BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1276

In the Matter of:	)	**POST HEARING BRIEF OF NORTH**
	)	**CAROLINA JUSTICE CENTER,**
Application of Duke Energy	)	**NORTH CAROLINA HOUSING**
Carolinas, LLC for Adjustment of	)	**COALITION, SOUTHERN**
Rates and Charges Applicable to	)	**ALLIANCE FOR CLEAN ENERGY,**
Electric Service in North Carolina	)	**NATURAL RESOURCES DEFENSE**
and Performance-Based Regulation	)	**COUNCIL, AND VOTE SOLAR**

PURSUANT to North Carolina Utilities Commission (NCUC or Commission) Rule R1-24 and the instructions of the Chair at the close of the evidentiary hearing in this matter on September 5, 2023, the North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, Natural Resources Defense Council, and Vote Solar (NCJC, *et al*.), respectfully submit this brief to the Commission on certain issues in the above-captioned docket.

INTRODUCTION

Under N.C. Gen. Stat. § 62-133.16, an electric public utility filing a performance-based regulation (PBR) application has the burden of proving that the application would result in just and reasonable rates, is in the public interest, and is consistent with PBR statutory criteria and the Commission's PBR rules. Duke Energy Carolinas, LLC (DEC) has not met its burden of proof. It seeks approval for billions of dollars to continue its old Power/Forward and Grid Improvement Plan projects, which have been roundly criticized by stakeholders and met with skepticism from this Commission over the last six years. Tr. vol. 15, 850, 861-63. DEC has not shown that this inflated level of capital spending would deliver sufficient customer benefits to justify the cost. DEC has also failed to present enough evidence that this spending is sufficiently tied to the Carbon Plan or to other compelling North Carolina policy goals.

There is a substantial risk that these costly grid investments will fail to advance the deployment of additional distributed energy resources and crowd out the capital investments that DEC will need to make to accelerate retirement of fossil fueled generation assets and deploy replacement resources that comply with the carbon reduction requirements in HB 951. Tr. vol. 12, 905-06. When considered in tandem with DEC's planned non-MYRP capital spending over the next three years, DEC customers can expect significantly higher rates after the MYRP period concludes. Tr. vol. 14, 230. The substantial spending for distribution grid projects outside of the MYRP also risks foreclosing any benefits to customers from the earnings sharing mechanism. *Id*. at 230-31. That many of these capital investments would be subject to DEC's proposed 10.4% return on equity (ROE), which is 70 basis points more than an already inflated electric industry average, is further insult to injury. Tr. vol. 14, 21.

It is imperative that the Commission reject DEC's PBR application. If the Commission were to approve a multi-year rate plan (MYRP), it should incorporate NCJC, *et al*. witnesses Gennelle Wilson, David Hill, and Jake Duncan's proposed modifications. Specifically, the Commission should adopt witness Wilson's performance incentive mechanism (PIM) modifications and her alternative PIM proposals, approve witnesses Hill and Duncan's proposed non-wires alternative (NWA) demonstration projects, and require DEC to modify its MYRP distribution system investments to incorporate potential federal tax savings.

In addition, the Commission should initiate an investigation into distribution system planning to establish stakeholder supported modifications to DEC's distribution planning framework, require DEC to track system reliability at the zip-code or census-tract level, adopt witnesses Hill and Duncan's other recommendations to improve DEC's distribution system planning, spending, and stakeholder engagement, convene a policy goals docket to support the development and refinement of robust PBR policy goals, and require an independent management audit and financial audit.

Finally, regardless of the Commission's decision on the PBR application, the Commission should reject DEC's excessive proposed return on equity (ROE) proposal. Instead, the Commission should adopt the recommendation of NCJC, *et al*. witness Mark Ellis, who has demonstrated that authorized ROEs for electric public utilities have drifted out of sync with the actual cost of equity. His approach, using unbiased assumptions and inputs, results in an estimated cost of equity of 6.15%, optimized with an equity ratio of 58.88%, which would allow DEC to maintain its current bond rating, fairly compensate DEC's equity investors, and result in substantial savings for DEC's customers, $520 million below DEC's initially proposed revenue requirement. At a minimum, even if the Commission does not adopt witness Ellis's recommendation, the Commission should consider his well-founded critiques of DEC witness Roger Morin's assumptions and model inputs when setting the lowest possible authorized ROE. It also is important to remember that over the last few decades, witness Morin's recommended ROEs have been, on average, 100 basis points above what commissions ultimately approved in electric public utility rate cases. DEC has provided no reason why this Commission should be the first one to accept his recommended ROE.

As further protection for DEC's most vulnerable, low-income customers, NCJC, *et al*. urges the Commission to approve the Affordability Settlement, which is not contingent on the Commission approving the PBR application.

ARGUMENT

I. RATES SET BY THE COMMISSION MUST BE JUST AND REASONABLE.

In the Public Utilities Act, the North Carolina General Assembly declared that it is the policy of the state to provide "fair regulation of…utilities in the interest of the public" and "just and reasonable rates and charges for public utility services." In light of these core principles, the North Carolina Supreme Court has ruled that "[t]he primary purpose of [the Public Utilities Act] is…to assure the public of adequate service at a reasonable charge." *State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 285 N.C. 671, 680, 208 S.E.2d 681, 687 (1974).

In furtherance of this statutory purpose, the Commission is vested with the authority to set rates for public utilities consistent with the policies of the Act. N.C.G.S. § 62-2(b); *see State ex rel. Utils. Comm'n v. Edmisten*, 294 N.C. 598, 606-07, 242 S.E.2d 862, 868 (1978) (holding that the Public Utilities Act empowers the Commission to effectuate the public policies established by the Act).

In setting rates for public utilities, the burden of proof is on the utility to show that its proposed rates are just and reasonable. N.C.G.S. § 62-75; *State ex rel. Utils. Comm'n v. Cent. Tel. Co.*, 60 N.C. App. 393, 394, 299 S.E.2d 264, 265 (1983). The United States Supreme Court has held that "the fixing of 'just and reasonable' rates…involves a balancing of the investor and the consumer interests." *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603, 64 S. Ct. 281, 288 (1944). Consistent with the Supreme Court's command, the Public Utilities Act specifies that "the Commission shall fix such rates as shall be fair both to the public utilities and to the consumer." N.C.G.S. § 62-133(a). This provision of the Act "emphasize[s] that fairness to customers is a critical consideration in rate cases by including a directive that 'the Commission shall fix such rates as shall be fair both to the public utilities *and to the consumer*.'" *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 495, 739 S.E.2d 541, 548 (2013) (emphasis in original) (quoting N.C.G.S. § 62-133(a)). Accordingly, the Commission must consider the impact on customers in determining whether DEC's proposals to increase its rates and charges in this case are just and reasonable.

With respect to PBR applications, the applicant utility must demonstrate that its proposed PBR mechanisms "would result in just and reasonable rates, is in the public interest, and is consistent with the criteria established in [HB 951] and rules adopted thereunder." N.C.G.S. § 62-133.16(d)(1). In reviewing a PBR application, the Commission must determine whether the application does the following: (1) "[a]ssures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric public utility and to the customer"; (2) "[r]easonably assures the continuation of safe and reliable electric service"; and (3) "[w]ill not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or 'rate shock' to customers." *Id.*

II. THE COMMISSION SHOULD REJECT DEC'S EXCESSIVE DISTRIBUTION SPENDING OVER THE NEXT THREE YEARS AND REQUIRE MORE ROBUST CONSIDERATION OF LESS EXPENSIVE NON-WIRES ALTERNATIVES AND THE ENVIRONMENTAL JUSTICE AND BILL AFFORDABILITY IMPLICATIONS OF ITS GRID PLANNING.

DEC's proposed distribution grid projects are unreasonably expensive, outdated, and ill-conceived. The Company's plan, which is largely a continuation of its old Power/Forward and Grid Improvement Plan (GIP) initiatives, costs nearly $6 billion, disregards less expensive non-wires alternatives (NWAs), and fails to meaningfully consider the environmental justice implications of its proposed projects. The Commission not only has the authority to reject DEC's unreasonable and imprudent plans, but it also has the obligation to do so.

NCJC, *et al*. recommend that the Commission reject DEC's MYRP application and open an investigation into distribution system planning with stakeholder input to determine: (1) grid modernization objectives, (2) reporting and data sharing requirements; (3) NWA methodology and proposal requirements; (4) a community engagement plan; and (5) environmental justice aspects of grid modernization. Tr. vol. 15, 863, 875-77.

A. DEC's Proposed Distribution Grid Plan Is Unreasonably Expensive.

Over the next three years, DEC intends to spend $5.883 billion on distribution capital projects, accounting for roughly 45% of all MYRP and 50% of all non-MYRP project expenditures—by far the single largest capital spending item in DEC's rate case application. Tr. vol. 12, 894-96. Significantly, that amount does not include the $2.329 billion DEC spent on distribution capital in the base general rate case.[1] *Id*. at 858, Figure 20. Worse still, the actual costs could be even larger, given that cost estimates for MYRP projects in DEC's initial application were stale, and the Company's mid-rate case update "created challenges" that failed to fully allay the Public Staff's concerns over DEC's

[1] Distribution plant spending accounts for 35% of total capital spending in the base general rate case. Tr. vol. 12, 894.

outdated estimates. *Id*. at 870. Even if DEC's cost estimates were correct, however, they still would be unjustifiable.

Public Staff witness Dustin Metz noted with concern that DEC's planned non-MYRP capital spending over the next three years is "staggering" and will result in continued steep rate increases when Duke returns for another rate case in three years. *Id*. at 934-35. In addition, this unprecedented level of capital spending—from both MYRP and non-MYRP projects—does not include investments that will be required under the Carbon Plan, which means an even larger amount of capital expenditures is likely looming in 2027 through 2030. *Id.* at 905-06.

DEC's enormous spending on distribution grid projects is nothing new. From 2019 to May 2023, nearly $5 billion of DEC's total capital spending was on distribution grid projects. *Id*. at 904, Figure 35. During a similar timeframe, from June 2020 to April 2023, distribution capital expenditures made up the single largest category of DEC's capital spending—35% of the total. *Id*. at 894, Figure 24.

What is worse, the distribution projects that DEC spent billions of dollars pursuing during the past several years are substantially similar to the distribution projects that the Company plans to spend *even more money* pursuing during the MYRP period. The Commission should act now to stop Duke from continuing its unreasonable and imprudent plans, which threaten to further increase the pace of significant rate hikes.

B. <u>DEC's Proposed Plan Is Outdated.</u>

Most of the distribution grid projects that DEC is seeking to include in rate base are continuations of the Company's outdated Power/Forward and Grid Improvement Plan (GIP) projects—suggesting that DEC failed to meaningfully consider significant changes in state policy, including the carbon reduction requirements under HB 951, as it developed its grid modernization plans. *See* tr. vol. 15, 840, 862-63.

Ever since Duke announced its $13 billion Power/Forward initiative for grid spending in 2017, the Company's plans have been met with near universal skepticism—if not outright condemnation. For example, the Public Staff and intervenors noted significant concerns with DEC's request for a Grid Reliability and Resilience Rider (Grid Rider) or deferral accounting treatment for Power/Forward. *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction*, In the Matter of Application by DEC for Adjustment of Rates and Charges, Docket No. E-7, Sub 1146 (Jun. 22, 2018) (hereinafter Sub 1146 Order). These intervenors noted several problems with DEC's plans for advanced cost recovery or deferral accounting treatment for Power/Forward, including that grid spending plans were part of Duke's general obligation to provide reliable service to customers, shifted risk from the Company to customers, would eliminate DEC's incentive to prudently manage costs, and were too expensive in relation to the purported benefits. Sub 1146 Order at 133-37 (summarizing testimony from the Public Staff, CIGFUR, CUCA, EDF, Kroger, NCSEA, and Tech Customers that recommended the rejection of the Grid Rider or deferral accounting treatment). The Commission took note of evidence demonstrating that Duke's Power/Forward plan was designed to drive earnings growth for Duke's shareholders. *Id.* at 129, 136. The Commission concluded[2] "that several of the intervening parties have raised valid concerns regarding the need for additional transparency and detailed information regarding Power[/]Forward" and directed Duke to collaborate with stakeholders to address the substantive issues that were brought up relating to Power/Forward. *Id.* at 149.

