BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-34, SUB 54
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	)	
In the Matter of Application for General Rate Case	)	
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DOCKET NO. E-34, SUB 55	)	**POST-HEARING BRIEF OF APPALACHIAN VOICES**
	)	
In the Matter of Petition of Appalachian State University d/b/a New River Light and Power for an Accounting Order to Defer Certain Capital Costs and New Tax Expenses	)	

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1. Introduction

New Right Light and Power's (NRLP) rates must be based on its actual costs, "predicated on adequate factual findings." *State ex rel. Utilities Comm'n v. Cooper*, 366 N.C. 484, 491, 739 S.E.2d 541, 546 (2013). Neither the rates that NRLP proposed on its own nor the rates proposed in its stipulation and settlement agreement with the Public Staff meet that standard, and the North Carolina Utilities Commission (Commission or NCUC) should decline to approve them for that reason. As described below, NRLP's proposed rate of return is excessive and untethered to the utility's cost of capital. Similarly, the supplemental fixed charge that NRLP has proposed imposing on rooftop solar customers who take service under its new net-billing schedule is based on a calculation that artificially capped the costs that customer-sited solar allows NRLP to avoid. And the rapidly escalating fixed charge that NRLP has proposed assessing all customers does not represent the actual costs that NRLP incurs to serve the marginal customer in each class. Finally, concerning some costs already incurred, NRLP's customers have not seen the full value of the investment NRLP has made in modern metering and control systems, and it is past time for NRLP to propose proper energy efficiency and demand-side management programs.

It has been a theme in this proceeding that NRLP is an unusual utility because it is the subsidiary of a not-for-profit institution owned by the State of North Carolina, and NRLP's unusual status has been intertwined with the determination of NRLP's actual costs. In general, NRLP has used its status as an excuse; for example, effectively taking the position that it is too hard to determine NRLP's actual costs, so the Commission should allow NRLP to piggyback on the rates of return earned by dissimilar gas distribution utilities. Tr. vol. 4, 291-292 (Wit. Halley, acknowledging basis for comparison, despite major differences, is being distribution-only utilities regulated by the Commission); Tr. vol. 2, 74-76 (Wit. Hoyle explaining issue). But this is backwards; NRLP's rates and programs should lead the state. Unfortunately, it will take the Commission's guidance to get there, but residents of Boone deserve no less.

2. NRLP's proposed rate of return is excessive.

New River's cost of capital proposals, along with the Public Staff's cost of capital proposals and the cost of capital proposals set forth in the Agreement and Stipulation of Settlement between New River and the Public Staff (the Stipulation), purport to (1) set New River's return on equity (ROE), cost of debt, and capital structure consistent with the Due Process clause and (2) result in just and reasonable rates. However, they fail to adhere to state and federal ratemaking standards, and in doing so fail to properly account for New River's nonprofit status and incorporate New River's actual costs. As such, the Commission should reject the Stipulation, adopt Appalachian Voices' (App Voices) cost of capital proposals, and require New River to (1) conduct a discounted cash flow (DCF) analysis to better optimize its capital structure and (2) submit a compliance filing that reflects this analysis and any revised cost of capital figures that flow therefrom.

A. Federal and state legal ratemaking standards tie a utility's rate of return to its actual costs.

Under Chapter 62, "the General Assembly conferred [on the North Carolina Utilities Commission (Commission or NCUC)] 'broad powers to regulate public utilities and to compel their operation in accordance with the policy of the State....'" *State ex rel. Utils. Comm'n v. Carolina Water Serv., Inc. of N.C.*, 225 N.C. App. 120, 133–34, 738 S.E.2d 187, 196 (2013) (quoting *State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n*, 123 N.C. App. 623, 625, 473 S.E.2d 661, 663 (1996)).

Among other things, the Commission is charged under Chapter 62 with determining the proper rate of return, which refers to the funds, represented by a percentage, necessary to compensate lenders and shareholders for helping utilities finance their infrastructure investments. Under N.C. Gen. Stat. § 62-133(b)(4), determining the rate of return entails the following:

> Fix[ing] such rate of return on the cost of the property ascertained pursuant to subdivision (1) of this subsection as will enable the public utility by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, including, but not limited to, the inclusion of construction work in progress in the utility's property under sub-subdivision b. of subdivision (1) of this subsection, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors.

As a threshold issue though, the Commission must first determine "the *reasonable original cost* or the fair value under G.S. 62-133.1A of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State" also referred to as rate base, to which the rate of return will ultimately be applied. N.C. Gen. Stat. § 62-133(b)(1). As expounded upon in *Cooper*, 366 N.C. 484, 739 S.E.2d 541, N.C. Gen. Stat. § 62-133(b)(4) also requires the Commission to "make [specific] findings of fact regarding the impact of changing economic conditions on customers" when determining ROE. *Cooper*, 366 N.C. at 494, 739 S.E.2d at 547.

At bottom, "[t]he origin of this statute supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of" the Due Process Clauses of the state and federal constitutions. *State ex rel. Utils. Comm'n v. Duke Power Co.*, 285 N.C. 377, 388, 206 S.E.2d 269, 276–77 (1974) (citing *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 600-05 (1944) (*Hope*)). The Constitution does not bind the Commission "to the service of any single formula or combination of formulas." *Fed. Power Comm'n v. Nat. Gas Pipeline Co. of Am.*, 315 U.S. 575, 586 (1942). Instead, setting the rate of return is "essentially a matter of judgment based on a number of factual considerations which vary from case to case." *State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n*, 322 N.C. 689, 697, 370 S.E.2d 567, 572 (1988).

With respect to the return on equity (ROE) component of a utility's required rate of return, *Hope*, consistent with the Due Process clause, requires that the ROE "be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Hope,* 320 U.S. at 603. Similarly, *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923) dictates the following:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Id. at 692-93.

The cost of debt component of the rate of return should typically be set to reflect the embedded cost or average cost of long-term debt, which is calculated by dividing a utility's total annual interest expense on its long-term debt issuances by the average of its outstanding long-term debt. *See, e.g.*, *State ex rel. Utilities Comm'n v. Mebane Home Tel. Co.*, 298 N.C. 162, 166, 257 S.E.2d 623, 627 (1979); *see also* JIM LAZAR, REGULATORY ASSISTANCE PROJECT, ELECTRICITY REGULATION IN THE US: A GUIDE 56-57 (2nd ed. 2016) ("The cost of debt is the **average cost** of the utility's borrowed funds for the test year." (alteration in original)). Similarly, the capital structure component of the rate of return is typically a utility's *actual* mix of debt and equity used for its capital financing. *See, e.g.*, *State ex rel. Utilities Comm'n v. Edmisten*, 291 N.C. 575, 579, 232 S.E.2d 177, 180 (1977). *See also* 73B C.J.S. Public Utilities § 104 (2023) ("Generally, the actual existing capital structure will be used to determine the cost of capital"). "The capital structure of the company is a major factor in determining the risk of investing in its bonds or in its stock. Consequently, it is a major factor in determining its cost of capital, which cost determines the fair rate of return." *State ex rel. Utilities Comm'n v. Gen. Tel. Co. of Se.*, 281 N.C. 318, 372, 189 S.E.2d 705, 740 (1972).

Thus, consistent with the Due Process Clause, a utility's ROE must "be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital[,]" *Hope,* 320 U.S. at 603, and determined on the basis of "a number of factual considerations which vary from case to case," *Pub. Staff*, 322 N.C. at 697, 370 S.E.2d at 572. Key among those considerations for purposes of the instant proceeding is whether the applicant utility has equity investors. In determining ROE, the Commission must first determine the reasonable original cost of the utility's rate base and make specific findings of fact regarding changing economic conditions for the utility's customers. *Cooper*, 366 N.C. at 494, 739 S.E.2d at 547.

In addition, a utility's actual, average cost of debt and mix of debt and equity capital typically form the basis for its cost of debt and capital structure for ratemaking purposes. Fundamentally, the goal in setting an utility's overall rate of return, ROE, cost of debt, and capital structure should be to "fix rates as low as may be reasonably consistent with the requirements of" the Due Process Clauses of the state and federal constitutions, *Duke Power*, 285 N.C. at 388, 206 S.E.2d at

276–77. If municipal bond rates and the historical embedded cost of debt can be shown to compensate the parties who provide a utility with *all* the capital financing it relies on *and* that compensation results in low rates for customers, the Due Process clause would require that the ROE and cost of debt be set at those municipal bond rates and the historical average cost of debt respectively. *See generally Hope,* 320 U.S. at 603.

