ 4,075
	Maintenance Superv & Engineering									
13.00	Maintenance Superv & Engineering-Labor	c	4.03	$ 31,881	$ 14,049	$ 4,292	$ 6,648	$ 1,550	$ 4,864	$ 478
13.01	Maintenance Superv & Engineering-Benefits	c	4.03	$ 17,281	$ 7,615	$ 2,327	$ 3,603	$ 840	$ 2,636	$ 259
13.02	Maintenance Superv & Engineering-Transportation	c	4.03	$ 3,791	$ 1,671	$ 510	$ 790	$ 184	$ 578	$ 57
13.03	Total Maintenance Superv & Engineering		Sum	$ 52,953	$ 23,334	$ 7,129	$ 11,042	$ 2,575	$ 8,078	$ 795
	On Call Pay									
14.00	On Call Pay -Primary/Secondary	c	4.03	$ 28,782	$ 12,683	$ 3,875	$ 6,001	$ 1,400	$ 4,391	$ 432
14.01	On Call Pay-Primary/Secondary Benefits	c	4.03	$ 20,337	$ 8,962	$ 2,738	$ 4,241	$ 989	$ 3,102	$ 305
14.02	Total On Call Pay		Sum	$ 49,118	$ 21,644	$ 6,613	$ 10,242	$ 2,389	$ 7,493	$ 737
	Maintenance Station Equipment									
15.00	Maintenance Station Equipment	d	3.01	$ 1,387	$ 464	$ 164	$ 371	$ 89	$ 276	$ 23
15.01	Maintenance Station Equipment-Labor	d	3.01	$ 16,606	$ 5,553	$ 1,966	$ 4,447	$ 1,065	$ 3,305	$ 271
15.02	Maintenance Station Equipment-Benefits	d	3.01	$ 14,463	$ 4,837	$ 1,712	$ 3,873	$ 927	$ 2,878	$ 236
15.03	Maintenance Station Equipment-Transportation	d	3.01	$ 1,681	$ 562	$ 199	$ 450	$ 108	$ 335	$ 27
15.04	Total Maintenance Station Equipment		Sum	$ 34,137	$ 11,415	$ 4,041	$ 9,141	$ 2,189	$ 6,794	$ 557
	Maintenance Overhead Lines									
16.00	Maintenance Overhead Lines	d	3.01	$ 157,519	$ 52,675	$ 18,648	$ 42,180	$ 10,098	$ 31,349	$ 2,569
16.01	Maintenance Overhead Lines-Labor	d	3.01	$ 114,174	$ 38,180	$ 13,517	$ 30,573	$ 7,320	$ 22,723	$ 1,862
16.02	Maintenance Overhead Lines-Benefits	d	3.01	$ 64,744	$ 21,651	$ 7,665	$ 17,337	$ 4,151	$ 12,885	$ 1,056
16.03	Maintenance Overhead Lines-Transportation	d	3.01	$ 12,907	$ 4,316	$ 1,528	$ 3,456	$ 827	$ 2,569	$ 210
16.04	Total Maintenance Overhead Lines		Sum	$ 349,345	$ 116,821	$ 41,358	$ 93,546	$ 22,396	$ 69,526	$ 5,697
	Maintenance Underground Lines									
17.00	Maintenance Underground Lines	c	4.03	$ 6,218	$ 2,740	$ 837	$ 1,296	$ 302	$ 949	$ 93
17.01	Maintenance Underground Lines-Labor	c	4.03	$ 18,618	$ 8,204	$ 2,507	$ 3,882	$ 905	$ 2,840	$ 279
17.02	Maintenance Underground Lines-Benefits	c	4.03	$ 14,396	$ 6,344	$ 1,938	$ 3,002	$ 700	$ 2,196	$ 216
17.03	Maintenance Underground Lines-Transportation	c	4.03	$ 1,988	$ 876	$ 268	$ 415	$ 97	$ 303	$ 30
17.04	Total Maintenance Underground Lines		Sum	$ 41,220	$ 18,164	$ 5,550	$ 8,595	$ 2,004	$ 6,288	$ 619
	Maintenance Line Transformers									
18.00	Maintenance Line Transformers	c	4.03	$ 16,119	$ 7,103	$ 2,170	$ 3,361	$ 784	$ 2,459	$ 242
18.01	Maintenance Line Transformers-Labor	c	4.03	$ 783	$ 345	$ 105	$ 163	$ 38	$ 119	$ 12
18.02	Maintenance Line Transformers-Benefits	c	4.03	$ (511)	$ (225)	$ (69)	$ (107)	$ (25)	$ (78)	$ (8)
18.03	Maintenance Line Transformers-Transportation	c	4.03	$ 61	$ 27	$ 8	$ 13	$ 3	$ 9	$ 1
18.04	Total Maintenance Line Transformers		Sum	$ 16,452	$ 7,250	$ 2,215	$ 3,430	$ 800	$ 2,510	$ 247