Shortly thereafter, Duke rebranded Power/Forward as the GIP. Tr. vol. 15, 862. About 80% of the Company's GIP filing in 2019 comprised programs described in the Power/Forward proposal. Similar to its development of Power/Forward, Duke failed to meaningfully consider stakeholder feedback. Even though the Company held stakeholder meetings, many participants expressed concerns about the stakeholder engagement process—namely, that Duke had already established its fundamental goals and grid projects *before* engaging with stakeholders, providing little opportunity for stakeholders to meaningfully influence Duke's plans. *Id*. at 840.

Now, even though North Carolina has adopted the carbon reduction requirements under HB 951, DEC largely plans to continue with its outdated Power/Forward and GIP projects without any significant course correction. *Id*. at 862-63. Witnesses Hill and Duncan found that nearly 60% of DEC's proposed distribution grid spending supports the continuation of Power/Forward or GIP projects. *See id*. at 850. The considerable overlap between the Company's

[2] Because Duke was not seeking cost-recovery for Power/Forward in the 2017 rate case, the Commission was not in a position to rule on the reasonableness or prudence of the Company's plan.

distribution projects in this case and those it pursued under Power/Forward and GIP indicate that most of DEC's proposed projects are outdated and fail to adequately reflect best practices or stakeholder input. Notably, when asked how the Company had changed the substance of its grid modernization plan in response to stakeholder feedback, it could only identify a few changes. Tr. vol. 8, 420-21.

The carbon reduction mandates of HB 951 will require significant levels of capital investment from the Company in the coming years. Rather than investing in renewable resources now, Duke proposes to spend billions of dollars on discretionary grid improvements of dubious value. The principal benefits Duke uses to justify its billions of dollars in capital spending are reliability improvements. Tr. vol. 15, 849. But—consistent with its mandate to provide service—Duke claims to provide adequate levels of reliability already.[3] Public Staff witness Dustin Metz summed up the crux of the issue in his direct testimony: "It is shocking that maintaining or improving the overall reliability of the Company's entire electric system requires nearly a $12.2 billion dollar capital project spend by…December 2026." Tr. vol. 12, 905. Even though witness Metz's statement applies to all of DEC's planned capital spending concerning reliability, distribution spending is by far the single biggest component of that massive estimate. *Id*. at 896, Figure 28. Any potential benefits from additional reliability improvements would be marginal at best—and not worth the exorbitant cost, which residential customers would disproportionately bear. Tr. vol. 15, 860.

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[3] The Company continues to "affirm[] that it is maintaining adequate, reliable service for its customers." Tr. vol. 15, 849.

Even the marginal benefits that DEC identified are most likely inflated. Witnesses Hill and Duncan noted significant problems with the Company's cost-benefit framework. *Id*. at 857-61. First, the anticipated reduced outage benefits of each program are considered in isolation, meaning benefits from one program are considered as if Duke were not pursuing other distribution grid investments simultaneously, resulting in potential double-counting. *Id*. at 858-59. Second, DEC's cost-benefit framework fails to weigh the rate impact that residential customers will endure under the Company's enormous spending plan, compared to the non-monetary benefits of marginally reduced outages for those customers, who will shoulder a disproportionate burden of cost-recovery for distribution grid projects. *Id*. at 859-60. Third, DEC's plan fails to consider the potential for third-party NWAs to defer or completely avoid the need for some of the Company's proposed grid projects—not to mention, some of those customer-sited investments could result in customer bill savings, as well. *Id*. at 860. Fourth, DEC's plan fails to consider the impact of IRA incentives that make customer-sited investments much more affordable and put downward pressure on rates overall. *Id.* at 860-61.

In short, DEC has overestimated the potential benefits and underestimated the potential costs of its distribution grid plan to justify its massive spending proposal. To help remedy these shortcomings, the Commission should convene a working group to consider a more comprehensive cost-benefit framework, drawing from the National Energy Screening Project. *Id*. at 861.

C. **<u>DEC's Plan Is Infeasible, Relies on Arbitrary "Megatrends" to Justify Its Outdated Projects, and Fails to Consider Less Costly Alternatives.</u>**

The Public Staff expressed serious reservations about DEC's ability to meet necessary staffing levels to complete its proposed MYRP projects, without relying on the outside market, which would potentially expose DEC and its customers to increased cost and execution risks. Tr. vol. 12, 906-09. Witness Metz testified that he "find[s] it alarming that a capital plan...which includes such significant MYRP and non-MYRP capital spend and a large number of projects[] does not have a commensurate staffing plan to complete the work." *Id*. at 909. In a similar vein, intervenors had insufficient time to thoroughly vet DEC's many distribution grid projects. As explained by Public Staff witness James McLawhorn, DEC's PBR application effectively combines four rate cases into one, but the Public Staff and intervenors had only thirty additional days to review the Company's application.[4] *Id*. at 950-51.

Furthermore, DEC arbitrarily relies on so-called "megatrends" to justify its continuation of Power/Forward projects under the GIP banner. Tr. vol. 15, 854-57. The Company, however, has failed to consider a host of other important trends that have major implications for DEC's distribution grid planning—including trends that could reduce execution risks and costs. For example, DEC treats "the growth of [distributed energy resources (DERs)] as a negative impact, for which the sole solution is direct utility investment to enhance grid capabilities," overlooking the

[4] Since numerous distribution grid projects comprise nearly half of DEC's proposed capital spending—for general rate case, MYRP, and non-MYRP projects—there was insufficient time and staff resources for the Public Staff or intervenors to sufficiently scrutinize DEC's application.

"value to the system and to customers of a more integrated and holistic approach to grid planning based on a more balanced portfolio of utility and customer sited assets." *Id*. at 858.

Under Megatrend 2, DEC witness Brent Guyton describes additional DERs on the grid as "new types of load and resources impacting the grid." *Id*. at 855. DEC's phrasing suggests that DERs create an additional need for traditional grid investments, even though a planned combination of DERs—such as customer-sited solar paired with storage, energy efficiency, and demand flexibility—would in fact help to "reduce circuit level capacity constraints and serve as a system level asset." *Id*.

Similarly, under Megatrend 3, witness Guyton suggests that public and private incentives and requirements for clean energy resources are driving additional system costs. *Id*. at 855-56. But that is because DEC's grid plans consider only *utility-owned* assets rather than third-party assets that could provide grid services at lower cost. *Id*. at 856. Furthermore, under Megatrends 5 and 7, witness Guyton ignores the ways in which NWAs, DERs, and vehicle electrification could be used to lower costs and benefit ratepayers. *Id*. at 856.

DEC's attempts to cast DERs in a negative light are particularly troubling, given the Public Staff's concerns about the Company's fossil-fueled resources: "the Company's fossil generating fleet performance [natural gas and coal] has degraded (trended negatively) over the last decade…. Should these negative trends continue, they may further impact reliability or the ability to perform daily economic dispatch." Tr. vol. 12, 845.

Significantly, DEC's megatrends do not include one of the most significant trends in recent years—that of federal and state governments tracking the distributional effects of their policies to ensure that environmental justice communities receive an equitable share of associated benefits. Tr. vol. 15, 857. In fact, DEC's proposed plans fail to meaningfully consider environmental justice at all.

Finally, DEC's plan completely disregards less costly alternatives. In particular, the Company fails to reasonably consider NWAs, especially multiple DER alternatives, for any of its distribution grid upgrades.[5] Instead, it arbitrarily establishes a single test for batteries, which is the sole possible NWA that DEC will consider. *See id.* at 864. DEC did not develop this approach with any stakeholder feedback, despite multiple efforts by stakeholders to engage on a shared NWA methodology since the initial Power/Forward meetings. *Id*. at 863-64.

Due to its unnecessarily limited screening of NWAs, DEC ignores a range of more cost-effective NWA options that could leverage energy efficiency and demand response, while also helping to lower customer bills. *See id*. Furthermore, as NCJC, *et al*. witness Wilson notes, the PBR components of DEC's application do not go far enough to adequately incentivize cost-effective NWAs and thereby

[5] The testimony of NCJC, *et al.* witnesses Hill and Duncan demonstrates that there are likely more cost-effective ways for DEC to transform its grid to accommodate more distributed generation, electric vehicles, and comply with carbon plan requirements.

overcome the regressive cost-of-service incentives that North Carolina's PBR regulatory regime substantially preserves.[6] *Id*. at 893-99.

NCJC, *et al*. asks the Commission to (1) direct DEC to collaborate with stakeholders on an updated NWA methodology and (2) order DEC to conduct two or more NWA demonstration projects, at least one of which should be located in an environmental justice community to evaluate how targeted intervention and leveraging of multiple DERs can achieve grid and societal objectives simultaneously. *Id.* at 876.

D. DEC Failed to Consider the Relationship between Its Proposed Distribution Grid Spending and Environmental Justice.

DEC has failed to meaningfully consider the extent to which its distribution grid plans could exacerbate problems related to energy affordability and equity. In particular, DEC has not seriously evaluated the potential for its distribution grid expenditures to intensify the energy burdens of low- and fixed-income customers, especially those who are unable to take advantage of bill payment assistance programs. *Id*. at 866, 874-75. Furthermore, DEC has failed to examine whether its grid improvement projects are equitably benefiting ratepayers along racial or income lines.[7] *Id*. DEC's plan has major implications for a host of environmental justice concerns. Witnesses Hill and Duncan identified two specific areas—

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[6] Simply put, DEC's capital spending inordinately serves as a vehicle to increase potential for shareholder returns. Nothing in the pending PBR application serves as an adequate check on that incentive.

[7] To the extent its GIP-related projects are improving system reliability, DEC has not tracked which communities are receiving those benefits and which are not. Without some kind of geographic analysis of those investments, neither the Commission nor DEC can track whether communities of color or low-income households are being disproportionately left out of sharing in those improvements.

service reliability and hosting capacity—where the Company can address energy inequity now.

1. Equity in Service Reliability.

Providing reliable service is one of the basic tenets of the regulatory compact. If certain communities within the Company's service territory are experiencing disproportionately high reliability events, the Commission and the Company have a responsibility to mitigate these problems. *Id*. at 867. Tracking reliability data at a level more granular than the system can assist the Company in reprioritizing its infrastructure spending and developing new programs to address inequity in reliability. *Id*. Significantly, DEC *already* tracks reliability data at a level more granular than the system. The Company tracks outage history, for example, "down to the protective device level" for every circuit in the Carolinas. *Id*. at 867-68. So far, however, the Company has refused to report that data. And as a result, the Commission and stakeholders have no way to assess "whether certain communities might experience more frequent or longer outages" than others. *Id*. at 867.

In contrast, public utilities in Illinois and Michigan track grid reliability at the circuit and substation level. *Id*. They perform environmental justice analyses by mapping census tract-level data onto demographic data. *See id*. In a DTE Electric rate case in Michigan, for example, evidence indicated that environmental justice communities disproportionately experienced worse grid reliability than other communities in the state. *Id*. at 867-69, 874-75. Based on this information, the Michigan Public Service Commission (PSC) ultimately approved a new reliability reporting template, incorporating circuit, zip-code, and census tract-level reporting. *See id.* at 867, 868-69. With this data, the PSC and DTE can tailor grid investments to help ensure more equitable outcomes. There is no reason why DEC could not do the same.