However, "[i]n fixing rates to be charged by a public utility, the Commission is [ultimately] exercising a function of the legislative branch of the government." *Gen. Tel. Co. of Se.*, 281 N.C. at 336, 189 S.E.2d at 717. "[W]hile prior decisions of this Court regarding general questions of law relevant to the ratemaking process [are] entitled to stare decisis effect, the final order of the Commission in a general rate case is not within the doctrine of stare decisis." *State ex rel. Utilities Comm'n v. Virginia Elec. & Power Co.*, 381 N.C. 499, 524, 873 S.E.2d 608, 624 (2022) (internal quotation marks omitted).

B. Agreement and Stipulation of Settlement between the Public Staff and New River is inconsistent with federal and state ratemaking standards.

Pursuant to the Agreement and Stipulation of Settlement between the Public Staff – North Carolina Utilities Commission (Public Staff) and New River (the Stipulation), New River and the Public Staff have agreed to an overall 6.165% rate of return, which is derived from a 3.23% cost of debt, 9.10% ROE, and a *hypothetical* capital structure of 50% common equity and 50% long-term debt. Official Ex. Vol. 4, 77-78, Stipulation at 3-4. By its own terms, the Stipulation "reflects a give-and take of contested issues" with the provisions therein reflecting “instead the compromise and settlement among the Stipulating Parties as to all the issues covered hereby.” Official Ex. Vol. 4, 82, 83, Stipulation at 8, 9. *See also* tr. vol. 4, 53 (“The Company and Public Staff have fundamentally different views of current market conditions and the current cost of capital.”). Even still, the Stipulation’s cost of capital proposals are not grounded in actual costs, and are therefore inconsistent with federal and state ratemaking standards. New River and the Public Staff’s original cost of capital proposals, which each Stipulating Party still contends is reasonable, *see* tr. vol. 4, 59, 291, are infirm on similar grounds.

i. New River is a nonprofit and its ROE should reflect the municipal bond rates available to Appalachian State University and other comparably risky borrowers.

New River’s unique status as both (1) a nonprofit utility with no shareholders and (2) a division of Appalachian State University (App State or ASU) warrants New River’s ROE being set at the municipal bond rate(s) available to App State and comparably risky borrowers as New River would avail itself of municipal bonds to finance its capital financing needs. Prior Commission decisions that have set New River or Western Carolina University’s (WCU) ROE on the explicit or implicit assumption of shareholder compensation are not entitled to precedential effect. *See Virginia Elec. & Power*, 381 N.C. at 524, 873 S.E.2d at 624.

New River “is an operating unit of Appalachian State University.” Official Ex. Vol. 4, 2, Application to Adjust Retail Base Rates at 2. App Voices, New River, and the Public Staff are all in agreement that New River, by virtue of its nonprofit status, does not have shareholders. Tr. vol. 2, 79, vol. 4, 59-61, 291. Consistent with *Public Staff*, 322 N.C. at 697, 370 S.E.2d at 572, New River’s authorized ROE should take into account this factual consideration and changing economic conditions for New River's customers and assure "confidence in the financial integrity of the enterprise, so as to maintain [New River's] credit and to attract capital." *Hope,* 320 U.S. at 603.

Traditional ROE analyses seek to determine how to compensate utility shareholders for the opportunity cost they incur foregoing alternative investments as most electric utilities are investor-owned utilities or subsidiaries of investor-owned utilities. Tr. vol. 4, 59. Failure to set the ROE at a sufficiently high level commensurate with this opportunity cost would inhibit the utility from attracting shareholder investment at reasonable terms. *Id.* at 208. In contrast, an excessive ROE would burden ratepayers with exorbitant capital financing costs. *Id.* Given that New River has no shareholders and instead relies on debt and its retained earnings for its capital financing, *see, e.g.*, tr. vol. 4, 291, at a minimum, any DCF, risk premium method, or capital asset pricing model analysis used to determine New River's ROE must account for this fact and, to the extent possible, incorporate its *actual* capital costs.

App Voices' expert witness Justin Hoyle developed an alternative ROE proposal of 6.25%, which is based on a conservative municipal bond estimate of 5% and 1.25% debt service coverage. Tr. vol. 2, 81. New River satisfies its capital financing needs through a mixture of debt and retained earnings. As neither New River nor the Public Staff have provided any analysis identifying what ROE would be sufficient to ensure an adequate level of retained earnings, it is appropriate to use municipal bond rates as a proxy for New River's ROE as it is a form of capital financing upon which New River has or could conceivably rely. The fact that the Commission may have approved ROEs in the past for New River or WCU that were premised on compensating their "shareholders" does not bind *this* Commission to reach the same outcome. *See Virginia Elec. & Power*, 381 N.C. at 524, 873 S.E.2d at 624. *See also* Order Denying Petition to Intervene of New Energy Economics, Docket No. E-100, Sub 191, at 6 (June 15, 2023) ("While prior Commission precedent is instructive and has persuasive value, it is not binding."). In addition, given there is no evidence that a sale of New River is being contemplated, contending, as the Public Staff has, that a low return on equity might encourage App State to sell New River amounts to largely baseless speculation. Tr. vol. 4, 62.

Furthermore, provided the debt issuance did not obligate the State of North Carolina and the requisite authority had been delegated, and there is no evidence in the record to suggest that this authority has *not* been delegated, New River would only need App State Board of Trustees' approval to use bond debt. Tr. vol. 4, 353-54. As evidenced by a recent $20 million bond issuance, New River's "parent" App State has a Aa3 bond rating. Tr. vol. 2, 68. Although the Moody's credit rating for this bond issuance contains a disclaimer that it provides no opinion "on the equity securities of the issuer or any form of security that is available to retail investors," tr. vol. 2, 127-28, that is of no consequence as App Voices does not contend New River issues equity securities or makes such securities available to retail investors. "[D]uring the past 10 years, the bond rate for municipal bonds rated Baa or better has been under 5%." Tr. vol. 2, 68 (quoting *Rates over Time*

– *Interest Rate Trends*, WM FINANCIAL STRATEGIES, https://www.munibondadvisor.com/market.htm (last visited May 26, 2023)). In addition, the 1.25% "coverage level is identified as reasonable by Moody's Investors Service in its U.S. Municipal Utility Revenue Debt Methodology." Tr. vol. 2, 81 (quoting MOODY'S INVESTORS SERVICE, U.S. MUNICIPAL UTILITY REVENUE DEBT METHODOLOGY 8-9 (2022), https://ratings.moodys.com/api/rmcdocuments/386721#:~:text=We%20measure%20or%20estimate%20utilities,are%20sufficient%20to%20meet%20expenditures.&text=Debt%20service%20coverage%20is%20a,of%20a%20utility%20revenue%20system).

In contrast, neither the Stipulation nor the settlement testimony filed by New River and Public Staff provide any clear guidance as to how the Stipulation's proposed ROE was calculated. The most that can be gleaned from the Stipulation and supporting settlement testimony is that the New River and Public Staff stipulated ROE represents something of a midpoint between the Stipulating Parties' original ROE proposals. Official Ex. Vol. 4, 82, 83, Stipulation at 8, 9 (noting that the Stipulation "reflects a give-and take of contested issues" with the provisions therein reflecting "instead the compromise and settlement among the Stipulating Parties as to all the issues covered hereby."). Indeed, New River and Public Staff continue to maintain the reasonableness of their ROE proposals, *see* tr. vol. 4, 59, 291.

With respect to the Stipulating Parties' specific ROE proposals, New River's original ROE proposal was calculated using ROEs the Commission has previously approved for distribution only, *investor-owned* utility subsidiaries, allowed returns for *investor-owned utilities*, and earned returns for *investor-owned utilities*. Tr. vol. 4, 211. Furthermore, the nationwide allowed and earned returns New River cites to include several ROEs associated with vertically integrated utilities, *see* tr. vol. 4, 295, even though New River's reliance on prior Commission authorized ROEs rests on the argument that this comparison is ultimately appropriate because New River, the Public Service Company of North Carolina and Piedmont Natural Gas are all distribution-only utilities, *see* tr. vol. 4, 211. Given that New River has no shareholder investors, reliance on any of these datapoints in this manner is inappropriate.