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2016

Line	Description		Allocation Factors	Total System	Residential	Commercial Non-Demand	Commercial Demand	Comm Demand High LF >65%	ASU Campus	Security Lighting
	Maintenance Street Lights									
19.00	Maintenance Street Lights	c	1.06	$ 16,179	$ -	$ -	$ -	$ -	$ -	$ 16,179
19.01	Maintenance Street Lights-Labor	c	1.06	$ 17,761	$ -	$ -	$ -	$ -	$ -	$ 17,761
19.02	Maintenance Street Lights-Benefits	c	1.06	$ 8,363	$ -	$ -	$ -	$ -	$ -	$ 8,363
19.03	Maintenance Street Lights-Transportation	c	1.06	$ 2,375	$ -	$ -	$ -	$ -	$ -	$ 2,375
19.04	Total Maintenance Street Lights		Sum	$ 44,677	$ -	$ -	$ -	$ -	$ -	$ 44,677
	Maintenance-Meters									
20.00	Maintenance-Meters	c	4.04	$ 6,431	$ 4,939	$ 1,192	$ 200	$ 14	$ 86	$ -
20.01	Maintenance-Meters-Labor	c	4.04	$ 52,485	$ 40,306	$ 9,732	$ 1,632	$ 116	$ 699	$ -
20.02	Maintenance-Meters-Benefits	c	4.04	$ 30,227	$ 23,213	$ 5,605	$ 940	$ 67	$ 402	$ -
20.03	Maintenance-Meters-Transportation	c	4.04	$ 5,451	$ 4,186	$ 1,011	$ 169	$ 12	$ 73	$ -
20.04	Total Maintenance-Meters		Sum	$ 94,594	$ 72,644	$ 17,541	$ 2,941	$ 209	$ 1,259	$ -
	Maintenance Misc Distribution Plant									
21.00	Maintenance Misc Distribution Plant	c	4.03	$ 681	$ 300	$ 92	$ 142	$ 33	$ 104	$ 10
21.01	Maintenance Misc Distribution Plant-Labor	c	4.03	$ 56,862	$ 25,057	$ 7,656	$ 11,857	$ 2,765	$ 8,675	$ 853
21.02	Maintenance Misc Distribution Plant-Benefits	c	4.03	$ 15,618	$ 6,882	$ 2,103	$ 3,257	$ 760	$ 2,383	$ 234
21.03	Maintenance Misc Distribution Plant-Transportation	c	4.03	$ 5,985	$ 2,637	$ 806	$ 1,248	$ 291	$ 913	$ 90
21.04	Total Maintenance Misc Distribution Plant		Sum	$ 79,146	$ 34,876	$ 10,656	$ 16,503	$ 3,849	$ 12,074	$ 1,188
	Supervision Customer Accounts									
22.00	Supervision Customer Accounts-Labor	c	4.01	$ 30,858	$ 23,434	$ 5,658	$ 949	$ 68	$ 406	$ 342
22.01	Supervision Customer Accounts-Benefits	c	4.01	$ 16,768	$ 12,734	$ 3,075	$ 516	$ 37	$ 221	$ 186
22.02	Supervision Customer Accounts-Transportation	c	4.01	$ 3,681	$ 2,796	$ 675	$ 113	$ 8	$ 48	$ 41
22.03	Total Supervision Customer Accounts		Sum	$ 51,307	$ 38,965	$ 9,408	$ 1,577	$ 112	$ 675	$ 569
	Meter Reading Expense									
23.00	Meter Reading Expense	c	4.01	$ 1,455	$ 1,105	$ 267	$ 45	$ 3	$ 19	$ 16
23.01	Meter Reading Expense-Labor	c	4.01	$ 20,742	$ 15,752	$ 3,804	$ 638	$ 45	$ 273	$ 230
23.02	Meter Reading Expense-Benefits	c	4.01	$ 11,790	$ 8,954	$ 2,162	$ 362	$ 26	$ 155	$ 131
23.03	Meter Reading Expense-Transportation	c	4.01	$ 2,238	$ 1,699	$ 410	$ 69	$ 5	$ 29	$ 25
23.04	Total Meter Reading Expense		Sum	$ 36,225	$ 27,510	$ 6,643	$ 1,114	$ 79	$ 477	$ 402
	Customer Records									
24.00	Customer Records & Collections Expense	c	4.01	$ 144,195	$ 109,507	$ 26,441	$ 4,433	$ 316	$ 1,898	$ 1,600
24.01	Customer Records & Collections Expense-Labor	c	4.01	$ 173,671	$ 131,892	$ 31,846	$ 5,339	$ 380	$ 2,286	$ 1,927
24.02	Customer Records & Collections Expense-Benefits	c	4.01	$ 94,798	$ 71,993	$ 17,383	$ 2,914	$ 207	$ 1,248	$ 1,052
24.03	Postage	c	4.01	$ 4,976	$ 3,779	$ 913	$ 153	$ 11	$ 66	$ 55
24.04	Customer Records Cash Over/Short	c	4.01	$ 13	$ 10	$ 2	$ 0	$ 0	$ 0	$ 0
24.05	Customer Records - Bank Service Fees	c	4.01	$ 17,908	$ 13,600	$ 3,284	$ 551	$ 39	$ 236	$ 199
24.06	Customer Records - Credit Card Fees	c	4.01	$ 35,612	$ 27,045	$ 6,530	$ 1,095	$ 78	$ 469	$ 395
24.07	Total Customer Records		Sum	$ 471,173	$ 357,826	$ 86,400	$ 14,485	$ 1,031	$ 6,202	$ 5,228