Unfortunately, however, DEC does not report any data that would indicate whether there are racial or income disparities in its North Carolina service territory. *Id*. at 867-68, 874-75. The Commission should direct DEC to report reliability data not just at the system-wide level but also at the census tract and zip-code level. *Id*. at 871. The Company and stakeholders could then map the geographic data onto sociodemographic factors, such as race and income, to determine whether disparities in reliability exist. *See id*. at 871-72. Given the relationship between DEC's grid modernization efforts and its obligations under the Carbon Plan, such geographic analysis seems particularly valuable, as "[s]uccessful execution of the Carbon Plan requires engagement by Duke on issues related to environmental justice and with frontline communities." *Order Adopting Initial Carbon Plan*, Docket No. E-100, Sub 179, at 42 (Dec. 30, 2022).

2. Equity in Hosting Capacity.

Evidence from other jurisdictions also suggests that low-income communities and communities of color experience disparities in hosting capacity. *See* tr. vol. 15, 869, 872. An effective *generation* hosting capacity analysis would provide DEC and stakeholders with more insight into whether specific circuits could manage DER without additional investments. Relatedly, an effective *load* hosting capacity would measure the ease with which individual circuits could serve electricity demand without additional investments. DEC should work with stakeholders to improve its hosting capacity analysis, overlay sociodemographic, energy burden, and other environmental justice indicators on its planned grid hosting capacity (GHC) map, and include load hosting capacity in its GHC analysis. *Id*. at 872.

The Company's current approach to GHC analysis is unlikely to reveal whether hosting capacity disparities exist in DEC's service territory. *Id*. at 869-71. To rectify this issue, DEC should adopt the fourteen key decision point framework that the Interstate Renewable Energy Council (IREC) developed and collaborate with stakeholders in using that framework to evaluate and improve DEC's GHC analysis. *Id*. at 872. At a minimum, such improvements should include incorporating sociodemographic, energy burden, and other environmental justice indicators in DEC's GHC map and incorporating load hosting capacity with generation hosting capacity in its GHC analysis. *Id*. Improving hosting capacity would significantly benefit environmental justice communities by supporting DER projects, such as community solar.

In sum, to account for environmental justice considerations in DEC's distribution grid planning, the Commission should require the Company to:

- Report reliability data at the census tract and nine-digit zip-code level—comprised of aggregated and anonymized customer premise level data—in order to investigate potential disparities in reliability services.
- Include geographic reliability data as a tracking metric in the PBR application.
- Propose a PIM in its next PBR application focused on improving reliability in the census tracts experiencing lower reliability metrics.

- Use its existing GHC stakeholder process to evaluate IREC's fourteen decision point framework for establishing an effective hosting capacity analysis.

- Collaborate with stakeholders to overlay sociodemographic, energy burden, and other environmental justice indicators on its planned GHC map.

- Include load hosting capacity with generation hosting capacity in its GHC analysis.

Id. at 871-72, 874-77. If done well, grid modernization projects "can facilitate the integration of DERs and lower the overall cost of" complying with the carbon reduction mandates of North Carolina law. *Id*. at 844. But if done poorly, those grid spending projects "may increase…compliance costs without delivering comparable benefits to ratepayers." *Id*. DEC has done poorly. Its distribution grid spending plan fails to put North Carolina on a path towards least-cost Carbon Plan compliance and largely ignores the potential impact of its proposed projects on environmental justice communities.

It is difficult to imagine any context in which such an unreasonable and imprudent distribution spending plan would survive the Commission's scrutiny. If Duke proposed to build a power plant, for example, with capital costs of $1 billion, the proposed project—a substantial investment—would be subject to meaningful review during a Certificate of Public Convenience and Necessity (CPCN) proceeding. For the projects within DEC's multi-billion-dollar distribution grid plan, however, there will be no CPCN proceedings. *This* proceeding is the Commission's opportunity to require DEC to course correct. And ratepayers, who face substantial cost impacts, are counting on it.

III. THE COMMISSION SHOULD APPROVE THE AFFORDABILITY SETTLEMENT.

In light of the substantial, unjustified spending in DEC's PBR application, it is even more important that the agreement and stipulation of partial settlement regarding low-income/affordability performance incentive mechanism and affordability issues (Affordability Settlement) entered into between NCJC, *et al*., Sierra Club, DEC, Duke Energy Progress (DEP), and the Public Staff be approved.

In short, the Affordability Settlement would require the withdrawal of DEC's Low-Income/Affordability PIM; the disbursement of $16 million in aggregate DEC and DEP shareholder contributions over three years, $10 million of which would support health and safety repairs and $6 million of which would support bill payment assistance through the Share the Light Fund; tracking and reporting how the health and safety repair funds are used; tracking and reporting residential customer payments; the establishment of DEC's proposed Customer Assistance Program (CAP) as a three-year pilot; and stakeholder collaboration between the stipulating parties and intervenors to determine whether the CAP pilot could be transitioned into a tiered discount affordability program. Tr. vol. 11, 74-77.

The Affordability Settlement strikes a fair and appropriate balance in resolving the Company's Low-Income/Affordability PIM, affordability PIM tracking metrics, and CAP. The proposed shareholder contributions will provide bill payment assistance and help unlock additional bill savings for low-income customers by facilitating the home repairs needed to qualify those customers for weatherization assistance. *Id.* The proposed tracking and reporting requirements will help quantify the number of home repairs and energy burden reductions attributable to this health and safety repair assistance. *Id.*

In addition, the CAP pilot would provide monthly bill payment assistance to approximately 64,000 low-income DEC customers who receive or have been approved to receive Low Income Energy Assistance Program or Crisis Intervention Program assistance. *Id*. at 115. Participants in the CAP Pilot will also be referred to no-cost energy efficiency and weatherization programs to identify potential savings opportunities that would reduce their usage, saving participating customers money on their bills. *Id*. at 102-03. The stipulating parties commit to exploring the benefits and feasibility of transitioning the CAP pilot into a tiered discount affordability program. *Id*. at 77, 103-04. The Commission has broad authority to advance generally applicable policy on affordability and energy burden reductions, and the Affordability Settlement advances these policy objectives while minimizing interclass subsidization to the greatest extent practicable by the end of the MYRP period by exerting downward pressure on all rates. *See id*. at 102.

Importantly, the Commission can accept the Affordability Settlement in its entirety as part of its base, general rate case decision while taking other actions to protect North Carolina ratepayers from unaffordable rates. The key levers at the Commission's disposal are setting an appropriate ROE and not allowing excessive levels of planned distribution spending by rejecting DEC's MYRP.

IV. THE COMMISSION SHOULD REJECT DEC WITNESS ROGER MORIN'S RETURN ON EQUITY PROPOSAL AND ADOPT NCJC, *ET AL*. WITNESS MARK ELLIS' PROPOSAL INSTEAD.

Notwithstanding the potential of the Affordability Settlement to bring significant relief to some of DEC's most vulnerable low-income customers, the Commission has a broader obligation to ensure affordable rates for all of DEC's customers. One of the most significant drivers of customer rates that is within the Commission's discretion is the allowed ROE. The Commission should reject DEC's proposed 10.4% ROE as unreasonable, excessive, and unsupported by the record. An allowed ROE that is based on actual investor return expectations for investments of commensurate low risk can be substantially lower than DEC's proposal, saving DEC's customers hundreds of millions of dollars without damaging the Company's credit rating or ability to attract capital.

A. Applicable Legal Standards Require Setting the Lowest Possible Allowed Return on Equity While Still Being Fair to Investors.

Under Chapter 62, "the General Assembly conferred [on the Commission] '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)).

When it comes to setting the authorized return on equity, the Commission is required to "meet the twin goals of assuring sufficient shareholder investment in utilities while simultaneously maintaining the *lowest* possible cost to the using public for quality service." *State ex rel. Utils Comm'n v. Carolina Util. Customers Ass'n, Inc.*, 348 N.C. 452, 458, 500 S.E.2d 693, 698 (1998) (emphasis added). These twin goals for setting the authorized rate of return are set forth in the Public Utilities Act. N.C.G.S. § 62-133(b)(4) (providing that when the Commission fixes the ROE, it is required to consider the ability of the public utility to compete for capital on terms that are reasonable and that are fair to its customers and investors). "The 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)).

Being fair to investors, however, is not the same as guaranteeing current market prices for stocks in the parent company of a regulated public utility. "The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid." *Hope*, 320 U.S. at 601. Equity investors take the risk that a utility "might possibly at some time because of market conditions be required to issue shares at less than book value," and it is not the Commission's responsibility to protect investors from that outcome. *State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n*, 322 N.C. 689, 699, 370 S.E.2d 567, 573 (1988).

The Commission is “free, within the ambit of [its] statutory authority,” to make pragmatic adjustments when determining the lowest reasonable rate that would be fair to customers and investors. *Fed. Power Comm'n v. Nat. Gas Pipeline Co. of Am.*, 315 U.S. 575, 586 (1942). The Constitution does not bind the Commission “to the service of any single formula or combination of formulas.” *Id.* There is no mathematical formula that the Commission can rely on to produce a precise allowed ROE for DEC in this case. Instead, the Commission must use its own judgement to properly estimate the cost of equity capital that will fairly compensate investors, based on expectations for companies of commensurate risk profiles, while at the same time protecting customers from unreasonable rates. *See also State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n*, 322 N.C. at 697, 370 S.E.2d at 572 (setting the allowed ROE is “essentially a matter of judgment based on a number of factual considerations which vary from case to case”).

In this case, DEC has not met its burden of proof to justify its requested 10.4% authorized ROE with a capital structure of 53% equity*. See generally State ex rel. Utils. Comm'n v. Duke Power Co.*, 285 N.C. 377, 389, 206 S.E.2d 269, 277–78 (1974) (“the burden is upon Duke to establish the reasonableness of the rate increases it has proposed”); N.C.G.S. §§ 62-75; 62-134(c). To support its claim that a 10.4% ROE is the lowest figure that would satisfy the needs of investors under applicable legal standards, DEC relied on the testimony of Dr. Roger Morin. His estimate of the cost of equity, however, rests on assumptions that unreasonably bias his results upwards. Just as importantly, witness Morin ignores the reality that investors are generally expecting lower returns from the equity markets than he asserts that they would "require" from public utility stocks, which are less risky than the equity markets generally. Finally, witness Morin's testimony is plagued by inconsistencies and contradictions with his published work that undercut the credibility of his recommended ROE.

As a witness for regulated electric public utilities before state public utility commissions over the last few decades, witness Morin has recommended unreasonably high ROEs. The ultimate allowed ROE set by those commissions is, on average, 100 basis points lower than witness Morin's original recommendations. Witness Morin presented no evidence that the resulting lower ROEs impacted the ability of those electric public utilities to obtain capital on reasonable terms or that their financial integrity had been impacted by those decisions.

Notably, witness Morin testified that any Commission-approved ROE within his recommended range of 9.8% to 10.9% would be reasonable. Tr. vol. 8, 80-81; vol. 7, 372. Removing the unwarranted 20-basis point flotation adjustment[8], the bottom of witness Morin's reasonable range is 9.6%. Authorizing a ROE above 9.6%—within what Duke's ROE witness has said is reasonable—is more than would be required under governing legal standards. *Hope*, 320 U.S. at 600-05. In addition, witness Morin testified that it would be reasonable to consider the lower end of his range for a utility that enjoys a full suite of risk mitigators, such as

[8] *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice*, In the Matter of Application of DEP for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and PBR, Docket No. E-2, Sub 1300, at 164-65 (Aug. 18, 2023).

multiyear rate plans and riders that allow for advanced cost recovery. If the Commission determines that Duke is less risky than the average utility, it would be appropriate to set an ROE at the low end of the range deemed reasonable by the Commission. Tr. vol. 8, 85. An authorized ROE at the low end of a reasonable range is not equivalent to a *reduction* in the allowed ROE due to risk mitigators such as MYRP and PBR. While the Commission is free under governing law to reduce the allowed ROE to account for the reduced risk to the utility from the approved MYRP, setting the ROE at the lowest end of a reasonable range is not the same as reducing the ROE below that range. N.C.G.S. § 62-133.16(c)(1)(a).