Although Public Staff's original ROE proposal was calculated using the DCF analysis and risk premium method, its proposal did not substantively account for New River's nonprofit status. Tr. vol. 4, 34-35 ("[T]he appropriate starting point is to determine the cost rate of common equity as if NRLP had to obtain external capital from the marketplace."). The Public Staff used four factors to identify its peer group of utilities for purposes of its DCF analysis and risk premium method, *see* tr. vol. 4, 37, of which three, namely safety ranks, beta coefficients, and earnings predictability rank, are only appropriate for companies with *tradeable stock*, *see* tr. vol. 4, 68-69. Indeed, it is no surprise then that the Public Staff's peer group is comprised almost entirely of vertically integrated, *investor-owned* electric utilities. Tr. vol. 4, 70. The Public Staff's DCF analysis suffers from other, similar flaws due to its refusal to substantively account for New River's nonprofit status, key among them being the Public Staff's reliance on dividend growth rates and utilities with dividend related risks. Tr. vol. 4, 74-75. The risk premium method is similarly deficient as it is entirely premised on equity investors that New River does not have needing additional compensation to invest in stocks New River does not have as opposed to safer bonds. *See* tr. vol. 4, 78-79. Both Stipulating Parties' decision to ignore the evidence in front of them and develop ROE proposals premised on New River having shareholders, even though New River does not and cannot have shareholders, is a fatal flaw.

Given that the municipal bond rates for bonds rated Baa or better is the only evidence in the record that seeks to quantify the actual costs New River incurs procuring "equity" or approximate the level of retained earnings needed to ensure New River can continue to secure debt at reasonable terms, the Commission should award New River a 6.25% ROE as it is "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Hope,* 320 U.S. at 603. However, App Voices recommends that New River be required to conduct a DCF analysis to optimize its capital structure and submit a compliance filing adjusting the ROE in line with this analysis if necessary.

ii. New River's capital structure and cost of debt should reflect its actual capital structure and historical embedded cost of debt respectively.

As the capital structure for an electric utility should typically reflect its actual mix of debt and equity, New River's capital structure for ratemaking purposes should be 78.3% common equity and 21.7% long-term debt. Tr. vol. 4, 245. Similarly, New River's cost of debt for ratemaking purposes should reflect the historical embedded cost of debt of 2.30%. Tr. vol. 4, 245.

The stipulated capital structure set forth in the Stipulation is 50% common equity to 50% long-term debt. Official Ex. Vol. 4, 77-78, Stipulation at 3-4. The stipulated cost of debt is 3.23%. Official Ex. Vol. 4, 78, Stipulation at 4. The stipulated capital structure appears to be the same hypothetical capital structure the Public Staff originally proposed. Tr. vol. 4, 32 ("I recommend the use of a hypothetical capital structure comprised of 50% common equity and 50% debt."). The same appears to apply for the stipulated cost of debt as well. Tr. vol. 4, 33 ("I recommend an embedded cost of debt of 3.23%.").

With respect to the capital structure, it appears the Public Staff's proposed capital structure (and by extension the stipulated capital structure) was developed in response to concerns that a "large degree of common equity contributes to a higher overall cost of capital *unless adjustments are made to reduce the cost rate for equity to reflect the lower financial risk*." Tr. vol. 4, 31. While the Commission has approved hypothetical capital structures in the past, this would be unnecessary in the instant case if the Commission were to approve the 6.25% ROE App Voices has proposed, which is 285 basis points lower than the stipulated ROE and would save ratepayers approximately $522,120 under New River's originally proposed capital structure. *See* tr. vol. 4, 70-71 ("According to NRLP, each added basis point (1/100th of a percentage point) of ROE adds $1,832 to the total revenue requirement when calculated using NRLP's proposed capital structure 1 of 52% equity and 48% debt.").[1] *See also Gen. Tel. Co. of Se.*, 281 N.C. at 341, 189

[1] The Stipulated capital structure is 50% common equity and 50% long-term debt, so the precise savings App Voices' proposed ROE would deliver customers relative to the Stipulation are

S.E.2d at 720 ("The choice of the appropriate debt-equity ratio is a management decision, but the board of directors may not thereby tie the hands of the Commission and compel it to approve *rates for service higher than would be appropriate* for a reasonably balanced capital structure." (Emphasis added)). Accordingly, it would be appropriate to use New River's actual capital structure of 78.3% common equity to 21.7% long-term debt, provided it were coupled with App Voices' proposed ROE. Tr. vol. 4, 245.

Similarly, while both the Public Staff's cost of debt and the stipulated cost of debt are partially derived from what appear to be embedded cost of debt figures, the Public Staff "imputed additional debt to match the 50% of debt capital of the Public Staff's proposed rate base." Tr. vol. 4, 33. However, a hypothetical capital structure would be unnecessary in the instant case if App Voices' ROE were approved, as it is based on the low municipal bond rates for bonds rated Baa or better. Therefore, the Commission should approve a 2.3% cost of debt for New River, which reflects the actual cost of debt data New River submitted with its general rate case application.

iii. New River should conduct a DCF analysis and submit a compliance filing reflecting this analysis.

While New River submits that its ROE, capital structure, and cost of debt proposals are reasonable for ratemaking purposes in this proceeding, neither New River nor the Public Staff have conducted or at least submitted any cost of capital

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unknown, however, given there is only 2% difference in the common equity mix between New River's originally proposed capital structure and the stipulated capital structure, it is not unreasonable to conclude that there would be significant savings if App Voices' ROE, capital structure, and cost of debt proposals were adopted instead of the Stipulation.

data or analysis that properly accounts for New River's nonprofit status. Accordingly, it is very possible that New River may not be properly optimizing its capital structure. While App Voices acknowledges that the University of North Carolina system is required under N.C. Gen. Stat. § 116D-56 to conduct a debt affordability study every five years, the constituent reports required under Article 5 of Chapter 116D merely require that App State report the debt it owes, how it intends to repay it, any debt it anticipates issuing, along with a few other pieces of information. *See* N.C. Gen. Stat. § 116D-56(c). The scale and reach of both the university system debt affordability study and App State constituent reports are too broad to inform how New River should best optimize its capital structure. Similarly, the cadence of the debt affordability study, which the university system is required to conduct once every five years, make that tool a poor fit for ratemaking purposes. Furthermore, the main indicia in the debt management policy that App State seems to propose as a potential substitute for a DCF analysis[2] is by its own terms, a limited tool. THE UNIVERSITY OF NORTH CAROLINA SYSTEM, REPORT ON FY 2020 UNC SYSTEM DEBT CAPACITY STUDY 41 (2020) ("ASU recognizes that the policy ratios, while helpful, have limitations and should not be viewed in isolation[.]"), https://www.northcarolina.edu/wp-content/uploads/reports-and-documents/finance-documents/debt-capacity/final_report-on-fy-2020-unc-system-debt-capacity-study-full-report.pdf. What is more, New River conceded on the stand that App State is not projected to exceed any of those policy ratios at any point in the next five years. Tr. vol. 4, 355.

[2] *See* tr. vol. 4, 344.

Accordingly, New River should be directed to conduct a DCF analysis to optimize its capital structure. Should that DCF analysis reveal a different capital structure, ROE, and/or cost of debt is appropriate, New River should then submit a compliance filing reflecting these results.

3. The Commission should approve Schedule NBR, but modify it to remove the SSC and eliminate annual forfeiture of accrued net excess credits in order to accurately reflect the costs incurred and benefits provided by customer-sited distributed solar resources.

Rooftop solar adoption depends on policy. The Commission has seen the sad effect of NRLP's longstanding buy-all-sell-all policy: on a system of approximately 8,900 customers, tr. vol. 4, 96, there are approximately 14 rooftop solar customers, total, tr. vol. 2, 267-268. In concept, NRLP's proposed net billing rider, Schedule NBR, is a major improvement over buy-all-sell-all because it allows a customer to consume the electricity that their system produces. Net billing is the right framework for compensating NRLP's rooftop solar customers and for that reason the Commission should approve proposed Schedule NBR, with modifications.

The Commission should make two modifications to Schedule NBR. First and foremost, it must eliminate, or at a minimum greatly reduce, the "Standby Supplemental Charge" (SSC). Second, it should eliminate the annual "reset" that would erase rooftop solar customers' accrued credits. The effect of these modifications will be to create, finally, a rooftop solar policy that can probably work for NRLP's customers. The effect of allowing NRLP to proceed with its flawed policy will very likely be to leave rooftop solar adoption stagnant in Boone. That is one of the reasons the Commission should not adopt a "wait and see" approach; if it allows NRLP to adopt Schedule NBR as proposed then there very likely will be negligible solar uptake, and nothing to see.