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2016

Line	Description	Allocation Factors		Total System	Residential	Commercial Non-Demand	Commercial Demand	Comm Demand High LF >65%	ASU Campus	Security Lighting
	Maintenance Of General Plant									
25.00	Maintenance Of General Plant	c	4.03	$ 69,681	$ 30,706	$ 9,381	$ 14,530	$ 3,389	$ 10,630	$ 1,046
25.01	Maintenance Of General Plant-Labor	c	4.03	$ 2,284	$ 1,007	$ 308	$ 476	$ 111	$ 348	$ 34
25.02	Maintenance Of General Plant-Benefits	c	4.03	$ 1,109	$ 489	$ 149	$ 231	$ 54	$ 169	$ 17
25.03	Maintenance Of General Plant-Transportation	c	4.03	$ 149	$ 66	$ 20	$ 31	$ 7	$ 23	$ 2
25.04	Total Maintenance Of General Plant		Sum	$ 73,224	$ 32,267	$ 9,858	$ 15,268	$ 3,561	$ 11,171	$ 1,099
26.00	Subtotal Electric Operating & Maintenance Expense			$ 14,776,448	$ 4,581,976	$ 1,836,235	$ 3,812,145	$ 1,162,250	$ 3,126,056	$ 257,786
26.01	Subtotal Electric O&M Excluding Purchased Power			$ 1,926,670	$ 1,004,086	$ 280,243	$ 295,923	$ 66,297	$ 211,414	$ 68,708
26.02	**Electric O&M Excluding Purchased Power Allocator**	w		100.00%	52.12%	14.55%	15.36%	3.44%	10.97%	3.57%
	Electric O&M Excluding Purchased Power			**$ 1,926,670**	**$ 1,004,086**	**$ 280,243**	**$ 295,923**	**$ 66,297**	**$ 211,414**	**$ 68,708**
	Customer-Related	**c**		$ 1,281,871	$ 788,465	$ 203,906	$ 123,261	$ 24,959	$ 83,087	$ 58,192
	Energy-Related	**e**		$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Demand-Related	**d**		$ 644,799	$ 215,621	$ 76,336	$ 172,661	$ 41,338	$ 128,327	$ 10,516
	General & Administrative Expenses									
	Administration - Other									
27.00	Customer Assistance Expense	w	26.02	$ 3,379	$ 1,761	$ 492	$ 519	$ 116	$ 371	$ 121
27.01	Informational Advertising Expense	w	26.02	$ 4,572	$ 2,383	$ 665	$ 702	$ 157	$ 502	$ 163
27.02	Administrative & General-Salaries	w	26.02	$ 306,658	$ 159,815	$ 44,605	$ 47,100	$ 10,552	$ 33,650	$ 10,936
27.03	Administrative & General-Benefits	w	26.02	$ 152,137	$ 79,287	$ 22,129	$ 23,367	$ 5,235	$ 16,694	$ 5,425
27.04	Office Supplies And Expenses	w	26.02	$ 26,862	$ 13,999	$ 3,907	$ 4,126	$ 924	$ 2,948	$ 958
27.05	Consulting Fees	w	26.02	$ 97,087	$ 50,597	$ 14,122	$ 14,912	$ 3,341	$ 10,653	$ 3,462
27.06	Investment Management Expense	w	26.02	$ 23,888	$ 12,449	$ 3,475	$ 3,669	$ 822	$ 2,621	$ 852
27.07	Property Insurance	w	26.02	$ 6,190	$ 3,226	$ 900	$ 951	$ 213	$ 679	$ 221
27.08	Injuries & Damages Expense	w	26.02	$ 67,740	$ 35,303	$ 9,853	$ 10,404	$ 2,331	$ 7,433	$ 2,416
27.09	Injuries & Damages Expense-Labor	w	26.02	$ 5,905	$ 3,078	$ 859	$ 907	$ 203	$ 648	$ 211
27.10	Injuries & Damages Expense-Benefits	w	26.02	$ 3,354	$ 1,748	$ 488	$ 515	$ 115	$ 368	$ 120
27.11	Injuries & Damages Expense-Transporation	w	26.02	$ 829	$ 432	$ 121	$ 127	$ 29	$ 91	$ 30
27.12	Institutional Advertising Expense	w	26.02	$ 10,457	$ 5,450	$ 1,521	$ 1,606	$ 360	$ 1,147	$ 373
27.13	Miscellaneous General Expense	w	26.02	$ 53,958	$ 28,120	$ 7,848	$ 8,288	$ 1,857	$ 5,921	$ 1,924
27.14	Total Administrative-Other		Sum	$ 763,017	$ 397,647	$ 110,984	$ 117,194	$ 26,256	$ 83,726	$ 27,210
	ASU Administrative Support Costs									
28.00	Legal	w	26.02	$ 106,501	$ 55,503	$ 15,491	$ 16,358	$ 3,665	$ 11,686	$ 3,798
28.01	Human Resources	w	26.02	$ 17,351	$ 9,042	$ 2,524	$ 2,665	$ 597	$ 1,904	$ 619
28.02	Information Technology	w	26.02	$ 16,788	$ 8,749	$ 2,442	$ 2,579	$ 578	$ 1,842	$ 599
28.03	Administrative Supervision	w	26.02	$ 60,940	$ 31,759	$ 8,864	$ 9,360	$ 2,097	$ 6,687	$ 2,173
28.04	Total ASU Administrative Support Costs		Sum	$ 201,580	$ 105,054	$ 29,321	$ 30,961	$ 6,936	$ 22,119	$ 7,189