Intervenor evidence on the authorized rate of return and capital structure, particularly testimony offered by NCJC, *et al*., the Public Staff, and Carolina Utility Customers Association (CUCA), further demonstrates the unreasonableness of DEC's proposed 10.4% ROE. Based on a review of the complete record, a reasonable floor for the authorized ROE is 6.15%, which reflects the most accurate estimate of the actual cost of equity for enterprises of commensurate risk to DEC. Witness Ellis's recommended ROE would save DEC's customers $520 million each year (from DEC's original proposed revenue requirement), while allowing DEC to maintain its current A2 credit rating. Even if the Commission does not adopt witness Ellis's recommendation, it should nevertheless consider his unrebutted testimony on the systemic problem of authorized ROEs exceeding the cost of capital as well as his detailed assessment of the flaws and shortcomings with witness Morin's assumptions and model inputs when setting the allowed ROE for DEC.

B. Regulated Public Utilities' Allowed Returns on Equity Significantly Exceed the Cost of Capital.

The Commission's decision on authorized ROE has a substantial effect on the overall affordability of essential electric public utility service for DECs ratepayers. Under DEC's original application, its proposed combined rate of return on capital, grossed up for taxes, accounted for more than 30% of its revenue requirement. Tr. vol. 15, 692. If the Commission-authorized ROE is set at an amount that is greater than the actual cost of equity capital, wealth is transferred from ratepayers to shareholders. Tr. vol. 7, 429.

Witnesses Ellis and Morin agree that the authorized rate of return on equity should be set equal to the cost of equity capital. Tr. vol. 7, 429; tr. vol. 15, 696. Where they differ is on how to accurately estimate the cost of equity. And while witness Morin insisted that cost of equity is equal to the return on equity, the two figures are distinct in ways that can inform the Commission's analysis of the appropriate authorized ROE. Tr. vol. 7, 354. ROE is an accounting measure that can be reported on a company's financial statement and is equal to net income divided by the book value of equity. Tr. vol. 15, 697. Cost of equity, in contrast, must be estimated and is based on the returns investors expect from investments of commensurate risk. *Id.* Though witness Morin testified that he was astonished at witness Ellis's "comment" regarding the difference between "return on equity" as an accounting principle and "cost of equity" as an economic principle, he did not dispute any of the basic definitions used by witness Ellis to describe the difference between these concepts. Tr. vol. 7, 354; tr. vol. 15, 695-697.

This distinction matters in part because any model that purports to estimate the *cost* of equity based on historical or forecast utility *returns* on equity will lead regulators astray. Tr. vol. 15, 698-700. Those models—such as witness Morin's Risk Premium Methodology (RPM) that relies exclusively on historical utility returns and on authorized ROEs—"incorporate no information about the actual cost of equity" and "produce invalid results." *Id*. at 699. For any given company, the cost of equity and the return on equity may be the same numerical amount, but they will not necessarily equal each other at any given time.[9]

There is ample evidence that authorized ROEs for regulated electric public utilities have exceeded the cost of capital for decades. As shown below:

- Market-to-book ratios in the proxy group are about 2.0, direct evidence that the allowed ROEs for those companies exceed the cost of capital.
- Since the 1980s, the spread between authorized ROEs and the risk-free rate has widened substantially.
- Authorized ROEs are higher than expected returns from equity investments in the market as a whole, even though investors should expect lower returns from utility investments.

DEC witness Morin has provided no compelling reason for the Commission to disregard these key indicators that demonstrate the misalignment between authorized ROEs and the cost of equity.

[9] As witness Ellis explained, one possible source of the conflation between these concepts comes from finance professionals, who "commonly refer to the cost of capital as the expected return (on capital)." Tr. vol. 15, 698.

1. High Market-to-Book ratios for public utilities demonstrate that authorized returns on equity have exceeded the cost of equity capital.

Given the difference in book value and market value of the utilities in witness Morin's proxy group—as well as for DEC's parent company—it is apparent that expected ROE investments (i.e., the cost of capital) are less than currently authorized ROEs for public utilities. At market-to-book ratios near 2.0 (which is the case for the companies in witness Morin's proxy group), investors' expected returns are significantly lower than the returns on book equity. Tr. vol. 15, 703-08. Investors cannot buy securities at book value, but instead at market value. Paying more for a given stream of cash flows necessarily means that expected returns are lower. *Id*. at 716. Thus, the ROEs for utilities that have a market value that is, on average, twice book value, necessarily indicate that investors' *actual* ROE expectations are lower than the authorized ROE. *Id*. at 715-16. If the return on book value of equity is 10%, and an investor buys stock in that company at a market-to-book ratio of 2.0, then the actual return that investor expects on the equity investment is 5%.

As witness Ellis noted, a reasonable rule of thumb equates the market-to-book ratio—on one hand—to the ratio of ROE to cost of equity—on the other—which would imply that the average cost of equity for the proxy group is approximately 5.5%. *Id*. at 706-07. Put another way, for every dollar of equity that a utility invests when its market-to-book ratio is greater than one, its shareholders receive not just a reasonable return, but additional value beyond the cost of capital. *Id.* at 707. That additional value comes at ratepayer expense.

In his book *New Regulatory Finance*, witness Morin has acknowledged that when the ROE is equal to the cost of equity, the market-to-book ratio of a utility will approach 1.0:

> In Chapter I, it was suggested that if regulators set the allowed rate of return equal to the cost of capital, the utility's earnings will be just sufficient to cover the claims of the bondholders and shareholders. No wealth transfer between ratepayers and shareholders will occur.
>
> The direct financial consequence of setting the allowed return on equity, *r*, equal to the cost of equity capital, *K*, is that share price is driven toward book value per share, at least in theory under ideal conditions. Intuitively, if r>K, and is expected to remain so, then market price will exceed book value per share since shareholders are obtaining a return in excess of their opportunity cost.

NCJC, *et al.*, Morin Direct Rebuttal Cross Ex. 1 (Official Ex. vol. 8, Part 2, at 72). Moreover, witness Morin has suggested that regulators should set "the allowed return so as to obtain an M/B ratio of at least 1.0…[which] abides by the financial integrity criterion of the *Hope* case and the financial soundness criterion of the *Bluefield* case." *Id.* at 89.

But witness Morin nevertheless discounts the significance of market-to-book ratios of regulated public utilities far surpassing 1.0. Witness Morin has not justified his claim that regulators should likewise disregard this key metric, which can reveal whether allowed ROEs have become out of sync with investors' actual expected returns. Witness Ellis demonstrated in detail that witness Morin's attempt to explain away the significance of excessive market-to-book ratios lacked substance. *Id*. at 708-19. For example, without any merit, witness Morin attempted to justify excessive market-to-book ratios as being necessary to address inflation. *Id*. at 710-11. Expected inflation is already reflected in the cost of debt and equity calculations.

To the extent witness Morin would justify market-to-book ratios of about 2.0 for the proxy group as somehow making up for periods when the ratios were below 1.0 does not comport with the historical record. Those ratios have averaged over 1.0 since the 1920s, so regulators could maintain a market-to-book ratio of 1.0 into perpetuity and the average long-run ratio would never drop below 1.0. *Id*. Nor is there any merit to witness Morin's suggestion that utilities could not attract capital without maintaining market-to-book ratios above 1.0. As witness Ellis demonstrated, investors buy shares of companies spanning a wide range of market-to-book ratios, including those below 1.0, as was the case for the utility sector from the early 1970s to mid-1980s, a time when utilities were nevertheless able to attract equity capital. *Id*. at 705, 713.

Notably, when public utilities were experiencing market-to-book ratios below 1.0 in the 1970s and early 1980s, Lawrence Kolbe of Brattle argued that achieving a market-to-book ratio of 1.0 should be a "guide for regulators," because in that instance, the allowed rate of return will be equal to the cost of capital. *Id.* at 717-18 (quoting A. Lawrence Kolbe, James A. Read, Jr., and George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, Charles River Associates, Inc. at 25 (1984)).

Alfred Kahn observed this same problem from a prior era when market prices of public utilities had appreciated to one-and-a-half and two times their book value (from the late 1940s to 1965), which he explained was caused by permitting utilities to earn returns that were considerably more that their actual cost of capital. *Id*. at 704 (quoting Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, Mass. Inst. Tech. at 48 (fn. 69), 50 (1970)). Sound economic principles would support the Commission in considering market-to-book ratios when establishing the lowest possible ROE that would comport with constitutional and legal standards.

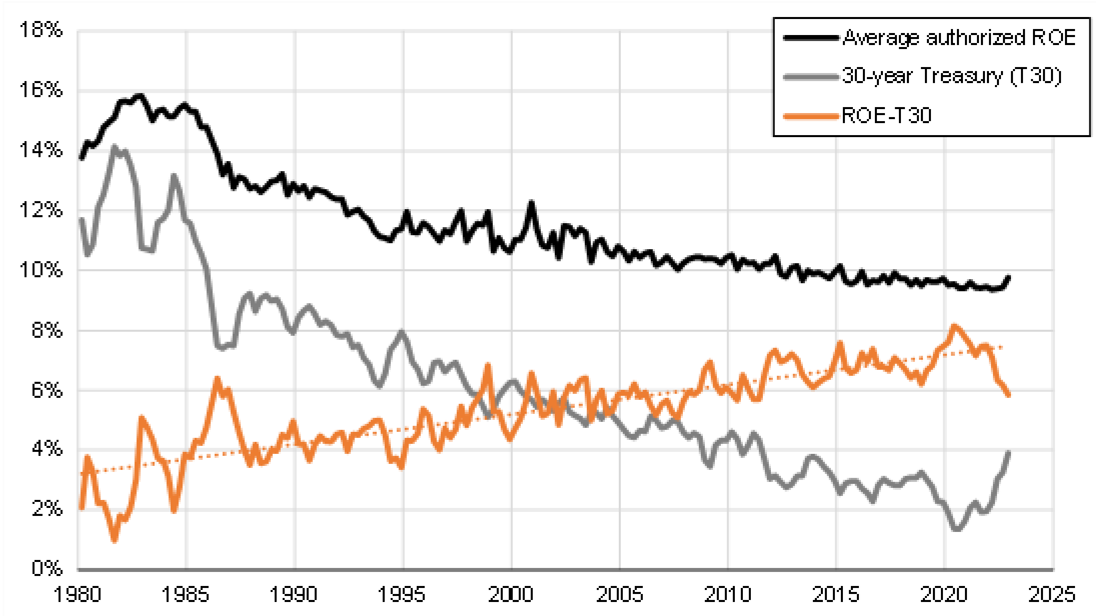
The inescapable logic of witness Morin's testimony is that a higher-than-average authorized ROE would provide Duke some kind of advantage as it competes for capital. Taken to its logical extreme, this would suggest that Duke would somehow be better able to attract equity capital investments with an authorized ROE that is well above the national average and that this would in some way redound to the benefit of Duke's ratepayers. But there is no basis for this position. If the Commission were to take this idea seriously and award DEC an allowed ROE of 12%—a figure well above any reasonable estimate of the cost of equity—in order to ensure that DEC could attract equity investors, what would be the actual result? An authorized ROE that is higher than the cost of capital (i.e., what investors would require) would result in a one-time boost in the stock price as investors account for the additional revenue from customer rates that can go to pay dividends (and thus, compensate equity investors). This jump in stock prices would produce a windfall for existing shareholders. But after the upward change in stock price, the actual returns on equity for anyone purchasing the stock at the higher price would level out to the returns available from utilities generally. This is one reason why it is important for the Commission to recognize how these concepts are distinct: the cost of equity capital (what reasonable investors expect to earn on their equity investment), the ROE (the actual returns earned on the book value of equity), and authorized ROE (the amount set by regulatory commissions).