A. The proposed SSC is unnecessary.

NRLP has argued that its proposed SSC is necessary for NRLP to recover its full fixed costs from rooftop solar customers, but NRLP is deeply wrong. NRLP's mistake appears to begin with the mindset with which it approaches determining compensation for customer-generators other than ASU. Where ASU is concerned, NRLP has been content to offer some form of net metering for at least a decade. Appalachian State University - Kerr Scott Hall PV, Application to Register a Renewable Energy Facility or New Renewable Energy Facility Pursuant to Rule R8-66 at 4, Docket No. SP-283, Sub 13 (N.C.U.C. Feb. 12, 2013) (describing facility as "currently net-metered"); *compare* tr. vol. 4, 120-121 (denying NRLP has compensated solar through net billing or net metering). To this day, ASU's "billing rate is designed to net out any generation that's behind the campus meter," tr. vol. 4, 122-123, and that is how ASU is compensated for the electricity generated by its windmill, for example*, id.* 122-123. When ASU was considering developing a solar-plus-storage facility, NRLP contemplated a compensation scheme that involved straightforwardly over-billing the state of North Carolina, which pays ASU's utility bills, in order to make sure that the facility offered savings to ASU, and NRLP appeared to abandon the scheme only because it involved an unreasonably high "Extra Facilities Charge."[3] Appalachian Voices, Cross Examination Miller Direct, Exhibit #1-4; *see* tr. vol. 4, 126-132 (discussing proposal), 278 (Halley confirming).

NRLP does not similarly bend over backwards to make sure that its non-ASU customers can save money through investments in customer-sited generation, and it shows in NRLP's flawed analysis underlying the SSC. At the end of accounts, NRLP has proposed an SSC of $5.92 per kW per month for residential customers on Schedule R, $6.39 per kW per month for customers on Schedule G, and $3.59 per kW per month for customers on Schedule GL. Halley Settlement Exhibit No. 1, unnumbered pages 23-24. An SSC in this range will prevent rooftop solar adoption in Boone just as surely as buy-all-sell-all has. Residents of Boone considered the slightly higher SSC of $6.17 per kW per month that NRLP initially proposed "enormous," Transcript of Public Witness Hearing Held in Boone on Tuesday, May 23, 2023, Volume 1, 32, a "deliberate disincentive," *id.* at 33, "shocking" and "unfair" as a flat fee per kW, *id.* at 35-37, "exorbitant," *id.* at 42, a steep "penalty," *id.* at 50, a solar "killer," *id.* at 50, and embarrassing and disappointing, *id.* at 55-56. One resident contemplating installing rooftop solar calculated that the proposed SSC would extend the payoff period from an already lengthy twenty-five years to forty-three years. *Id.* at 32-33. No witness testified that the fee could support rooftop solar adoption.

[3] The proposal involved first calculating the amount of NRLP's savings under its contract with CPP as a result of the solar-plus-storage facility's operation, then providing that amount of savings to ASU in cash, and then *also* charging ASU an "Extra Facilities Charge" of the same amount, which would be paid by the State of North Carolina. Appalachian Voices, Cross Examination Miller Direct, Exhibit #2.

Adding insult to injury, the SSC is unnecessary. NRLP is not subject to the requirements of House Bill 589 (H589), G.S. §§ 62-126.4(a) (applying to each "electric public utility"), 62-126.3(7) (defining electric public utility per G.S. § 62-3), G.S. § 62-3(23)(e.), including as the requirement that each net metering retail customer pay its full fixed cost of service, G.S. § 62-126.4(b). Nonetheless, the Commission surely will want to ensure that any cost-shifting from non-net metering customers to net metering customers is minimized, recognizing that fully eliminating cost-shifting among customers is impossible. Tr. vol. 3, 140; *see also* Order Approving Revised Net Metering Tariffs 12, *In the Matter of Investigation of Proposed Net Metering Policy Changes*, Docket No. E-100, Sub 180 (N.C.U.C. March 23, 2023) (acknowledging "the Public Staff believes it is impossible to absolutely eliminate any cross-subsidy"). But on the evidence in this proceeding, an SSC is not required to achieve that goal.

Under proposed Schedule NBR without any SSC, there would be no cross-subsidy from non-rooftop solar customers to those on Schedule NBR. In fact, residential rooftop solar customers already would pay *more* than their fair share of NRLP's fixed costs under Schedule NBR without an SSC, meaning a small cross-subsidy would flow in the other direction. Tr. vol. 2, 197. The Commission should be just as alert to cost shifting flowing *from* rooftop solar customers *to* non-rooftop solar customers as it has historically been to cost-shifting in the other direction. Tr. vol. 3, 140-141 (Witness McLawhorn recognizing that the Public Staff would want to minimize any cross-subsidy from solar customers to non-solar customers). Any SSC at all would only deepen the cross-subsidy flowing from any rooftop solar customers who decided to install--despite the punishing economics--to NRLP's other customers. As the stipulation between NRLP and the Public Staff contemplates, the Commission should require NRLP to report on the effects of Schedule NBR and if the reporting convincingly shows evidence of cost-shifting the Commission could address it at that time.

B. NRLP's SSC calculation under-values customer-sited solar.

There were six main methodological errors in NRLP's calculation of the SSC, each of which reduced the value of customer-sited solar in NRLP's view, as explained by Appalachian Voices Witness Justin Barnes. Tr. vol. 2, 178-181. Two of the more minor issues were subsequently addressed or resolved.[4] As a result of the four remaining issues, the SSC remains unjustifiable. First, customer-sited solar allows NRLP to avoid high costs during monthly coincident peak hours, but NRLP's SSC calculation artificially capped this value at the averaged volumetric residential retail rate. Second, customer-sited solar allows NRLP to avoid future marginal distribution capacity costs, which likely are high. Third, customer-sited solar produces more during NRLP's monthly coincident peak hour than NRLP estimated. Finally, NRLP's proposed annual "reset" erasing customer-generators' accumulated credits every January 1 is unnecessary and penalizes customer-generators.

[4] These are "SSC Issue #4," concerning applying the SSC to all Schedule NBR customers when its calculations were based on residential customers only, and "SSC Issue #5," NRLP's proposal to levy the SSC charge based on the AC nameplate capacity of the customer's inverter rather than the system design capacity. Tr. vol. 2, 179-180.

i. Customer-sited solar allows NRLP to avoid high costs during monthly coincident peak hours.

The biggest problem with NRLP's calculation of the SSC is the artificial limit NRLP placed on the value of the costs avoided by customer-sited solar. Tr. vol. 2, 178. The way NRLP calculated the value of solar is as follows. First, NRLP calculated the *cost* of customer-sited solar to NRLP, which it measured by multiplying estimated system production of those solar systems in kWh by the volumetric retail rate(s). Tr. vol. 2, 181-182. Next, to calculate benefits, NRLP calculated the contribution of customer-sited solar to avoiding those *same* retail rates, according to how the costs underlying those specific rates are incurred. *Id.* at 182. For wholesale energy rates, solar generation offsets purchases at a 1:1 ratio, because incremental customer solar production completely offsets energy NRLP would otherwise have to provide through wholesale purchases. Tr. vol. 2, 182. For the demand-related costs, NRLP calculated the capacity that customer-sited solar would provide at the time that monthly peak demand occurred, resulting in contribution percentages ranging from 26% to 29%, and then multiplied these percentages by the corresponding demand-related cost components underlying residential rates. Tr. vol. 2, 182-183; *see* Tr. vol. 3, 10-11 (discussing "derating"). Finally, NRLP added together these figures to get the total cost avoided by solar, approximately 8.9 cents per kWh. Tr. vol. 2, 183.

NRLP went wrong at step one. The value that customer-sited solar provides to NRLP's system is determined by the overall, total costs that NRLP avoids as a result of the customer-sited solar; there is no reason to limit that value to the volumetric retail rate. This problem comes into sharpest focus in the analysis of

NRLP's avoided demand costs. NRLP's costs are primarily driven by monthly coincident peak demand, or highest demand on the NRLP system each month. Tr. vol. 4, 233; Tr. vol. 3, 97, 103 (Wit. McLawhorn explaining that contractual coincident peaks are large drivers of cost causation). As is the SSC. Tr. vol. 3, 133. The value to NRLP of reducing demand at that time is high. For example, for high-demand commercial and industrial customers on Schedule GL, it is worth $14.26 per kW of load actually reduced during NRLP's monthly coincident peak hour. Halley Settlement Exhibit No. 1, unnumbered page 35 (Schedule "IR").