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2016

Line	Description		Allocation Factors	Total System	Residential	Commercial Non-Demand	Commercial Demand	Comm Demand High LF >65%	ASU Campus	Security Lighting
	Increase in Salary and Benefits									
29.00	A&G Related	w	26.02	$ 29,531	$ 15,390	$ 4,295	$ 4,536	$ 1,016	$ 3,240	$ 1,053
29.01	Customer Service Related	c	4.01	$ 18,823	$ 14,295	$ 3,452	$ 579	$ 41	$ 248	$ 209
29.02	Distribution Related	c	4.03	$ 32,943	$ 14,517	$ 4,435	$ 6,869	$ 1,602	$ 5,026	$ 494
29.03	Contract Related	c	4.04	$ 903	$ 693	$ 167	$ 28	$ 2	$ 12	$ -
29.04	Total Increase in Salary and Benefits		Sum	$ 82,200	$ 44,895	$ 12,350	$ 12,012	$ 2,661	$ 8,526	$ 1,756
30.00	**Total O&M**		Sum	$ 15,823,245	$ 5,129,572	$ 1,988,889	$ 3,972,312	$ 1,198,103	$ 3,240,427	$ 293,942
30.01	Total O&M Allocator			100.00%	32.42%	12.57%	25.10%	7.57%	20.48%	1.86%
30.02	Total O&M Less Purchased Power		Sum	$ 2,973,467	$ 1,551,682	$ 432,898	$ 456,089	$ 102,150	$ 325,785	$ 104,863
30.03	Total O&M Less Purchased Power Allocator			100.00%	52.18%	14.56%	15.34%	3.44%	10.96%	3.53%
	Total O&M Excluding Purchased Power			**$ 2,973,467**	**$ 1,551,682**	**$ 432,898**	**$ 456,089**	**$ 102,150**	**$ 325,785**	**$ 104,863**
	Customer-Related	**c**		$ 1,995,963	$ 1,224,804	$ 317,173	$ 194,338	$ 39,483	$ 131,244	$ 88,921
	Energy-Related	**e**		$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Demand-Related	**d**		$ 977,504	$ 326,878	$ 115,725	$ 261,752	$ 62,667	$ 194,542	$ 15,942
	Depreciation and Property Transaction Expense									
31.00	Depreciation	d	3.01	$ 1,007,854	$ 337,027	$ 119,318	$ 269,879	$ 64,613	$ 200,582	$ 16,437
31.01	Amortization of Regulatory Asset and Gain on Old Trucks	d	3.01	$ 43,958	$ 14,700	$ 5,204	$ 11,771	$ 2,818	$ 8,749	$ 717
31.02	Gain/Loss Disposing Utility Property	d	3.01	$ 3,376	$ 1,129	$ 400	$ 904	$ 216	$ 672	$ 55
31.03	Sale Of Surplus Property	d	3.01	$ (850)	$ (284)	$ (101)	$ (228)	$ (55)	$ (169)	$ (14)
31.04	Total Depreciation and Property Transaction Expense		Sum	$ 1,054,338	$ 352,571	$ 124,821	$ 282,326	$ 67,593	$ 209,833	$ 17,195
	Interest Expense									
	Interest Expense:									
32.00	Interest Expense Consumer Deposits	c	4.01	$ 12,933	$ 9,822	$ 2,372	$ 398	$ 28	$ 170	$ 144
32.01	Total Interest Expense		Sum	$ 12,933	$ 9,822	$ 2,372	$ 398	$ 28	$ 170	$ 144
	Total Expenses									
33.00	Total Expenses			$ 16,890,516	$ 5,491,965	$ 2,116,082	$ 4,255,035	$ 1,265,724	$ 3,450,430	$ 311,280
33.01	Total Expenses Less Purchased Power			$ 4,040,738	$ 1,914,075	$ 560,090	$ 738,813	$ 169,771	$ 535,788	$ 122,201
	Total Expenses			**$ 16,890,516**	**$ 5,491,965**	**$ 2,116,082**	**$ 4,255,035**	**$ 1,265,724**	**$ 3,450,430**	**$ 311,280**
	Customer-Related	**c**		$ 1,942,794	$ 1,240,953	$ 321,072	$ 194,991	$ 39,530	$ 57,183	$ 89,065
	Energy-Related	**e**		$ 4,893,995	$ 1,289,237	$ 575,945	$ 1,302,702	$ 477,580	$ 1,163,968	$ 84,563
	Demand-Related	**d**		$ 10,053,727	$ 2,961,775	$ 1,219,064	$ 2,757,342	$ 748,615	$ 2,229,279	$ 137,652
	Total Expenses Less Purchased Power			**$ 4,040,738**	**$ 1,914,075**	**$ 560,090**	**$ 738,813**	**$ 169,771**	**$ 535,788**	**$ 122,201**
	Customer-Related	**c**		$ 2,008,896	$ 1,234,626	$ 319,545	$ 194,735	$ 39,511	$ 131,414	$ 89,065
	Energy-Related	**e**		$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Demand-Related	**d**		$ 2,031,842	$ 679,449	$ 240,545	$ 544,078	$ 130,260	$ 404,374	$ 33,136

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Cost of Service Analysis
For Twelve Months Ended December 31, 2016