DEC introduced no evidence suggesting that those utilities that have been awarded higher than average ROEs by public utilities commissions have been at any competitive advantage when it comes to attracting equity investment capital or that those higher ROEs have provided any material benefit to ratepayers. Such higher ROEs simply get baked into investor expectations in the form of higher stock prices, which result in increased market-to-book ratios, meaning that actual returns to investors who buy at the inflated stock price end up at about the industry average. Meanwhile, the captive ratepayers of those utilities that have been allowed excessive ROEs end up paying more in rates than is justified and receive no corresponding benefits.

2. Widening spread between the Risk-Free Rate and Authorized ROEs.

The widening spread between the risk-free rate (as represented by the 30-year U.S. Treasury rate) and commission-authorized ROEs is further evidence that allowed ROEs exceed the actual cost of equity. Both DEC witness Morin and NCJC, *et al.* witness Ellis provided a graphic representation of this widening spread (represented by the orange line in Ellis Figure 6, growing from about 2% in 1980 to 8% in 2020). Tr. vol. 15, 721, Figure 6; Morin Ex. 9 (Official Ex. vol. 8, Part 2 at 549).

Ellis Figure 6. Quarterly average authorized ROE and 30-year Treasury rate



Witness Ellis demonstrated that in addition to the national trend of authorized ROEs exceeding the cost of capital, DEC's authorized ROEs have exceeded the national average for authorized ROEs, despite DEC maintaining a vertically integrated business model that has a lower risk profile than many of its peers. Tr. vol. 15, 723-24.

Witness Morin does not attempt to explain the widening spread between the risk-free rate and authorized ROEs since 1980, but instead takes them as "presumably" reflective of "market-based methodologies" and the "actions of objective unbiased investors in a competitive marketplace." Tr. vol. 7, 245. But he does not explain in what possible way commission-authorized ROEs are the result of actions of investors in a competitive marketplace. Witness Ellis, in contrast, cited the scholarship of researchers at Carnegie Mellon, who investigated this widening spread between the risk-free rate and authorized ROEs and could not find a satisfactory economic explanation for the widening divergence. They concluded that the result is "excess returns [that] translate into tangible profits for utility firms." Tr. vol. 15, 721 (quoting Ex. MEE-3, David C. Rode & Paul S. Fishchbeck, Regulated equity returns: A puzzle, 133 Energy Pol'y 1, 16 (2019)) (Official Exhibits, vol. 15, Part 1 at 1155-71); *see also* Ex. MEE-2, Karl Werner and Steve Jarvis, Rate of Return Regulation Revisited*,* (2021) (concluded that "the ROE that [electric and gas] utilities are allowed to earn has changed dramatically relative to various financial benchmarks in the economy. Across relevant benchmarks, we found that current rates are perhaps 0.5–4 percentage points too high, resulting in $2–8 billion in excess rate collected per year, given the existing ratebase.") (Official Exhibits, vol. 15, Part 1 at 1148).

Any model for estimating the cost of equity that relies on previously authorized ROEs will have the effect of locking in this widening spread and should be disregarded. Tr. vol. 15, 197-98. Witness Ellis noted that relying on previously authorized ROEs to estimate the actual cost of equity is akin to basing a diet recommendation solely on what a person has been eating rather than on what foods they should eat to be healthy. *Id*. at 722-23.

3. Authorized ROEs for regulated public utilities are higher than independent capital market assumptions about returns on U.S. equity markets generally.

Authorized ROEs for the regulated public utilities in the proxy group are higher than expected returns provided by capital market assumption reports from independent investment firms for equity markets as a whole. Tr. vol. 14, 86, Table

CCW-10; tr. vol. 15, 700-02 (setting forth witness Ellis's review of Capital Market Assumption reports).

As witness Morin acknowledged, to the extent those independent capital market assumptions are reflective of actual investor expectations, they would contradict any authorized ROE higher than those expected returns from the market generally. Tr. vol. 7, 325. The reason for this is straightforward: utility stocks have a lower risk profile than the equity market, given their consistent cash flow, protection from competition, dividends with above-average yields, and steady earnings, even during recessions. *Id.* at 325-26; tr. vol. 15, 700. In other words, if it is true that investors are expecting returns that average about 6.75% from the equity markets, as summarized by Public Staff witness Christopher Walters, then the cost of capital from the point of view of investor expectations for a public utility like DEC must fall below those average ranges. Tr. vol. 7, 325-26, 184; tr. vol. 14, 84-85; tr. vol. 21, 622-24; tr. vol. 15, 701-02.

As witness Ellis demonstrated, none of the capital market assumption reports out of the dozens that he reviewed indicate that investors are expecting returns greater than 8.7% over the next ten years from the market as a whole. Tr. vol. 15, 702, Figure 3. As Morin acknowledged, investor ROE expectations for a public utility like DEC are necessarily below that range. On the stand, however, witness Morin incorrectly stated that witness Ellis's recommended ROE for DEC was higher than the expected market return from the independent capital market assumption reports that he analyzed. Tr. vol. 8, 42. The 6.15% ROE witness Ellis has recommended was, as would be expected, below the average near-term expected returns investors are expecting as reflected in capital market assumption reports.

In rebuttal testimony, witness Morin's principal reason for why the Commission should disregard capital market assumption reports is that such market forecasts include disclaimers. Tr. vol. 7, 325-26; tr. vol. 8, 39-40 (quoting from the fine print of the final page of the 2023 Long-Term Capital Market Assumptions report from JP Morgan Chase). But if witness Morin took this argument seriously, he could not in good faith rely on Value Line's growth forecasts. Tr. vol. 7, 222-30; tr. vol. 8, 39-42. Value Line has the same sort of disclaimers in its reports, as would any reasonable financial publication that presents a forecast of uncertain future market or economic conditions. *Id.* at 8, 40-41; NCJC, *et al*. Morin Direct Rebuttal Cross Ex. 5 (Official Ex. vol. 8, Part 2 at 120-22).

Witness Morin has no principled reason for why the Commission should disregard independent Capital Market Assumption reports, which support the conclusion that allowed ROEs set by public utility commissions are higher than justified in comparison to reasonable investors' expected returns. This lack of a principled reason to disregard the findings of Capital Market Assumption Reports from institutional investors and professional analysts is not surprising, given that witness Morin otherwise justifies relying on analysts' forecasts of long-term growth rates for his DCF model:

> Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by

> large reputable organizations, and the data are readily available and are representative of the consensus view of investors and are thus consistent with the use of current market prices. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity.

Tr. vol. 7, 216. These same reasons support the Commission's consideration of Capital Market Assumption reports when estimating the returns investors expect under current market conditions for the markets as a whole, which will be higher than investors' expected returns for utility investments.

Morningstar, an investment advisor firm, determined as part of its discounted cash flow analysis that the cost of equity for Duke Energy Corporation, the parent company of DEC, is 7.5%. Public Staff Morin Direct Rebuttal Cross Ex. 20, at 4 (Official Ex. vol. 8, Part 1 at 721). Morningstar notes that a 7.5% cost of equity for Duke Energy "is lower than the 9% rate of return we expect investors will demand for a diversified equity portfolio, reflecting Duke's lower sensitivity to the economic cycle and lower degree of operating leverage." *Id.* This kind of outside view of investor expectations provides a more realistic assessment of the actual cost of equity than the results of any of witness Morin's analyses and should carry significant weight with the Commission. Morningstar, like the Capital Market Assumption reports noted above, is unbiased when it comes to the contested issue of authorized ROE in this case; Morningstar is just trying to find an accurate estimate of the cost of equity so that it can provide informed investment advice to its clients.

To the extent the authorized ROE is higher than required to fairly compensate investors "commensurate with returns on investments in other enterprises having corresponding risks," customers will pay more to DEC on their utility bills than is justified. *Hope*, 320 U.S. at 603. The Commission has significant discretion when setting the authorized ROE. There is ample evidence in the record to support an ROE that is significantly below the inflated and self-interested 10.4% that DEC is seeking in this case. Doing so will save DEC's customers hundreds of millions of dollars without jeopardizing DEC's credit quality or ability to attract capital investments on reasonable terms.

C. DEC Did Not Meet Its Burden of Proof to Establish an Authorized ROE of 10.4%.

Any estimate of the cost of equity that is used to set the authorized ROE will be informed by judgment calls about the appropriate inputs and assumptions used to make that calculation. At every step, witness Morin's assumptions and choices for model inputs had the effect of biasing his results upwards.

1. Witness Morin has a history of recommending ROEs for electric public utilities before state commissions that are, on average, 100 basis points higher than those approved by those commissions.

A straightforward reason for this Commission to reject witness Morin's proposed ROE of 10.4% is that there is no evidence that any public utility commission has ever adopted his recommended ROE. A review of state public utility commission rate case decisions for electric public utilities in which witness Morin made the ROE recommendation for the utility since the early 1980s reveals that his recommendations are always higher than the ultimate decision reached by the commission, regardless of whether the cases were fully litigated or settled. NCJC, *et al*. Morin Direct Rebuttal Cross Ex. 2 (Official Ex. vol. 8, Part 2 at 77); tr. vol. 8, 32-35. The one apparent exception—in which the recommended ROE is listed as being the same as the authorized ROE—is from a Hawaii Electric case (Docket 04-0113). Tr. vol. 8, 35.[10] But the order in that case reveals that in this instance, Regulatory Research Associates put the wrong number in the recommended ROE column. Witness Morin initially recommended a ROE of 11.5%, which was reduced to 11% in his rebuttal testimony, before the Hawaii commission ultimately approved the 10.7% ROE agreed to in settlement. *Id*. DEC offered no evidence to rebut this showing that witness Morin's inflated recommended ROEs have never been accepted by state public utility commissions.

In every case before a state public utility commission in which Morin provided the electric utility's proposed ROE, commissions have approved ROEs that are, on average, 100 basis points lower than his recommendation. Witness Morin agreed that in those cases, his testimony would have included the assertion that his recommended ROE was the minimum amount required to comply with constitutional standards. Tr. vol. 8, 31. And witness Morin had no evidence that the resulting commission-authorized ROEs impaired the ability of those utilities to access the capital markets or adversely affected the financial integrity of those utilities in any way. *Id*. But it is an inescapable fact of basic arithmetic that those

[10] The Commission took judicial notice of the decision of the Public Utilities Commission of Hawaii in *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of Rate Increases and Revised Rate Schedules and Rules*, Docket No. 04-0113, Decision and Order No. 24171 at 73-78 (May 1, 2008). Tr. vol. 8, 35.

commission-approved ROEs saved ratepayers substantial sums of money in comparison with witness Morin's recommendations.

As set forth above in Section IV.B., there is considerable evidence that even those commission decisions, which are on average 100 basis points lower than witness Morin's recommended ROEs, are higher than the actual costs of capital for regulated public utilities since the 1990s. For this reason, simply skimming 100 basis points off the top of witness Morin's recommended 10.4% ROE would not be sufficient to comport with the legal requirement to set the lowest ROE possible consistent with constitutional mandates. But even that result would be a substantial improvement for North Carolina ratepayers over accepting DEC's recommended ROE at face value.

The independent cost of equity estimates provided by expert witnesses for the Public Staff and CUCA were similarly 105 to 115 basis points lower than witness Morin's recommendation, in the event the Commission approved a MYRP. Tr. vol. 7, 296. Witness Ellis optimized his recommended ROE, which is 425 basis points lower than witness Morin's recommendation, with a 58.8% equity ratio that would allow DEC to maintain the FFO-to-debt ratios needed to maintain its current bond rating. Tr. vol. 15, 830-31. Witness Ellis's recommendation would save customers $520 million each year (based on DEC's initial requested revenue requirement). *Id*. at 832.