When customer-sited solar generates during coincident peak, it will reduce NRLP's costs under its contract to the extent that it reduces NRLP's demand, just like any other resource that reduced demand at that time. Tr. vol. 3, 135. That is why the proper measure of its value is demand unit costs. Tr. vol. 2, 184-185; Tr. vol. 3, 18-19; 45. Customer-sited solar is really worth approximately $15.97 per kW of load actually reduced during NRLP's monthly coincident peak hour.[5] Tr. vol. 2, 186-187. But the residential retail rate that NRLP used instead of demand unit costs is an averaged flat volumetric rate, which means that it takes the customer class's demand-related costs and spreads them across the customer class's usage; it does not increase at coincident peak times. Tr. vol. 3, 19. The averaged flat residential volumetric rate is much lower than the cost that NRLP actually avoids by reducing demand during coincident peak hours. Accordingly, NRLP's

[5] Measuring the demand *actually* reduced by customer-sited solar during the coincident peak hour already accounts for the capacity factor of solar during the coincident peak hour, which will be something less than 100%; for example, NRLP calculated solar contribution to peak in the 26% to 29% range. To the extent customer-sited solar produces during coincident peak, one kWh of energy actually produced during that hour is just as valuable as one kW of demand reduced during that hour. *See* tr. vol. 2, 188.

decision to artificially cap the value of customer-sited solar at the residential retail rate at all times greatly undervalues the costs that it avoids. Tr. vol. 2, 186-187 (reducing annual value from actual $191.66 to $33.16). As Public Staff witness McLawhorn acknowledged, Appalachian Voices Witness Barnes is “probably technically correct” that valuing customer-sited solar at an average flat volumetric rate does not take into account the cost avoided by solar’s contribution to monthly coincident peak. Tr. vol. 3, 133-134. This error is particularly baffling because NRLP got it right in its proposed interruptible rate, Schedule IR. Tr. vol. 2, 187.

One way to describe the problem with NRLP’s calculation of customer-sited solar’s contribution to monthly coincident peak is to say that NRLP effectively discounted the value of solar twice over, first by (properly) reducing solar’s contribution to meeting monthly coincident peak according to its effective capacity factor at that time, and a second time (erroneously) by using the averaged flat volumetric rate to measure the cost avoided by solar during the monthly coincident peak. Tr. vol. 3, 19. But since the problem is the second part, it is simpler to say that when NRLP calculated the costs that customer-sited solar allows NRLP to avoid—the value solar provides to NRLP--it arbitrarily capped the value of solar during the monthly coincident peak hour at the residential retail rate, instead of using the much higher demand unit costs that the solar production actually allows NRLP to avoid. And this greatly reduced the value of solar as calculated by NRLP.

NRLP and the Public Staff gave unconvincing justifications for this error. On cross examination, NLRP Witness Halley gave two reasons for limiting the value of customer-sited solar during coincident peak to the averaged flat volumetric retail rate. The first reason was that the effective capacity factor of solar will not be 100% during that hour. Tr. vol. 4, 286-287. That justification is a non-sequitur. As just described, it is appropriate to discount the overall capacity of customer-sited solar by its effective capacity factor during the monthly coincident peak hour, but what Witness Halley needed to provide was a reason to limit the compensation for the *actual* generation from solar—a figure that already inherently takes into account solar's effective capacity value--during that hour to the residential retail rate. Witness Halley's second justification was that NRLP collects some of its fixed costs from residential customers through the volumetric rate. Tr. vol. 4, 287-288. That justification is also a non-sequitur; at best, it is simply NRLP's justification for having any SSC at all, and says nothing at all about why the value of solar should be limited to the residential retail rate.

The Public Staff, which also agreed to the final SSC in its stipulation with NRLP, gave a puzzling justification: NRLP does not have the right rates. Public Staff Witness McLawhorn acknowledged that a resource that contributed to avoiding NRLP's costs at a time when NRLP incurred higher costs would avoid higher costs, but stated, "that's not the way New River's rates are designed to work." Tr. vol. 3, 127. Later, after acknowledging that solar generating during coincident peak would offset NRLP's coincident peak costs, Witness McLawhorn suggested that some sort of time- or seasonally varying rates would be required to compensate solar fully. Tr. vol. 3, 136. This justification misses the mark. Witness McLawhorn responded as though the question were how to compensate customer-sited solar through rates, but that is not the case. At issue is simply the accuracy of the *calculation* underlying NRLP's proposed SSC; there is no reason NRLP would need a special rate for solar customers in order to accurately calculate the costs that NRLP itself avoids, which are governed by its wholesale and other contracts. Fundamentally, the calculation of the value the customer-sited solar provides should be based on the *actual costs* that it allows NRLP to avoid. There is no reason that the calculation cannot take into account the full costs that NRLP actually avoids, or that those avoided costs are somehow capped at the residential retail rate.

The value of customer-sited solar on NRLP's system should fully reflect the actual costs that it allows NRLP to avoid. NRLP's costs are primarily driven by monthly coincident peak demand. To the extent that customer-sited solar generates during the monthly coincident peak demand hour, it allows NRLP to avoid high costs, costs much higher than the averaged volumetric residential retail rate. Artificially capping the value of customer-sited solar at that residential retail rate, as NRLP did, unjustifiably erases a large portion of the value provided by solar. Accordingly, NRLP greatly undervalued customer-sited solar when it calculated the SSC and its proposed SSC is too high.

ii. Customer-sited solar allows NRLP to avoid marginal distribution costs.

The second-biggest problem with NRLP's calculation of the SSC is its decision to incorrectly assign zero avoided distribution capacity value to customer-sited solar generation. Tr. vol. 2, 185-186. This is a simple error. Any utility with a distribution system will have marginal distribution costs and including them as a potentially avoidable cost is “nearly universal.” Tr. vol. 2, 189; *see* Panel of Janice Hager, Michael J. Pirro, Lon Huber, Stipulated Testimony from DEC Evidentiary Hearing, Public Staff 11 Pirro/Hager Cross Examination Exhibit 1, Jim Lazar, et al., Regulatory Assistance Project, Electric Cost Allocation for a New Era at 58 (describing factors driving load-related distribution costs), 203 (describing calculation of marginal shared distribution costs), Docket No. E-2, Sub 1219 (N.C.U.C. Sept. 30, 2020).

The Commission has agreed in the past. In the Duke Energy net metering proceeding, the Commission approved, as modified, net metering tariffs that were based on a Rate Design Study in which both the marginal and embedded cost studies recognized benefits in terms of distribution capacity. Order Approving Revised Net Metering Tariffs, *In the Matter of Investigation of Proposed Net Metering Policy Changes*, Docket No. E-100, Sub 180, 2023 WL 2691609, at *26 (Mar. 23, 2023). The Commission approved the proposed monthly minimum bill in Duke’s net metering tariffs in order to recover distribution-related costs to serve NEM customers—[u]ntil it can be definitively determined that distribution-related costs to serve NEM residential customers are significantly less than the fixed cost to serve non-NEM residential customers.” *Id.* at 35.

And customer-sited generation can allow NRLP to avoid substantial marginal distribution capacity costs. Solar production is well-aligned with the timing of NRLP’s monthly coincident peaks, which are used to allocation distribution costs. Tr. vol. 2, 189-190. Furthermore, NRLP’s embedded distribution costs are relatively high, tr. vol. 2, 190, indicating that NRLP’s avoidable marginal distribution costs, though not measured by NRLP and therefore not known, are correspondingly high, tr. vol. 2, 195-196. The marginal distribution costs that customer-sited generation can avoid are substantial, at approximately $0.05/kWh. Tr. vol. 2, 197.

NRLP ignored this value in its calculation of the SSC because it incorrectly assumed that customer-sited solar cannot avoid any marginal distribution capacity costs. NRLP gave two reasons for this mistaken assumption, neither of which has merit. The primary rationale that NRLP offered for this assumption is that it has no marginal distribution capacity costs because all of its distribution costs are fixed and would not be avoided if a customer installed and used solar. Tr. vol. 4, 254, 280-281, 283-284. This is wrong. Witness Halley appears to have confused embedded costs with marginal costs, or put differently, to have denied the existence of future marginal distribution capacity costs. It is true that new customer-sited solar would not avoid embedded distribution capacity costs, which are past and spent, but that is not at issue; Witness Barnes's analysis did not assume that customer-sited solar can avoid embedded costs. But customer-sited solar can avoid *future* marginal distribution capacity costs. Tr. vol. 2, 185-186, 188. And when pressed, even Witness Halley acknowledged that NLRP has future distribution system costs. Tr. vol. 4, 281.