Line	Description		Allocation Factors	Total System	Residential	Commercial Non-Demand	Commercial Demand	Comm Demand High LF >65%	ASU Campus	Security Lighting
	Net Income and Return on Rate Base									
34.00	Net Income		Sum	$ 168,550	$ (189,404)	$ 45,514	$ (121,999)	$ (12,147)	$ 414,196	$ 32,389
	Rate Base									
35.00	Plant In Service	d	3.01	$ 30,620,715	$ 10,239,581	$ 3,625,118	$ 8,199,475	$ 1,963,074	$ 6,094,091	$ 499,375
35.01	Less: Accumulated Depreciation	d	3.01	$ (12,263,250)	$ (4,100,836)	$ (1,451,819)	$ (3,283,797)	$ (786,189)	$ (2,440,615)	$ (199,994)
35.02	Net Plant in Service		Sum	$ 18,357,465	$ 6,138,745	$ 2,173,299	$ 4,915,678	$ 1,176,885	$ 3,653,477	$ 299,381
35.03	Construction Work in Progress	d	3.01	$ 62,292	$ 20,831	$ 7,375	$ 16,680	$ 3,994	$ 12,397	$ 1,016
35.04	Investments - Blue Ridge Electric Membership Corporation	c	4.03	$ 6,973,506	$ 3,072,942	$ 938,871	$ 1,454,097	$ 339,116	$ 1,063,840	$ 104,640
35.05	Investments - North Carolina Electric Membership Corporation	c	4.03	$ 407,837	$ 179,717	$ 54,909	$ 85,041	$ 19,833	$ 62,217	$ 6,120
35.06	Regulatory Asset (Unamortized Old Meters)	c	4.01	$ 139,708	$ 106,100	$ 25,619	$ 4,295	$ 306	$ 1,839	$ 1,550
35.07	Regulatory Asset (Hydro Removal and Clean-up)	d	3.02	$ 52,500	$ 14,937	$ 6,404	$ 14,485	$ 4,047	$ 11,943	$ 684
35.08	Regulatory Liabililty on Gain from Old Trucks	d	3.01	$ 18,792	$ 6,284	$ 2,225	$ 5,032	$ 1,205	$ 3,740	$ 306
35.09	Prepayments	d	3.01	$ 34,573	$ 11,561	$ 4,093	$ 9,258	$ 2,216	$ 6,881	$ 564
35.10	Working Capital	d	3.01	$ 890,924	$ 297,925	$ 105,474	$ 238,568	$ 57,117	$ 177,310	$ 14,530
35.11	**Total Rate Base**		Sum	**$ 26,937,598**	**$ 9,849,042**	**$ 3,318,268**	**$ 6,743,134**	**$ 1,604,717**	**$ 4,993,645**	**$ 428,791**
35.12	**Current Return on Rate Base**		Calc	**0.63%**	**-1.92%**	**1.37%**	**-1.81%**	**-0.76%**	**8.29%**	**7.55%**
36.00	**Proposed Return on Rate Base**		Pulled	**6.97%**	**6.97%**	**6.97%**	**6.97%**	**6.97%**	**6.97%**	**6.97%**
36.01	Targeted Net Income		Calc	$ 1,876,204	$ 685,986	$ 231,117	$ 469,659	$ 111,769	$ 347,807	$ 29,865
36.02	**Revenue Requirement before Uncollectible Accounts Adder**		Sum	**$ 18,543,235**	**$ 6,008,657**	**$ 2,313,611**	**$ 4,705,543**	**$ 1,377,286**	**$ 3,796,993**	**$ 341,145**
36.03	Additional Revenue Requirement to Cover Uncollectible Accounts	**c**	REV2	$ 21,185.20	$ 8,383	$ 3,475	$ 6,718	$ 2,047	$ -	$ 561
36.04	Additional Revenue Requirement to Cover Regulatory Commission Expense	**c**	REV1	$ 26,193.89	$ 7,987	$ 3,311	$ 6,401	$ 1,950	$ 6,011	$ 535
36.05	**Total Revenue Requirement to Recover from Rates**		Sum	**$ 18,590,614**	**$ 6,025,027**	**$ 2,320,397**	**$ 4,718,662**	**$ 1,381,283**	**$ 3,803,004**	**$ 342,241**
36.06	Total Current Rate Revenues		Pulled	$ 16,835,581	$ 5,133,268	$ 2,128,008	$ 4,113,885	$ 1,253,370	$ 3,863,382	$ 343,668
36.07	**Total Revenue Increase(Decrease) Required**		Sum	**$ 1,755,033**	**$ 891,759**	**$ 192,389**	**$ 604,777**	**$ 127,912**	**$ (60,378)**	**$ (1,427)**
36.08	**Total Percent Increase(Decrease) Required**		Calc	**10.42%**	**17.37%**	**9.04%**	**14.70%**	**10.21%**	**-1.56%**	**-0.42%**
36.09	*Current Base Rate Revenues*		*Pulled*	*$ 13,806,599*	*$ 4,335,335*	*$ 1,771,545*	*$ 3,307,619*	*$ 957,787*	*$ 3,142,981*	*$ 291,331*
36.10	*Base Revenue Increase(Decrease) Required*		*Sum*	*$ 4,784,015*	*$ 1,689,692*	*$ 548,852*	*$ 1,411,043*	*$ 423,495*	*$ 660,023*	*$ 50,910*
36.11	*Base Percent Increase(Decrease) Required*		*Calc*	*34.65%*	*38.97%*	*30.98%*	*42.66%*	*44.22%*	*21.00%*	*17.48%*
	Total Revenue Requirement to Recover from Rates			**$ 18,543,235**	**$ 6,008,657**	**$ 2,313,611**	**$ 4,705,543**	**$ 1,377,286**	**$ 3,796,993**	**$ 341,145**
	Customer-Related	**c**		$ 2,243,150	$ 1,305,597	$ 358,485	$ 283,340	$ 64,345	$ 134,496	$ 96,887
	Energy-Related	**e**		$ 4,893,995	$ 1,289,237	$ 575,945	$ 1,302,702	$ 477,580	$ 1,163,968	$ 84,563
	Demand-Related	**d**		$ 11,406,089	$ 3,413,823	$ 1,379,181	$ 3,119,501	$ 835,361	$ 2,498,528	$ 159,695
	Rev Req to Recover from Rates Adj. for Uncollectible Accounts & Reg. Fee			**$ 18,590,614**	**$ 6,025,027**	**$ 2,320,397**	**$ 4,718,662**	**$ 1,381,283**	**$ 3,803,004**	**$ 342,241**
	Customer-Related	**c**		$ 2,290,529	$ 1,321,967	$ 365,271	$ 296,459	$ 68,342	$ 140,507	$ 97,983
	Energy-Related	**e**		$ 4,893,995	$ 1,289,237	$ 575,945	$ 1,302,702	$ 477,580	$ 1,163,968	$ 84,563
	Demand-Related	**d**		$ 11,406,089	$ 3,413,823	$ 1,379,181	$ 3,119,501	$ 835,361	$ 2,498,528	$ 159,695