2. Key inputs and assumptions underlying witness Morin's analysis biased the results of his DCF and CAPM models upwards, the results of his Morin ECAPM and Risk Premium Methods should be disregarded, his position on the effect of risk mitigators was inconsistent, and his flotation adjustment is unwarranted.

Any model is only as good as the inputs and assumptions that are used to implement that model. Tr. vol. 7, 209-10. DEC witness Morin made several choices that upwardly biased the results of his DCF and CAPM models (the only two of Morin's models that the Commission should consider when estimating the cost of equity). Correcting those errors results in a much lower cost of equity estimate that the Commission should use when setting the authorized ROE for DEC.

a. <u>Morin's Constant Growth DCF result is unreliable.</u>

The discounted cash flow (DCF) model is based on a widely used mathematical formula for the value of a stream of cash flows that grows in perpetuity. Tr. vol. 15, 726. The model can be expressed to estimate the cost of equity by adding expected dividend yields plus the expected rate of growth of dividends, earnings, stock price, and book value. Tr. vol. 7, 212-13. The model thus relies on two key variables: dividend yields and growth rates. Errors in either input will distort the results of the model.

i. Morin's Constant Growth DCF result is unreliable because it irrationally assumes analyst's short-term growth projections continue indefinitely, which is economically impossible, and includes other sources of upward bias.

Witness Morin's constant growth discounted cash flow analysis (CG DCF) suffers from a fatal flaw: it assumes that "dividends can grow at analysts' estimated EPS growth rates into perpetuity. This assumption is economically impossible and adds substantial upward bias to his results." Tr. vol. 15, 726. Public Staff witness Walters came to a similar conclusion: his "major concern with Dr. Morin's DCF analysis is that his DCF results are heavily impacted by growth rates that cannot be sustained in the long run… ." Tr. vol. 14, 104.

One alternative approach that removes the flawed assumption that short-term analyst growth forecasts can be sustained into perpetuity in the CG DCF model is a multi-stage DCF, which can consider varying growth rates at different timeframes, including a terminal growth rate that matches the overall economy. Witness Ellis and Public Staff witness Walters employed multi-stage DCF models in their analyses. Tr. vol. 14, 64-70; tr. vol. 15, 744-50. Witness Walters's multi-stage DCF model estimated the cost of equity for the proxy group of about 8.41% (median). Tr. vol. 16, 264. The multi-stage DCF can consider both the short-term growth forecasts as well as terminal growth rates that converge on growth rates in the economy as a whole.

In rebuttal, witness Morin testified that the "Achilles' heel" of the multi-stage DCF is the assumption that "utility growth rates match that of the macroeconomy" and that he is "not aware of any financial literature supporting the notion that the investment community looks to GDP growth over the next several decades when evaluating utility investments." Tr. vol. 7, 314.

But Morin's testimony is contradicted by his own publication, *New Regulatory Finance*. In a section relating to growth in the non-constant DCF model (which includes the multistage DCF model), witness Morin wrote precisely the opposite of what he said in rebuttal: "It is useful to remember that eventually all company growth rates, especially utility service growth rates, converge to a level consistent with the growth rate of the aggregate economy." NCJC, *et al*. Morin Direct Rebuttal Cross Ex. 1 (*New Regulatory Finance* at 308) (Official Ex. vol. 8, Part 2 at 70). Despite witness Morin's assertion that the multi-stage DCF is "mis[-]specified," he recognized the shortcomings of the constant growth DCF in his book:

> The problem is that from the standpoint of the DCF model that extends into perpetuity, analysts' horizons are too short, typically five years. It is often unrealistic for such growth to continue into perpetuity. A transition must occur between the first stage of growth forecast by analysts for the first five years and the company's long-term sustainable growth rate.

Id. Although Morin claimed to be unaware of *any* financial literature that would support the idea that over the long term, growth rates of utilities would converge to GDP, he himself wrote about that phenomenon, further noting that "it is quite possible that a company's dividends can grow faster than the general economy for five years but it is quite implausible for such growth to continue into perpetuity." *Id.* at 87.

ii. Exclusive reliance on forecast Earnings Per Share for growth rate.

An additional factor that upwardly biased witness Morin's CG DCF result is his reliance on an analyst's estimate of future earnings per share growth rates. Tr. vol. 15, 729-30; tr. vol. 14, 104 (noting that Value Line's growth rates represent the projections of a single analyst). Witness Morin otherwise notes his belief in seeking out consensus forecasts, but for this key variable in his CG DCF calculation, he relies instead on *a single analyst's forecast*. Tr. vol. 7, 216; vol. 8, 41 (witness Morin reiterating the importance of relying on a consensus forecast). Just as flawed, though, is his sole reliance on analysts' forecasts of earnings-per-share growth as the *only* source of the growth factor in the DCF calculation. As a general matter, analyst estimates are known to be upwardly biased. Tr. vol. 15, 729-31 (citing Marc Goedhart, Rishi Raj, and Abjishek Saxena, *Equity analysts: Still too bullish*, McKinsey Quarterly (Apr. 2010); Stefano Cassella, Benjamin Golez, Huseyin Gulen, and Peter Kelly, *Horizon Bias and the Term Structure of Equity Returns* (Nov. 2021)). A comparison of past forecast dividend-per-share growth rates of the proxy group to their historical growth rates demonstrates the problem of overly optimistic analysts' forecasts. *Id.* at 743, Figure 12. On average, the forecast rates for the proxy group are approximately 3.5% higher, in both real and nominal terms, than the historical average. *Id*. at 742-43.

Witness Morin relies solely on analyst's forecasts of earnings per share (EPS) as a stand-in for dividend growth rates in the CG DCF model. Historical and forecast data, however, demonstrate that earnings-per-share growth is not representative of dividends-per-share growth over even the short (3-5 year) time horizon of analysts' EPS forecasts. Tr. vol. 15, 733. Witness Ellis provided compelling empirical evidence that EPS growth rates are not a suitable proxy for DPS growth rates. Both historical EPS and forecast EPS tend to be higher than DPS growth rates, another source of upward bias in Morin's DCF model. Because earnings tend to be more volatile than dividends per share, with higher earnings often following a year of poor performance, for example, relatively short-term EPS forecasts are not a viable input for growth rates in a CG DCF model. *Id.* at 979-85. Using Value Line's other forecasts for share price and dividends per share to calculate expected returns for the proxy group similarly demonstrate that EPS is not a suitable proxy for future dividend growth; using those Value Line forecasts results in an estimated cost of equity of 8%. *Id*. at 739-41. This proves that even Value Line's analysts do not assume that those EPS growth rates will apply to dividends or that those growth rates can be sustained into perpetuity. *Id.* at 741.

iii. Morin's CAPM results are biased upwards.

In the Capital Asset Pricing Model (CAPM), the cost of equity is derived by adding the risk-free rate to the market risk premium, which is in turn derived by multiplying the stock's beta by the difference between the expected return on the market minus the risk-free rate. Tr. vol. 15, 751-52; vol. 8, 224-25. Any upward bias on any of these variables will have a large impact in the estimated cost of equity calculation.

iv. ***Witness Morin does not support his decision to rely solely on Value Line for his beta estimates, which biases his results upwards.***

Beta—a key input into the capital asset pricing model—is the measure of how closely a given stock moves in relation to the market as a whole. In the CAPM, the estimated risk-free rate is multiplied by the beta, so any upward bias in the beta will have a large impact in the estimated cost of equity calculation. For the proxy group, witness Morin relied on only one source for betas, Value Line. Value Line uses the so-called Blume adjustment, which is based on research from the 1970s, which observed a general tendency of betas, on average, to regress towards 1.0. Tr. vol. 15, 774. But this general trend for stocks does not apply to utility stocks, which have tended to regress to betas of 0.50 to 0.60 since the 1950s. *Id.* at 774-75. Applying this adjustment to utility stocks has the effect of artificially increasing their betas one-third of the way towards 1.0 and has a large influence on biasing Morin's results upwards.

Witness Morin's principal support for his sole reliance on Value Line betas for his CAPM (as well as for the Morin ECAPM) analysis is an article from 1983, based on a review of betas largely from the 1970s. Tr. vol. 7, 362-63 (citing Harrington, *"Whose Beta is Best?"*, Financial Analysts' Journal, July-August 1983, Vol. 39); NCJC, *et al*. Morin Direct Rebuttal Cross Ex. 6 (Official Ex. Vol. 8, Part 2 at 123-29). Yet in that article, Harrington concluded that "there is no single best method of estimating a beta." *Id.* at 149. More importantly, for the utility sector, Harrington concluded that "beta forecasts…overestimated the actual betas." *Id.* at 151. The results from the utility sample indicated that Value Line betas had an error of 0.28, a sizeable error when the mean beta forecast for the sector was 0.7241. In other words, compensating for this error would bring Value Line's betas for the time in Harrington's study to 0.44.

In addition, Harrington concluded that Value Line's errors, which consistently overestimated actual betas, means that OLS betas (or raw betas) are superior for the utility sample. *Id.* When confronted with Harrington's conclusion that Value Line betas result in sizeable errors and those errors are always in the direction of inflating betas, witness Morin ignored Harrington's conclusion and instead relied solely on one metric, the mean square error of Value Line betas. *Id*. at 152; tr. vol. 8, 43-46. Witness Morin acknowledged that the direction of error is a relevant consideration, and it is significant if one particular method for estimating betas, such as Value Line's, consistently results in an overestimate. Tr. vol. 8, 46.

More recent academic analysis has found no basis for the use of the Blume adjustment for utility stocks over a several decade period. Richard A. Michelfelder & Panayiotis Theodossiou, *Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings*, 26:9 The Electricity J. at 60-68 (2013) (Ex. MEE 6). Witness Morin's reliance on Blume-adjusted betas from Value Line is unsupported by any recent academic study. The Commission's job is to use the best evidence at its disposal to accurately estimate the cost of equity capital when setting the authorized ROE. It is not enough to note that other witnesses rely on Value Line when there is compelling, unrefuted evidence in the record that Value Line betas are inflated and upwardly biasing the results of the CAPM models that rely on that input. Nor is it sufficient for witness Morin to declare that "investors" look to Value Line for betas when other providers of financial information to investors have dramatically larger numbers of users than Value Line. Tr. vol. 15, 776-78.

There are a number of equally valid and commonly used methods for estimating betas. The resulting betas can vary significantly depending on seemingly random differences in methodology, including the day of the week chosen to calculate weekly returns. *Id*. at 772. It is precisely for this reason that it is better to rely on a range of estimated betas that use different methodologies as opposed to relying on a single source, as witness Morin does. This is particularly problematic when that one source, Value Line, uses a Blume adjustment that artificially moves all betas one-third of the way towards 1.0 and produces results for utility stocks that are the highest of all the most commonly used methods. The supposed upward trend in utility betas that witness Morin cites only appears in sources that use a methodology like Value Line's. Other commonly used sources, such as Yahoo! Finance, S&P Global Market Intelligence, and Zacks do not show any such upward trend. Tr. vol. 21, 762-65. The Commission should not rely on any estimated cost of equity calculation that relies solely on Value Line betas.

v. Morin's unexplained decision to rely solely on forecasts from Blue Chip Economic Indicators for the risk-free rate biased his CAPM results upwards.

Establishing an accurate risk-free rate is a key variable in the CAPM. The risk-free rate is added to the product of the company's estimated beta times the market risk premium to derive the estimated cost of equity. Reliance on any assumption that artificially increases the risk-free rate will have a direct effect on the result of the analysis, unjustifiably inflating the estimated cost of equity. As explained in more detail below, witness Morin's decision to rely exclusively on the Blue Chip Economic Indicators forecasted 30-year Treasury rate was unreasonable and his resulting CAPM results should be disregarded.