The second rationale NRLP offered is that rate design does not consider future costs. Tr. vol. 281-282. Importantly, this rationale implicitly concedes the first point—it acknowledges that there are future marginal distribution costs that could be avoided, but claims that NRLP could not credit customer-sited solar accordingly because rates are backward-looking only. That is wrong. Like Witness McLawhorn's mistaken claim that NRLP would need different rates in order to credit the value of customer-sited solar to coincident peak demand reduction, Witness Halley's rationale confuses rate-setting with calculating NRLP's avoidable costs. The calculation underlying the SSC should be based on the actual costs that customer-sited solar allows NRLP to avoid. As Witness Halley conceded, NRLP has future marginal distribution system capacity costs, and he gave no reason that the *calculation* of the costs that customer-sited solar allows NRLP to avoid could not include those avoidable costs—because there is none. If the SSC calculation excludes avoidable future marginal distribution costs because they will occur in the future, by the same principle the calculation could exclude any costs that new customer-sited solar could avoid, like avoided wholesale energy costs, because all will occur in the future; the principle is untenable.

NRLP incorrectly assigned zero avoided distribution capacity value to customer-sited solar generation, artificially reducing the calculated value of customer-sited solar by approximately $0.05/kWh.

iii. Customer-sited solar produces more during NRLP's monthly coincident peak than NRLP estimated.

The contribution that customer-sited solar makes to monthly coincident peak depends on how much it actually produces—its effective capacity factor—during that hour. NRLP was right to take this into account when it calculated costs that customer-sited solar allows NRLP to avoid. But NRLP underestimated the effective capacity factor of customer-sited solar because it relied on questionable solar production data and used a deeply flawed methodology to fill in gaps in the data. Tr. vol. 2, 10. NRLP is missing large amounts of solar production data for the few customer-sited solar arrays on NRLP's system. Tr. vol. 2, 191-192. But NRLP needed full production profiles to estimate the effective capacity factor of customer-sited solar during NRLP's monthly coincident peak. To fill in the gaps, NRLP simply averaged the difference between the last valid reading and the next valid reading, effectively assuming that solar production was flat between those hours. Tr. vol. 2, 193. This is a terribly inaccurate way to fill in the missing data because solar production is not flat over time; it follows a highly predictable curve that peaks around noon. Tr. vol. 2, 193.

During the course of the proceeding, NRLP appeared to attempt to address this problem. It adjusted the amount of renewable energy used in its development of Schedule NBR and Schedule PPR to recognize the portions of hourly load data missing from its initial analysis. Tr. vol. 4, 107. But it did not really fix the problem. On examination by Commissioner Clodfelter, Witness Halley explained that NRLP took its record of the total generation from a given customer-sited solar array and allocated it back through the missing hours. Tr. vol. 4, 311-312. This should be slightly more accurate than NRLP's initial averaging approach, because the overall amount of energy generated comes from metering data. But it does not appear to address the key question for determining the value of customer-sited solar, which is *when* it generates, and specifically, the extent to which its generation lines up with NRLP's monthly coincident peak. It is not surprising that NRLP would not address that question because NRLP artificially capped the value of customer-sited solar at the averaged flat volumetric retail rate, which was a separate error discussed above.

Using more accurate solar production profiles generated by the National Renewable Energy Laboratory's PVWatts Calculator, Witness Barnes calculated the effective capacity contribution of customer-sited solar during NRLP's coincident peaks at 26.9% to 32.7%, a range greater than NRLP's estimates. Tr. vol. 2, 189-190. Accordingly, NRLP underestimated the value of customer-sited solar. The Commission should not wait for NRLP to produce more complete solar production data in a future proceeding before directing NRLP to correct this error because this error, in combination with the others discussed herein, results in an SSC that will inhibit any significant rooftop solar adoption in NRLP's service territory, which will limit the data available in the future.

C. Zeroing-out customer-generators' accrued excess generation annually on January 1 is unnecessary and deepens the cross-subsidy from customer-generators to other customers.

NRLP's initial proposal to erase customer-generators' accrued excess generation credits on January 1 unnecessarily penalizes customer-generators. To its credit, during the proceeding NRLP revised its position and offered to remove the annual reset of credits for customers. Tr. vol. 4, 243; Tr. vol. 2, 276-277. Doing so would not be technically difficult. Tr. vol. 2, 260. However, the Public Staff supports an annual reset, tr. vol. 3, 101-104, and opposes allowing customers to select their reset period precisely because it seeks to have the annual reset erase a "significant bank" of credits, tr. vol. 159. And ultimately the stipulation between NRLP and the Public Staff included the annual reset, tr. vol. 4, Ex. X ¶¶ 23, 30, because the Public Staff believes that it is necessary to prevent cross-subsidization, tr. vol. 3, 157-159.

Annual resetting is flawed for three main reasons. *See* tr. vol. 2, 180-181. First, it conflicts with NRLP's SSC calculation. In its SSC calculation, NRLP simply multiplied the annual generation of a customer-sited solar array by the residential retail rate. This necessarily assumes that the customer-generator uses every kilowatt-hour that their system generates to offset their consumption. If NRLP erases a customer's accumulated credits once per year, then the customer cannot use those credits to offset their generation. But NRLP made no adjustment to its SSC calculation to reflect this fact. Tr. vol. 2, 180; Tr. vol. 3, 24. Accordingly, NRLP's proposal to annually erase accumulated credits conflicts with its SSC calculation.

Second, annually erasing accumulated credits will effectively prevent customers from sizing their solar PV systems to offset 100% of their usage. Tr. vol. 2, 180-181. This is because a system sized to meet 100% of a customer-generators needs on an annual basis will maintain surplus credits during some portion of the year, quite possibly into the winter, and a "reset" that erased those credits would erase that value. Tr. vol. 2, 262-263. To be sure that they received the full value of their system, a customer would need to under-size it to minimize the credits lost during the reset. Allowing customers to choose their reset dates would reduce this concern. Tr. vol. 2, 263.

By the same token, an annual reset inherently discourages customers from "over-sizing" the solar PV systems they install, because a customer would never see any benefit from accumulated credits that were not used to offset the customer's usage, meaning the excess solar capacity that the customer installed above and beyond what was needed to offset 100% of their usage would do them no financial good, it would be a cost with no benefit. Tr. vol. 2, 261-262.

Finally, as discussed in Witness Barnes' testimony, an accurate and complete analysis shows customer-generators on Schedule NBR would likely provide net savings to NRLP, tr. vol. 2, 197, meaning that even absent an SSC, those customers are cross-subsidizing NRLP's other customers. Annually erasing their accrued credits deepens this cross-subsidy by erasing some of the benefit of the customer-generators systems.

The Public Staff's reason for supporting the annual reset does not meaningfully address these flaws. The driving rationale behind the Public Staff's support for resetting appears to be elimination of a perceived cross-subsidy from non-participating customers to customer-generators; that is why it deemed at least annual resetting essential, tr. vol. 3, 157-159, and maintaining annual resetting to eliminate cross-subsidies was one of the reasons it did not insist on monthly resetting, tr. vol. 3, 102-103. But that cross-subsidy does not exist; to the contrary, there is a cross-subsidy in the other direction and the Public Staff should oppose deepening it. Tr. vol. 3, 140-141.

4. **The Commission should deny NRLP's proposal to increase the "Basic Facilities Charge" because it is not based on sound methodology and does not accurately reflect the per-customer costs NRLP incurs.**

NRLP's "Basic Facilities Charge" (BFC) has been growing at an alarming rate. In its last rate case in 2017, NRLP prepared a cost-of-service study in which it calculated the average monthly cost per residential customer to be $17.81 for customer-related expenses, $20.39 for commercial non-demand customers, and $98.75 for commercial demand service, which it used to justify proposed fixed charges of $12.58, $17.42, and $23.22, respectively. Direct Testimony of Randall E. Halley 21:530-22:562, *In the Matter of Application of Appalachian State University, d/b/a New River Light and Power Company, for an Adjustment of Rates and Charges for Electric Service in North Carolina*, Docket No. E-34, Sub 46 (N.C.U.C. July 28, 2017). Compared to NRLP's previous fixed charges, each represented an increase of precisely 100%. *Id.* For the residential and commercial non-demand customer classes, that doubling of the fixed charge produced more than half of the total new revenue requirement. Order Accepting Stipulation and Granting Increase in Rates 16 (Comm'r Clodfelter, dissenting), *In the Matter of Application of Appalachian State University, d/b/a New River Light and Power Company, for an Adjustment of Rates and Charges for Electric Service in North Carolina*, Docket No. E-34, Sub 46 (N.C.U.C. Mar. 29, 2018).