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Current and Proposed Rate Design
For Twelve Months Ended December 31, 2016

Line	Description	Billing Determinants	Current Rates	Current Rate Revenues	Proposed Rates	Proposed Revenue	Increase (Decrease)	Percent Increase
1	**Residential Service:**							
2	Basic Facilities Charge	6,188	$ 6.29	$ 467,077	$ 12.58	$ 934,153	$ 467,077	100.00%
3	Energy Charge:							
4	Base Energy - All kWh	53,270,063	$ 0.072616	$ 3,868,259	$ 0.095567	$ 5,090,860	$ 1,222,601	31.61%
5	PPA Energy - All kWh		$ 0.014979	$ 797,932	$ -	$ -	$ (797,932)	-100.00%
6	Total Energy - All kWh		$ 0.087595	$ 4,666,191	$ 0.095567	$ 5,090,860	$ 424,669	9.10%
7	***Total Residential Service***			***$ 5,133,268***		***$ 6,025,013***	***$ 891,745***	***17.37%***
8	**Commercial Non-Demand Service:**							
9	Basic Facilities Charge	1,494	$ 8.71	$ 156,170	$ 17.42	$ 312,341	$ 156,170	100.00%
10	Energy Charge:							
11	Base Energy - All kWh	23,797,508	$ 0.067880	$ 1,615,375	$ 0.084381	$ 2,008,058	$ 392,683	24.31%
12	PPA Energy - All kWh		$ 0.014979	$ 356,463	$ -	$ -	$ (356,463)	-100.00%
13	Total Energy - All kWh		$ 0.082859	$ 1,971,838	$ 0.084381	$ 2,008,058	$ 36,220	1.84%
14	***Total Commercial Non-Demand Service***			***$ 2,128,008***		***$ 2,320,398***	***$ 192,390***	***9.04%***
15	**Commercial Demand Service:**							
16	Basic Facilities Charge	251	$ 11.61	$ 34,900	$ 23.22	$ 69,799	$ 34,900	100.00%
17	Demand Charge:							
18	All kW	180,773	$ 8.27	$ 1,494,995	$ 8.27	$ 1,494,995	$ -	0.00%
19	Energy Charge:							
20	Base Energy - All kWh	53,826,414	$ 0.033027	$ 1,777,725	$ 0.058593	$ 3,153,851	$ 1,376,126	77.41%
21	PPA Energy - All kWh		$ 0.014979	$ 806,266	$ -	$ -	$ (806,266)	-100.00%
22	Total Energy - All kWh		$ 0.048006	$ 2,583,991	$ 0.058593	$ 3,153,851	$ 569,860	22.05%
23	***Total Commercial Demand Service***			***$ 4,113,885***		***$ 4,718,645***	***$ 604,760***	***14.70%***
24	**Commercial Demand High Load Factor Service:**							
25	Basic Facilities Charge	18	$ 11.61	$ 2,485	$ 23.22	$ 4,969	$ 2,485	100.00%
26	Demand Charge:							
27	All kW	36,708	$ 8.27	$ 303,576	$ 10.00	$ 367,081	$ 63,505	20.92%
28	Energy Charge:							
29	Base Energy - All kWh	19,733,160	$ 0.033027	$ 651,727	$ 0.051144	$ 1,009,233	$ 357,506	54.86%
30	PPA Energy - All kWh		$ 0.014979	$ 295,583	$ -	$ -	$ (295,583)	-100.00%
31	Total Energy - All kWh		$ 0.048006	$ 947,310	$ 0.051144	$ 1,009,233	**$ 61,923**	6.54%
32	***Total Commercial Demand High Load Factor Service***			***$ 1,253,370***		***$ 1,381,283***	***$ 127,912***	***10.21%***

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Current and Proposed Rate Design
For Twelve Months Ended December 31, 2016