Witness Morin testified that the risk-free rate was 4.3%. Tr. vol. 7, 225-30. Witness Morin does not, however, address the shortcomings with relying on the BCEI forecast, which has a long track record of being upwardly biased. There are several problems with witness Morin's approach. First, it is not logically consistent to use forecast rates for the CAPM model. *See* tr. vol. 15, 752. Second, BCEI has consistently overestimated U.S. Treasury yields for decades, making them an unreliable source for such a key input for cost-of-equity calculations. *Id*. at 753-54. Current market rates are better predictors of future rates than any economic analysts' forecasts, as witness Morin himself acknowledged in his recent book: "the bond market is very efficient in that it is difficult to consistently forecast interest rates with greater accuracy than a no-change [from the current interest rate] model." *Id*. at 752 (quoting *New Regulatory Finance*, at 172).

Witness Morin does not explain how investors can be relying on the BCEI forecasts on the one hand, which have a long track record of overestimating future interest rates, while market participants are at the same time buying bonds at current yields. Any purchase at today's yields indicates that investors do not expect the yield to go up (given the inverse relationship between a bond's value and its yield, buying today—if one expects the yield to increase—would mean the buyer expects a loss on their investment). Tr. vol. 15, 759.

Witness Ellis documented the close relationship between current market rates and future interest rates, showing that they are indeed a more reliable predictor of future rates. Tr. vol. 15, 758-60. Just as importantly, using current rates as a proxy for future rates has the virtue of being unbiased. They are equally likely to be too low as too high, unlike BCEI, which has a long history of overestimating future rates. *Id.*

vi. Reliance on arithmetic means.

Another assumption made by witness Morin that upwardly biases the results of his CAPM models is the use of arithmetic average returns to derive his historical market risk premium. In rebuttal, witness Morin went so far as to say that there "is no theoretical or empirical justification for the use of geometric mean rates of return in estimating the cost of capital." Tr. vol. 7, 357. But witness Ellis provided both empirical and theoretical support for using geometric averages in his direct testimony, including extensive quotes from leading scholars of valuation that support using geometric average returns when considering long-term cost of capital calculations. Tr. vol. 15, 782-84 (citing Tim Koller, et al., *Valuation*, McKinsey & Co. at 852-853 (6th ed. 2015) and Professor Aswath Damodaran). And witness Morin agrees that the goal of the CAPM is to consider the long-term cost of equity. Tr. vol. 7, 226 (testifying that the "expected common stock return is based on very long-term cash flows").

Geometric average returns are especially important for stock returns, which are negatively correlated over time. Tr. vol. 15, 784-86. In other words, good years in the markets are typically followed by bad years, and vice versa. *Id*.

For any analysis that covers a long-time horizon, such as the historical risk premium, the geometric average return will provide a more accurate result. Witness Morin apparently agrees, noting in his direct testimony that "geometric average return should be used for measuring historical returns that are compounded over multiple time periods." Tr. vol. 7, 236. His historical risk premium purports to do just that—consider historical returns over multiple time periods.

b. ***Morin ECAPM should be completely disregarded.***

The so-called Morin ECAPM is not used outside of utility regulatory proceedings. Tr. vol. 15, 798. The research justifying its use generally is out of date, does not fit more recent trends, and does not fit public utilities' stocks at all. *Id.* at 797-803. "Despite its name, the empirical data do not support the ECAPM's modifications to the traditional CAPM for use in estimating the cost of equity" for utilities. *Id.* at 1044. When the analysis cited as a reason for using the ECAPM is revised to reflect the parameters of a utility cost of equity proceeding, the purported flatness relative to a short-term rate disappears. *Id.* In his rebuttal testimony, Morin did not address any of witness Ellis's substantive critiques that demonstrate the unsuitability of the Morin ECAPM.

Importantly, witness Morin undercut the principal justification for using the Morin ECAPM—that it is required to adjust returns from "low-beta" securities. Tr. vol. 7, 240-43. Witness Morin otherwise testified that the utilities in his proxy group have a beta of 0.9, which is far outside the range of a "low-beta" stock. On the stand, witness Morin testified that low-beta securities are those that have a beta of 0.3 to 0.4 or lower, far below the 0.9 for utilities stocks in the proxy group. Tr. vol. 8, 82. In other words, witness Morin's claim that utility betas are approaching 1.0 undercuts his principal justification for using ECAPM in the first place, which is only specified for low beta securities. Tr. vol. 8, 217. Morin ECAPM results should be disregarded completely.

c. ***<u>Morin's Risk Premium results should be disregarded.</u>***

As with the Morin ECAPM, the Historical and Allowed Risk Premium Models (RPM) are not commonly used in finance and suffer from invalidating flaws. Tr. vol. 15, 805-09. Both of these models "confuse the cost of equity and the return on equity." *Id*. at 805. The RPM models are based on either historical or allowed returns, neither of which convey any information about investors' expected returns on equity. The Historical RPM is based on historical stock returns, and thus, would repeat the equity premium puzzle (a period in which stock returns exceeded reasonable investor expectations). *Id*. The Allowed RPM is based on past regulatory ROE decisions, which, as explained above, are in a decades long period of overearnings from authorized ROEs that have exceeded the cost of capital. *Id*. at 806.

The DC Circuit Court of Appeals recently reversed a FERC decision that disregarded, without explanation, FERC's previous rejection of RPM, finding that the RPM "defies general financial logic," is not relied upon by investors, is less accurate than Discounted Cash Flow models, is largely redundant with Capital Asset Pricing Models, and presents "particularly direct and acute" circularity problems because it uses past-allowed returns to set new ones. *Id*. at 808-09;

NCJC, *et al*. Morin Direct Rebuttal Cross Ex. 3at 27 (Official Ex. vol. 8, Part 2 at 109) (internal quotation marks omitted). The results of witness Morin's RPM analysis should be disregarded for these same reasons.

d. ***Flotation adjustment is unwarranted and not allowed under these circumstances.***

The flotation cost adjustment proposed by witness Morin is unwarranted and not allowed under North Carolina law. The Commission cannot include a flotation adjustment in a general rate case based on an historic test year when the Company did not issue any stock and has no plans to issue stock during the MYRP (and thus, has incurred and has no plans to incur actual flotation costs). *State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utils. Comm'n*, 322 N.C. 689, 700, 370 S.E.2d 567, 574 (1988) ("Since no evidence was introduced that Duke intends to issue new stock for the next three or four years, and because there was no evidence regarding the probable cost of a prospective issuance, we question whether the record supports any financing cost adjustment"). The Commission should reaffirm its correct decision on this discrete issue from its August DEP rate case Order.[11]

In addition, as witness Ellis demonstrated, Morin's flotation cost adjustment is based on flawed assumptions and ignores the reality that utilities' stocks generally, and DEC's parent company in particular, are trading well in excess of market-to-book ratios of 1.0. Actual flotation costs would be much smaller for the proxy group than Morin's model suggests and are overwhelmed by the

[11] *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice*, In the Matter of Application of DEP for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and PBR, Docket No. E-2, Sub 1300, at 164-65 (Aug. 18, 2023).

imprecision of any model that would be used to estimate the cost of equity. Tr. vol. 15, 809-14.

D. Witness Ellis, Relying on Sound Finance Principles, Calculated a More Accurate Estimate of the Cost of Equity for Public Utilities and Established an Appropriate ROE for Commission Consideration.

As set forth above, NCJC, *et al*. witness Mark Ellis's testimony demonstrated that authorized ROEs for public utilities exceed the actual cost of capital and identified the faulty inputs and assumptions that upwardly biased witness Morin's estimates for DEC's ROE. In addition, using inputs and assumptions that better reflect reality, witness Ellis provided an independent estimate of DEC's actual cost of equity using a multi-stage discounted cash flow (MS DCF) analysis and CAPM. As explained above, models that are based only on historic or authorized ROEs (such as witness Morin's Risk Premium methodology) provide no information about the cost of equity and thus, were not conducted by witness Ellis. In addition, witness Ellis considered the relationship between ROE and capital structure to arrive at a recommendation that would preserve the funds-for-operations (FFO) to debt ratio that DEC requires to maintain its current credit rating. DEC did not rebut witness Ellis's conclusion that a lower ROE with a modified capital structure would allow the Company to maintain its current FFO-to-debt ratio and thus, its A2 credit rating.

It would be unreasonable to disregard witness Ellis's thoroughly explained analysis that is grounded in solid application of finance principles simply because the result of his analysis is lower than witnesses who used assumptions that are closer to witness Morin's. When estimating the cost of equity capital, any given number of witnesses will get similar results if they use substantially similar assumptions. Any witness who relies on different assumptions will necessarily come up with a different range for the estimated cost of equity. But that does not mean that the one witness is wrong and the group of witnesses is right. When Galileo posited his theory of the heliocentric solar system, based on his accurate astronomical observations, his was a lone voice amongst many who believed the Earth was the center of the universe. But that did not make him any less right. To the extent that the Commission disagrees with any particular aspect of witness Ellis's analysis or his critique of witness Morin, it should make findings of fact that explain the reason for the Commission's conclusions in sufficient detail for the public to understand its decision.

Witness Ellis demonstrated that a cost-based ROE of 6.15% with a modified capital structure would save DEC's customers $520 million per year (from DEC's original proposed revenue requirement) while allowing DEC to maintain its current A2 credit rating.

1. Ellis's use of MS DCF and CAPM, standard tools employed in finance to estimate the cost of equity, corrected the flaws in Witness Morin's approach.

a. Results of Ellis's Multi-Stage Discount Cash Flow (MS DCF) Model.

To overcome the shortcomings inherent in the constant growth discounted cash flow model, witness Ellis used a multi-stage DCF method, which models different dividend growth rates over different time periods. Tr. vol. 15, 744. Ellis used an initial growth stage of three years, which is the low end of analysts' EPS growth rate forecast horizon, mitigating the known upward bias of analysts' forecasts. *Id.* at 745. In addition, Ellis considered the average of analysts' short-term growth rate forecasts from three different companies (S&P Global Market Intelligence, Yahoo! Finance, and Zacks), drawing on a much larger sample of analysts' forecasts than Morin's single-analyst projection from Value Line. For the terminal stage, witness Ellis used long-term inflation projections for the growth rate in the proxy group, given the observed long-term correlation between utilities' growth rates (as measured by share price, dividend, and book value) and inflation. *Id.* at 747-49. In between the initial and terminal stages, witness Ellis modeled a 10-year transition stage, in which the growth rate is the average of the initial and terminal rates. *Id.* at 744-45.

Using the multi-stage DCF model, the average resulting cost of capital estimation for the proxy group is 6.63%. *Id*. at 750. Ellis also used the multi-stage DCF to estimate the market risk premium in his CAPM analysis, as explained in more detail below.

b. ***<u>Results of Ellis's Capital Asset Pricing Model (CAPM).</u>***

To correct for witness Morin's flawed inputs to the CAPM, witness Ellis used the following inputs for the capital asset pricing model: (1) an average beta of the proxy group of .55, derived from betas provided by Yahoo! Finance and Zacks, calculated using five years of monthly returns, striking an appropriate balance between current market sentiment and historic average for utilities, which is consistent with the objective of estimating a multiyear cost of equity; (2) an estimated market risk premium, calculated as an average (about 4%) of both the long-term, geometric average historical MRP (4.91%) and a forward looking estimate using the multistage DCF (3.96%); and (3) risk-free rate based on the current 30-year U.S. Treasury rate rather than the forecast rate, which was 3.87% at the time Ellis prepared his testimony. Tr. vol. 15, 788-96. The resulting estimated cost of equity capital for the proxy group is 6.06%. *Id*. at 796.

c. <u>The relationship between authorized ROE and capital structure.</u>

Allowed return on equity and capital structure should not be considered in isolation from one another. All other factors being equal, a lower equity ratio in a utility's capital structure tends to increase the cost of equity. Tr. vol. 15, 815. This makes sense given that debt investors have the first priority on returns from the utility's business. *Id*. As the equity ratio declines, a smaller share of that cash will be available to pay shareholders (i.e., equity owners). *Id.* Given the potential heightened risk of uncertainty, it will result in a higher cost of equity. *Id.* At the same time, given that the cost of equity is higher than the cost of debt, a higher equity ratio will increase customer costs without any adjustment to the authorized ROE. *Id*. at 816. The capital structure also has a large role in a company's credit rating, such that a higher equity ratio tends to improve a utility's credit quality. *Id.* at 816-17. Similarly, because the authorized ROE has a direct effect on customer rates, and thus, the cash flow to the utility, the ROE has an effect on the funds for operations, a key metric used to determine a company's credit quality. *Id.* at 818.