In this rate case, NRLP proposed to increase the residential BFC from $12.58 to $14.50 per month. Tr. vol. 2, 204; Tr. vol. 4, 229. The only justification NLRP offered for its proposed increase is that it calculated its fixed costs to serve residential customers to be $36 per month. Tr. vol. 2, 204. That amount is more than double the $17.81 average monthly cost per residential customer that it calculated for the 2017 rate case just six years ago. Yet the number of customers NRLP serves increased only 10.1% during the same period. Tr. vol. 2, 220.

NRLP's proposed BFC is too high. NRLP used an inappropriate benchmark in its calculated $36 per month residential fixed cost. Tr. vol. 2, 204-205. That figure includes costs associated with NRLP's shared distribution system upstream of a customer's service drop, which are caused by customer demands rather than the number of customers on a system. Tr. vol. 2, 204-205. Because those costs are not caused by the number of customers on the system, they should not be part of a fixed customer charge. *Id.* Again, the only justification for NRLP's proposed $14.50 BFC is that it is a "modest step" closer than $12.58 to $36. Tr. vol. 4, 255. The Commission should rein in NRLP's fixed customer charge before it begins proposing bold steps.

Customer-related costs should not be the dumping ground for all the costs that cannot plausibly be attributed to another cost factor. Tr. vol. 2, 242. A fixed customer charge should be "limited to those costs that are incurred based on the number of customers," tr. vol. 2, 205, namely, "the cost of the customer meter, the service drop, and any other facilities uniquely attributable to a specific customer," Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Comm'r Clodfelter, concurring in part and dissenting in part 51, *In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-7, Sub 1146 (N.C.U.C. June 28, 2018) [Clodfelter Dissent]. This "basic customer method" is used by the majority of other jurisdictions. *Id.* at 51-52; Tr. vol. 2, 258-259.

Commissioner Clodfelter reviewed many compelling reasons to adopt the "basic customer method" rather than the "minimum system method" in his 2018 dissent in the DEC rate case. Clodfelter Dissent 48-54. The "minimum system method" is based on a "hypothetical" or "phantom" system that the utility never built. *Id.* at 49 (quoting James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, 347-348 (1961)). The cost of that imaginary minimum system is only very weakly correlated with the number of customers served, and possibly not at all if the utility's entire service area stays fixed, *id.*, as is the case with NRLP. Especially on today's modernizing grid, it is increasingly difficult to determine which, if any, distribution system costs are a direct function of the number of customers served. *Id.* at 49-50. Rather, distribution system investment is causally related to peak demand. *Id.* at 50. The minimum system method effectively double-counts demand-related costs because a minimum system is capable of serving some level of demand. *Id.* At the end of accounts, it is the costs of the "real world system that must be allocated, and those costs are heavily driven by demand." *Id.* at 51.

NRLP argued that its "minimum system method" is more in line with North Carolina utility regulation and past decisions, tr. vol. 4, 256, but it is wrong. NRLP used a "modified version of the minimum system method," tr. vol. 4, 256, that has never been used in North Carolina before, *see* tr. vol. 4, 288-289. Witness Halley calculated that without his modifications to the "minimum system method" it would have produced a fixed customer charge in excess of $36. Tr. vol. 256. As it stands, NRLP's calculated fixed cost to serve residential customers nearly *triples* the existing BFC, which is already *double* the last BFC. In other words, the methodology NRLP has proposed produced a result that even NRLP recognized is unacceptable, so it modified the methodology. The Commission should adopt the "basic customer method" instead of NRLP's outcome-driven variation on the flawed "minimum system method."

The passage of House Bill 951 (H951) does not affect the appropriateness of using the "basic customer method" in this rate case. H951 required the Commission to use the "minimum system method" if it approves performance-based regulation for an electric public utility. G.S. § 62-133.16(b). But NRLP did not apply for performance-based regulation, and in any case is not an electric public utility. G.S. § 62-3(23)(e.). The Commission regulates NRLP's rates under a separate statutory provision entirely, governing the sale of excess power from power plants operated by UNC constituent institutions like ASU. G.S. § 116-35. Had the General Assembly wanted to establish an overarching policy favoring the "minimum system method" and requiring the Commission to adopt it in all instances, it could have done so. *Mascot Stove & Mfg. Co. v. Turnage*, 183 N.C. 137, 110 S.E. 779, 780 (1922) ("The object of all interpretation, or construction, is to ascertain the meaning and intention of the Legislature, to the end that the same may be enforced, which must be sought for first of all in the language of the statute itself, for it must be presumed that the means employed by the Legislature to express its will are adequate to the purpose, and do express that will correctly.")

Using the "basic customer method" results in a residential BFC of $10.61 per month, or as low as $10.38 per month if certain revenue-allocated expenses are excluded. Tr. Vol. 2, 215-216. This is a more appropriate BFC because unlike NRLP's proposal it is cost-based, and for all of the reasons discussed above, the "basic customer method" is superior to the "minimum system method." But there are other guideposts as well: even without adopting the "basic customer method," correcting various errors in NRLP's methodology or revenue requirement results in BFCs ranging from $10.81 to $13.86, each of which is lower than NRLP's proposed $14.50. Tr. vol. 2, 222. Recall, for this comparison, that NRLP's initial application of the "minimum system method" produced a monthly residential fixed cost exceeding $36; it modified the "minimum system method" to reduce the fixed cost and arrived at $36; and then it arbitrarily chose $14.50 as its proposed residential BFC because it is lower than the unacceptable $36. By contrast, the corrected methodologies reviewed by Witness Barnes arrive at the range above organically based on actual costs. Tr. vol. 2, 208-215, 218-222.

For the foregoing reasons, the Commission should authorize a residential BFC of no more than $10.61 per month.

5. NRLP's customers deserve energy efficiency and demand-side management (EE/DSM) programs.

NRLP's customers have not benefited from NRLP's investment in "advanced metering infrastructure" (AMI) as they should have. In NRLP's 2017 rate case, it justified its investment in AMI on the grounds that it would provide "benefits to NRLP and its customers, including faster outage detection and restoration of service, consumer information that will allow customers to reduce electricity use during peak demand periods and take advantage of rates and programs designed to reduce costs for the consumer and NRLP." Direct Testimony of Edmond Miller 10:160-65, *In the Matter of Application of Appalachian State University, d/b/a New River Light and Power Company, for an Adjustment of Rates and Charges for Electric Service in North Carolina*, Docket No. E-34, Sub 46 (N.C.U.C. July 28, 2017). NRLP and the Public Staff reached a stipulation in the 2017 rate case under which NRLP agreed to work with the Public Staff "to develop rate schedules and energy efficiency and demand side management programs that take advantage of the detailed usage data and other capabilities of its AMI metering system, recognizing that NRLP may not implement energy efficiency or demand side management program" under its contract with BREMCO. Stipulation ¶ 38, *In the Matter of Application of Appalachian State University, d/b/a New River Light and Power Company, for an Adjustment of Rates and Charges for Electric Service in North Carolina*, Docket No. E-34, Sub 46 (N.C.U.C. Jan. 19, 2018).

The Commission need not find that NRLP has violated the letter or the spirit of this agreement to see that NRLP's customers do not have access to EE/DSM programs, and that NRLP is not putting its AMI infrastructure to its highest and best use. Witness Miller acknowledged that NRLP has not proposed a "slate of DSM/EE programs." Tr. vol. 4, 110. Witness Miller implied that NRLP complied with the terms of its agreement with the Public Staff because no one contended otherwise and NRLP developed a prepaid service rider and its Green Power rider. Tr. vol. 4, 109-110, 136. But only one of these programs, the prepaid service rider, makes use of the capabilities of NRLP's AMI, and both programs leave much to be desired.