Line	Description	Billing Determinants	Current Rates	Current Rate Revenues	Proposed Rates	Proposed Revenue	Increase (Decrease)	Percent Increase
33	**ASU Service:**		*Current Structure*		*Master Meter Structure*			
34	Basic Facilities Charge (Meters at Customer Premises)	107	$ 11.61	$ 14,942				
35	Distribution Facilities Charge (NCP at ASU Substation)	99,961			*$ 8.89*	$ 888,654		
36	Demand Charge:							
37	All kW (NCP at Customer Premises)	95,837	$ -	$ -				
38	All kW (NCP at ASU Substation)	99,961			*$ 8.75*	$ 874,659		
39	Energy Charge:							
40	All kWh (at Customer Premises)	48,094,075						
41	All kWh (at ASU Substation)	50,163,918						
42	Base Energy Charge - All kWh		$ 0.065040	$ 3,128,039	*$ 0.040661*	$ 2,039,715		
43	PPA Energy Charge - All kWh		$ 0.014979	$ 720,401	*$ -*	$ -		
44	Total Energy Charge - All kWh		$ 0.080019	$ 3,848,440	*$ 0.040661*	$ 2,039,715		
45	***Total ASU Service***			***$ 3,863,382***		***$ 3,803,029***	***$ (60,353)***	**-1.56%**
46	**Security Lighting:**							
47	*Base Charge*							
48	175 Watt MV	242	$ 7.82	$ 22,720	$ 8.95	$ 25,991	$ 3,271	14.40%
49	400 Watt MV	5	$ 13.92	$ 835	$ 16.40	$ 984	$ 149	17.79%
50	150 Watt SV	146	$ 7.55	$ 13,228	$ 8.60	$ 15,067	$ 1,839	13.90%
51	250 Watt SV	434	$ 10.93	$ 56,900	$ 12.50	$ 65,100	$ 8,200	14.41%
52	400 Watt MH	423	$ 16.40	$ 83,263	$ 18.88	$ 95,835	$ 12,572	15.10%
53	250 Watt MH	243	$ 13.24	$ 38,594	$ 14.81	$ 43,186	$ 4,592	11.90%
54	100 Watt SV TOB	2	$ 2.26	$ 54	$ 2.81	$ 67	$ 13	24.16%
55	150 Watt SV TOB	89	$ 3.19	$ 3,407	$ 4.24	$ 4,528	$ 1,121	32.90%
56	175 Watt MV TOB	301	$ 3.82	$ 13,811	$ 4.95	$ 17,879	$ 4,068	29.45%
57	250 Watt SV TOB	173	$ 5.49	$ 11,388	$ 7.06	$ 14,657	$ 3,269	28.71%
58	400 Watt MV TOB	11	$ 8.81	$ 1,163	$ 11.29	$ 1,490	$ 327	28.10%
59	400 Watt SV TOB	429	$ 8.81	$ 45,371	$ 11.29	$ 58,121	$ 12,750	28.10%
60	750 Watt SV TOB	3	$ 16.54	$ 595	$ 21.18	$ 762	$ 167	28.07%
61	*PPA Charge*							
62	175 Watt MV		$ 1.13	$ 3,271	$ -	$ -	$ (3,271)	-100.00%
63	400 Watt MV		$ 2.48	$ 149	$ -	$ -	$ (149)	-100.00%
64	150 Watt SV		$ 1.05	$ 1,839	$ -	$ -	$ (1,839)	-100.00%
65	250 Watt SV		$ 1.57	$ 8,200	$ -	$ -	$ (8,200)	-100.00%
66	400 Watt MH		$ 2.48	$ 12,572	$ -	$ -	$ (12,572)	-100.00%
67	250 Watt MH		$ 1.57	$ 4,592	$ -	$ -	$ (4,592)	-100.00%

Assumptions for Master Meter Structure:

1. The **Distribution Facilities Charge** recovers all fixed customer and distribution facility costs associated with ASU.
2. The **Demand and Energy Charges** recover all purchased power related costs associated with ASU.

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Current and Proposed Rate Design
For Twelve Months Ended December 31, 2016

Line	Description	Billing Determinants	Current Rates	Current Rate Revenues	Proposed Rates	Proposed Revenue	Increase (Decrease)	Percent Increase
68	100 Watt SV TOB		$ 0.55	$ 13	$ -	$ -	$ (13)	-100.00%
69	150 Watt SV TOB		$ 1.05	$ 1,121	$ -	$ -	$ (1,121)	-100.00%
70	175 Watt MV TOB		$ 1.13	$ 4,068	$ -	$ -	$ (4,068)	-100.00%
71	250 Watt SV TOB		$ 1.57	$ 3,269	$ -	$ -	$ (3,269)	-100.00%
72	400 Watt MV TOB		$ 2.48	$ 327	$ -	$ -	$ (327)	-100.00%
73	400 Watt SV TOB		$ 2.48	$ 12,750	$ -	$ -	$ (12,750)	-100.00%
74	750 Watt SV TOB		$ 4.64	$ 167	$ -	$ -	$ (167)	-100.00%
75	*Total Charge*							
76	175 Watt MV		$ 8.95	$ 25,991	$ 8.95	$ 25,991	$ -	0.00%
77	400 Watt MV		$ 16.40	$ 984	$ 16.40	$ 984	$ -	0.00%
78	150 Watt SV		$ 8.60	$ 15,067	$ 8.60	$ 15,067	$ -	0.00%
79	250 Watt SV		$ 12.50	$ 65,100	$ 12.50	$ 65,100	$ -	0.00%
80	400 Watt MH		$ 18.88	$ 95,835	$ 18.88	$ 95,835	$ -	0.00%
81	250 Watt MH		$ 14.81	$ 43,186	$ 14.81	$ 43,186	$ -	0.00%
82	100 Watt SV TOB		$ 2.81	$ 67	$ 2.81	$ 67	$ -	0.00%
83	150 Watt SV TOB		$ 4.24	$ 4,528	$ 4.24	$ 4,528	$ -	0.00%
84	175 Watt MV TOB		$ 4.95	$ 17,879	$ 4.95	$ 17,879	$ -	0.00%
85	250 Watt SV TOB		$ 7.06	$ 14,657	$ 7.06	$ 14,657	$ -	0.00%
86	400 Watt MV TOB		$ 11.29	$ 1,490	$ 11.29	$ 1,490	$ -	0.00%
87	400 Watt SV TOB		$ 11.29	$ 58,121	$ 11.29	$ 58,121	$ -	0.00%
88	750 Watt SV TOB		$ 21.18	$ 762	$ 21.18	$ 762	$ -	0.00%
89	Estimated kWh Usage	3,494,053						
90	***Total Security Lighting***			***$ 343,668***		***$ 343,668***	***$ -***	**0.00%**
91	**Total System:**							
92	**Total Customers (Excluding Security Lighting)**	**8,058**						
93	**Total kWh Usage**	**202,215,273**						
94	**Total Base Revenues**			**$ 13,806,599**		**$ 18,592,036**	**$ 4,785,437**	**34.66%**
95	**Total PPA Revenues**			**$ 3,028,983**		**$ -**	**$ (3,028,983)**	**-100.00%**
96	**Total Revenues**			**$ 16,835,581**		**$ 18,592,036**	**$ 1,756,454**	**10.43%**
97	*Facilities Charge*			*$ 1,019,241*		*$ 2,553,584*	*$ 1,534,343*	*150.54%*
98	*Demand Charge*			*$ 1,798,571*		*$ 2,736,735*	*$ 938,164*	*52.16%*
99	*Energy Charge*			*$ 14,017,770*		*$ 13,301,716*	*$ (716,053)*	*-5.11%*