Under NRLP's prepaid service rider, AMI allows NRLP to disconnect and reconnect customers more quickly. North Carolina utilities are not allowed to disconnect service without having first tried to induce the consumer to pay, Rule R8-20(a), and must allow a customer to pay a delinquent bill at any time prior to disconnection, Rule R8-20(d). A regular residential customer on Schedule R typically has two months between when they run out of money and when NRLP disconnects their power. Tr. vol. 4, 135. NRLP sought and obtained a waiver of those Commission Rules. Under the prepaid service rider, a customer is disconnected the next business day unless "the temperature reaches, or is expected to reach, 32° or lower over a weekend or a state or federal holiday," in which case disconnection is postponed. New River Light and Power's Prepaid Service Rider - Schedule "PSR" at 2 item 6, *In the Matter of Petition of Appalachian State University, d/b/a New River Light and Power Company, for Approval of a Prepaid Rate Schedule and Request for Waivers of Billing and Metering Requirements*, Docket No. E-34, Sub 49 (June 22, 2022). Under the prepaid service rider, in 2022 it cut power to between 33 and 70 accounts per month, except for February and March, when it was presumably too cold. New River Light and Power's Pilot Prepaid Service Rider (Schedule PSR), Annual Report 1/1/2022 to 12/31/2022, Docket No. E-34, Sub 49 (N.C.U.C. May 26, 2023). NRLP cut power between 47 and 120 times per month during those same months, indicating that it cut power to some customers more than once. *Id.* It cut power to 69 customers more than once within a 90-day period. *Id.* Prepaid service is, generally speaking, bad for low- and moderate-income customers. North Carolina Justice Center, Consumer Statement of Positions, Docket No. E-34, Sub 54 (N.C.U.C., Aug. 7, 2023).

NRLP's Green Power program has saved the utility over a million dollars by functioning as a hedge against volatile natural gas prices, tr. vol. 3, 131-132, but it has not resulted in new clean energy or carbon emissions reductions. Through the Green Power rider, Rider RER, customers can purchase credits from zero-emissions hydroelectric energy. Tr. vol. 4, 115-116. NRLP has offered the program as a way for customers to "go further toward emission reductions," tr. vol. 4, 116, and the intention is good. But there is no evidence that purchases through the Green Power program have caused new hydro power to come online or prevented it from going offline, tr. vol. 4, 137-138, meaning it is not clear that purchasing credits through the Green Power program truly reduces pollution at all. NRLP has found that although two thirds of its customers claimed in a survey that they would be willing to purchase renewable energy at a premium if offered, less than 3% of NRLP's customers signed up for the Green Power program, and concluded that "indication of a desire of a program offered in a survey does not necessarily mean that there will be a subscription if offered, especially if there is an additional cost." Tr. vol. 4, 117. NRLP has not considered that its customers might be willing to pay more for access to renewable energy only if they are confident that it reduces emissions. Tr. vol. 4, 140.

NRLP could develop EE/DSM programs. Witness Miller gave two reasons NRLP has not done so: it does not have the staffing and resources to develop the programs, and it is not eligible for the statutory EE/DSM cost-recovery mechanisms. Tr. vol. 4, 110. NRLP will pursue EE/DSM programs only to the extent that it can obtain outside funding and support from third parties. Tr. vol. 4, 112.

But NRLP could overcome these obstacles readily. First, as for the resources to develop the programs, the programs it has begun to consider are a good start, tr. vol. 2, 94, and with its unusual customer base it has the opportunity to develop interesting behavior-based programs to reduce peak demand, tr. vol. 2, 91-92, 96-97. NRLP need not navigate uncharted waters; many nonprofit utilities in North Carolina have developed EE/DSM programs NRLP could draw from. Tr. vol. 4, Ex. JWH-2. NRLP should first develop a basic EE/DSM program plan to help determine which programs to pursue. Tr. vol. 2, 94-96. For all this, NRLP could draw on the resources of its parent institution ASU, which has economics and building science departments familiar with designing these programs even if they might not have done so yet. Tr. vol. 2, 136-137. Furthermore, other academic and nonprofit institutions likely would be eager to help NLRP if it asked—which it appears not to have done.

Second, it will be up to the Commission's determination, but NRLP likely could recover the costs of EE/DSM programs through rates. NRLP's legal counsel is correct that the EE/DSM statutes, G.S. §§ 62-133.8 and 62-133.9, do not apply to NRLP. Tr. vol. 4, 110. But that simply means that NRLP is not *required* to comply with those statutes. After NC passed Senate Bill 3 establishing REPS, ASU, among others, argued that it was exempt from the REPS requirement in G.S. § 62-133.8. The Commission agreed, noting that it had previously held that ASU and WCU were not public utilities. Order on Public Staff's Motion for Clarification, *In the Matter of Rulemaking Proceeding to Implement Session L. 2007-397*, Docket No. E-100, Sub 113, 2009 WL 1726236 (N.C.U.C. June 17, 2009).

But in the next breath, the Commission encouraged ASU and WCU to voluntarily comply. *Id.* Voluntary compliance would include making use of the cost-recovery mechanisms in G.S. §§ 62-133.8(h) and 62-133.9(d). It would be strange for the NCUC to recommend that NRLP voluntarily comply with the REPS but hold that NRLP could not avail itself of the cost-recovery mechanisms that the law provides. *See* G.S. § 62-133(a); *Cooper*, 366 N.C. at 494, 739 S.E.2d at 547 (discussing "twin goals" of G.S. § 62-133).

Furthermore, NRLP has voluntarily complied with statutes governing public utilities and voluntarily developed riders. Witness Halley testified in this rate case that NRLP's Schedule NBR was designed following the criteria in the net metering statute (G.S. § 62-126.4), tr. vol. 4, 232, even though the statute applies only to electric public utilities, G.S. § 62-126.4(a). And NRLP successfully (and voluntarily) proposed a voluntary renewable energy rider recently. Order Approving Renewable Energy Rider, *In the Matter of Petition of Appalachian State Univ., d/b/a New River Light & Power Co. for Approval of Renewable Energy Rider*, Docket No. E-34, Sub 52, 2021 WL 3422438 (N.C.U.C. July 19, 2021). NRLP developed this rider in response to customers' demands for access to renewable energy as expressed in their responses to a customer survey, not a legal requirement. Petition for Approval of Renewable Energy Rider 1-2, *In the Matter of Application of Appalachian State University, d/b/a New River Light and Power, for Approval of a Renewable Energy Rider ("Rider RER")*, Docket No. E-34, Sub 52 (N.C.U.C. July 6, 2021).

In the alternative, NRLP could recover its EE/DSM costs through rates in a general rate case, without making use of the statutory EE/DSM cost recovery mechanism. NRLP is subject to the Commission's general oversight over its rates. UNC institutions operating power plants and distribution systems, such as NRLP, after furnishing power to the institution, may sell excess power to the "people of the community at a rate or rates approved by the Utilities Commission." G.S. § 116-35. "Rate" is defined broadly in North Carolina law and includes any "tariff." G.S. § 62-3(24). Any EE/DSM riders NRLP proposed would be part of the "rate or rates approved by the Utilities Commission," G.S. § 116-35, making it proper for the Commission to consider it in this general rate case. Furthermore, the NCUC has some discretion over the scope of a rate case. G.S. § 62-137; see G.S. § 62-30 (general powers).

Accordingly, there are resources available to NRLP to help develop its EE/DSM programs, and once it does so it can recover its costs either through voluntary compliance with the EE/DSM statutes, or through a general rate case such as this one. Considering NRLP's investment in AMI, and now a new SCADA system to make use of the AMI, and the uninspiring programs resulting from NRLP's investments to date, the Commission should require NRLP to formally propose the programs that it has discussed to date, plus a behavior-based program, as pilots, and to develop an EE/DSM program plan. *See* tr. vol. 2, 96-97.

6. Conclusion

For the forgoing reasons, the Commission should:

(1) With respect to the rate of return:

a. reject the Stipulation,

b. adopt App Voices' cost of capital proposals, and

c. require New River to:

i. conduct a discounted cash flow (DCF) analysis to optimize its capital structure, and

ii. submit a compliance filing that reflects that analysis and any revised cost of capital figures that flow therefrom;

(2) Approve Schedule NBR, with the following modifications:

a. eliminate the SSC, which is unnecessary and based on flawed calculations, and

b. remove the annual "reset" erasing customer-generators' accrued excess generation credits, or at a minimum allow customers to choose their "reset" dates;

(3) Deny NRLP's proposal to increase the BFC, and instead authorize a BFC of no more than $10.61 per month;

(4) Direct NRLP to formally propose the EE/DSM programs that it has discussed to date, plus a behavior-based program, as pilots, and to develop an EE/DSM program plan.

Respectfully submitted this the 21st day of August, 2023.

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CERTIFICATE OF SERVICE

I certify that all parties of record have been served with the foregoing filing either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 21st day of August, 2023.

/s Nicholas Jimenez

Nicholas Jimenez