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Proposed Monthly Charges for New LED Lighting

Line	Light and Pole Costs	Cost			Life	ROR	Monthly Cost
		Material	Installation	Total			
1	Monthly Light Costs:						
2	100 Watt Yard Light	$ 133.44	$ 160.94	$ 294.38	20	6.97%	$2.28
3	150 Watt Flood Light	$ 571.59	$ 160.94	$ 732.53	20	6.97%	$5.66
4	266 Watt Flood Light	$ 806.80	$ 160.94	$ 967.74	20	6.97%	$7.48
5	162 Watt Cobra Head	$ 583.35	$ 160.94	$ 744.29	20	6.97%	$5.75
6	Monthly Pole Cost:						
7	30' Wood Pole	$ 122.38	$ 413.88	$ 536.26	30	6.97%	$3.56
8	Decorative Fiberglass Pole	$ 659.96	$ 413.88	$ 1,073.84	30	6.97%	$7.12

Line	O&M Costs	Watts	Daily Burn (Hrs)	Monthly kWh	O&M Cost / kWh	Monthly O&M Cost
9	Monthly O&M Costs:					
10	100 Watt Yard Light	100	12	37	$ 0.03001	$ 1.11
11	150 Watt Flood Light	150	12	55	$ 0.03001	$ 1.65
12	266 Watt Flood Light	266	12	97	$ 0.03001	$ 2.91
13	162 Watt Cobra Head	162	12	59	$ 0.03001	$ 1.77

Line	Purchased Power Costs	Watts	Daily Burn (Hrs)	Monthly kWh	PP Cost / kWh	Monthly PP Cost
14	Monthly Purchased Power Costs:					
15	100 Watt Yard Light	100	12	37	$ 0.05411	$ 2.00
16	150 Watt Flood Light	150	12	55	$ 0.05411	$ 2.98
17	266 Watt Flood Light	266	12	97	$ 0.05411	$ 5.25
18	162 Watt Cobra Head	162	12	59	$ 0.05411	$ 3.19

Docket No. E-34, Sub 46
Appalachian State University
d/b/a New River Light and Power Company
Proposed Monthly Charges for New LED Lighting

	Monthly Light and Pole Charges	Monthly Charge	Costs Included			
			Light Cost	Pole Cost	O&M Cost	Purchased Power Cost
19	Metered Lighting Only:					
20	100 Watt Yard Light	$3.39	X		X	
21	150 Watt Flood Light	$7.31	X		X	
22	266 Watt Flood Light	$10.39	X		X	
23	162 Watt Cobra Head	$7.53	X		X	
24	Metered Lighting with Wood Pole:					
25	100 Watt Yard Light	$6.94	X	X	X	
26	150 Watt Flood Light	$10.87	X	X	X	
27	266 Watt Flood Light	$13.95	X	X	X	
28	162 Watt Cobra Head	$11.08	X	X	X	
29	Metered Lighting with Decorative Fiberglass Pole:					
30	100 Watt Yard Light	$10.51	X	X	X	
31	150 Watt Flood Light	$14.43	X	X	X	
32	266 Watt Flood Light	$17.51	X	X	X	
33	162 Watt Cobra Head	$14.64	X	X	X	
34	Unmetered Lighting Only:					
35	100 Watt Yard Light	$5.39	X		X	X
36	150 Watt Flood Light	$10.29	X		X	X
37	266 Watt Flood Light	$15.64	X		X	X
38	162 Watt Cobra Head	$10.72	X		X	X
39	Unmetered Lighting with Wood Pole:					
40	100 Watt Yard Light	$8.94	X	X	X	X
41	150 Watt Flood Light	$13.85	X	X	X	X
42	266 Watt Flood Light	$19.20	X	X	X	X
43	162 Watt Cobra Head	$14.27	X	X	X	X
44	Unmetered Lighting with Decorative Fiberglass Pole:					
45	100 Watt Yard Light	$12.51	X	X	X	X
46	150 Watt Flood Light	$17.41	X	X	X	X
47	266 Watt Flood Light	$22.76	X	X	X	X
48	162 Watt Cobra Head	$17.84	X	X	X	X

STATE OF FLORIDA)
)
)
)
Orange COUNTY)

VERIFICATION

Docket No. E-34, Sub 46

PERSONALLY APPEARED before me, Randall E. Halley who, after first being duly sworn, said that he is a Managing Principal with Summit Utility Advisors, Inc. and, as such, is authorized to make this verification; that he has read the foregoing Direct Testimony and knows the contents thereof; and that the same is true and accurate to the best of his knowledge, information and belief.

RANDALL E. HALLEY

Sworn to and subscribed before me,
this the 26 day of July, 2017.

, Notary Public

My Commission Expires:

Notary Public State of Florida
Elsie Torres
My Commission FF 951726
Expires 02/15/2020