As a result of the interplay between capital structure and cost of equity, and because the proxy group average market equity ratio is different than the capital structure proposed by DEC, the proxy group average cost of equity estimate cannot be used to directly estimate DEC's cost of equity. Witness Morin's analysis did not consider the interplay between capital structure and cost of equity at all in his analysis. *Id.* To account for differences in capital structure amongst the proxy group, witness Ellis unlevered the ROEs (in other words, removed any distorting effects of various equity ratios in the cost of equity estimates for the utilities in the proxy group). *Id.* at 822. The average equity ratio for the proxy group is approximately 55%. *Id*. at 815. Unlevering the estimated cost of equity calculations for the proxy group lowered the estimated cost of equity to an average of 5.21%. *Id.* at 824.

As witness Ellis demonstrated, considering both the capital structure and ROE in tandem can allow the Commission to optimize an allowed ROE that can maintain the utility's funds-for-operations-to-debt (FFO-to-debt) ratio at a sufficient level to maintain its current credit rating, providing for a lower estimated cost of equity, and providing significant rate relief to DEC's customers. Using information provided by DEC, Ellis optimized the capital structure and the proposed ROE to levels that allow DEC to maintain its current A2 debt rating (with an FFO-to-debt of 23%). *Id.* at 826. This optimized ROE and capital structure would reduce customers' costs by $520 million each year (below DEC's original proposed revenue requirement). *Id.* at 828.

DEC's cost of debt witness Newlin did not make any reference to the FFO-to-debt ratio or any other credit metrics in his direct testimony. *Id.* at 817-18. Nor did witness Newlin indicate that he had any disagreement with the underlying FFO-to-debt metrics that Ellis included in his direct testimony. And notably, neither witness Newlin nor Morin provided any forecast FFO-to-debt analysis under

DEC's proposed ROE of 10.4% with a 53% to 47% equity to debt ratio. Instead, witness Newlin simply referred to his proposed 53% equity ratio as "optimal" without any support. *Id.*

2. Witness Morin did not rebut the essential findings of witness Ellis.

Witness Morin's rebuttal does not address the most important points raised in witness Ellis's testimony. At no point does witness Morin grapple with the empirical evidence that demonstrates that authorized ROEs for utilities are out of sync with reasonable assessments of investors' expectations. At no point does Morin find fault with the results of witness Ellis's MS DCF and CAPM analyses, other than quibbling with his source of betas and two choices for estimating the market risk premium used in the CAPM: (1) the use of geometric returns and (2) considering the total return on U.S. Treasury bonds as opposed to the income-only component of those bonds. Instead, Morin resorts to *ad hominin* attacks on Ellis's approach, calling it "non-mainstream, far-fetched, and unorthodox." But Ellis's approach more closely follows mainstream finance approaches for estimating the cost of equity than does witness Morin's approach. For example, witness Morin offered no examples of the Morin ECAPM or Authorized Risk Premium methods being used outside of utility regulatory proceedings.

In a similar vein, witness Morin mischaracterizes witness Ellis's rightful concern about authorized ROEs exceeding the actual cost of capital—which, as Morin acknowledges, would represent a wealth transfer from ratepayers to shareholders—as "virulent," "unprofessional," and a "mockery." Tr. vol. 7, 356. But this attack on Ellis's testimony is completely unwarranted. In the cited passage, Witness Ellis is critiquing a process that utilities around the country have successfully turned to their advantage, resulting in excess profits to utility shareholders. Much of that critique is aimed at the flawed information presented to regulators from people like DEC witness Morin. Tellingly, witness Morin can point to no specific part of Ellis's testimony as a "mockery" of regulators. Instead, the single example that Morin relied on was a reference to a mathematical model, one which simply highlights the inherent bias in any model that allows for consideration of past results when making new decisions. Tr. vol. 15, 719 (referencing the Pólya urn model). And even in that example, witness Ellis noted that the model is an oversimplification, because regulators take into account more information than just past authorized ROEs. *Id.*

a. Morin improperly cut and paste a portion of his rebuttal of Ellis from the DEP case that is not germane to the DEC rate case.

Witness Morin repeated a criticism lodged at witness Ellis's direct testimony from the DEP rate case that was not present in the DEC rate case. Tr. vol. 7, 356 (relating to an issue with dividend yield calculations that arose in the DEP rate case but that were not an issue in the DEC case). The page references cited in witness Morin's rebuttal are to witness Ellis's uncorrected pre-filed testimony in the DEP rate case. This sloppy repetition is particularly notable because it relates to a point of confusion created by an unexplained change in methodology that Morin decided to employ between his direct and supplemental testimony in the DEP case. Witness Ellis later corrected that point and removed the reference to witness Morin's adjustments to dividend yields in the DEP case itself and did not repeat that criticism in the DEC case at all. This sloppy cut-and-paste repetition calls into question the relevance of the other portions of witness Morin's rebuttal.

b. ***<u>Morin inaccurately refers to steps Ellis took as "inconsistencies."</u>***

In rebuttal, witness Morin purported to identify three inconsistencies in witness Ellis's testimony. In each case, witness Morin was wrong.

First, witness Morin claimed that "Mr. Ellis denounce[d] the use of analysts' growth forecasts in a DCF analysis" but later used analysts growth forecasts in his own analysis. Tr. vol. 7, 353. In other words, witness Morin suggested that witness Ellis denounced a particular approach in his testimony but later employed that same approach. That is false. Witness Ellis denounced the use of *certain* growth forecasts in *certain* DCF analyses, not in all situations. Specifically, he critiqued the use of analysts' *short-term* growth forecasts in the *constant-growth* DCF model, which witness Morin relied on into perpetuity, as opposed to the *multi-stage* DCF model, which witness Ellis used. Tr. vol. 15, 731-35.

As set forth in Section IV.C.2.a.i. above, it is improper to assume analysts' near-term growth rate forecasts will continue into perpetuity, as was the case in Morin's constant growth DCF model. *Id*. Nevertheless, witness Ellis recognized that, despite their shortcomings, analysts' near-term forecasts are "viewed as the best available estimates of near-term investor expectations." Tr. vol. 15, 746-47. But because of the well-known biases in those forecasts, "relatively little weight should be placed" on those forecasts when estimating the cost of equity. *Id.* As explained above, a virtue of the multi-stage DCF is that it can appropriately weigh those near-term expectations as just one component of the model, and not project those growth rates continuing forever, as witness Morin unreasonably assumes.

In short, witness Ellis did not denounce the use of analysts' growth rate forecasts in all situations, as witness Morin carelessly suggested. He instead denounced witness Morin's use of 3-to-5-year growth rate forecasts into perpetuity in the constant-growth DCF model. And witness Ellis did not contradict himself by considering those near-term forecasts. He instead explained how they can be used in a way that mitigates their shortcomings.

Second, witness Morin erroneously implied that witness Ellis's use of two different long-term growth rates in two distinct sections of his testimony was inconsistent. Witness Morin wrote, "In his non-constant DCF analysis, [witness Ellis] relies on a long-term growth rate of 1.77% [*sic*] but he uses a long-term growth rate of 3.72% [*sic*]." Tr. vol. 7, 353. First, witness Morin again carelessly cut-and-paste his DEP rebuttal testimony without changing the page references or calculations to reflect witness Ellis's DEC testimony. But more importantly, as pointed out in the DEP case, those two different growth rates correspond to two different estimates: the long-term growth rate for the utility sector alone—1.70%—and the long-term growth rate for the market as a whole—3.71%. As witness Ellis explained in his testimony, the utility sector historically has grown at the rate of inflation—1.70%—while the economy as a whole has grown at the long-term per-capita nominal GDP growth rate—3.71%. Tr. vol. 15, 747-49, 795.

Third, witness Morin suggested that witness Ellis's critique of economic forecasts from Blue Chip Economic Indicators (BCEI) was inconsistent with his later use of economic forecasts from "several institutions" to develop his market risk premium (MRP). Tr. vol. 7, 353. But witness Ellis's critique was specific to BCEI, whose forecasts he did *not* use in developing his MRP. Tr. vol. 15, 753-60.

As explained in Section IV.C.2.a.ii. above, witness Morin relied exclusively on BCEI to develop his supplemental risk-free rate. BCEI, however, has consistently overestimated U.S. Treasury yields for decades, making them an unreliable source for such a key input into cost-of-equity calculations. Tr. vol. 15, 753-60. In developing his MRP, witness Ellis used forecasts for per-capita GDP growth, not forecasts of U.S. Treasury yields, and did not use forecasts from *BCEI* but from three government agencies: the Congressional Budget Office (CBO), the Energy Information Administration (EIA), and the Social Security Administration (SSA). *Id*. at 793-95.

In sum, the three "inconsistencies" that witness Morin purported to identify in witness Ellis's testimony were not in fact inconsistencies. On the contrary, witness Morin's failure to understand these basic aspects of witness Ellis's testimony casts further doubt on the credibility of his recommended ROE.

E. <u>Conclusion</u>

As noted at the outset, DEC has not met its burden to establish that the authorized rate of return on equity should be set at 10.4%. Such an excessive return would represent an unjustifiable transfer of wealth from ratepayers to the Company's shareholders and is out of step with the returns investors expect from investments of comparable risks. Witness Morin's testimony was inconsistent with his published work and relied on inputs that biased his results upwards. Witness

Ellis's approach was more thorough, transparent, internally consistent, and supported by best practices in finance. If the Commission's ultimate decision on the allowed ROE for DEC is informed by the recommendations of witness Ellis, DEC's ratepayers would save hundreds of millions of dollars per year while still allowing DEC access to the capital markets and the ability to maintain its current credit rating.

V. THE COMMISSION SHOULD REJECT THE PIMS SETTLEMENT AND DEC'S PBR APPLICATION, CONVENE A POLICY GOALS DOCKET, AND REQUIRE AN INDEPENDENT MANAGEMENT AND FINANCIAL AUDIT.

In addition to determining whether a performance-based ratemaking (PBR) application "would result in just and reasonable rates, is in the public interest, and is consistent with the criteria established in [G.S. 62-133.16] and rules adopted thereunder," N.C.G.S. § 62-133.16(d)(1), the Commission can consider whether that application, among other things, advances certain policy goals. *Id.* § 62-133.16(d)(2). At bottom, these policy goals must promote "expected achievement of operational efficiency, cost-savings, or reliability of electric service that is greater than" what the law already requires. *Id.*

The Agreement and Stipulation of Settlement on Performance Incentive Mechanisms, Tracking Metrics, and Decoupling Mechanism (PIMs Settlement) between DEC, the Carolina Industrial Group for Fair Utility Rates III (CIGFUR), and Public Staff – North Carolina Utilities Commission (Public Staff) is a non-unanimous stipulation resolving certain aspects of DEC's PBR application as between the stipulating parties. Accordingly, the following applies:

> A stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding.[12] The PIMs Settlement Would Not Result in Just and Reasonable Rates and Is Not in the Public Interest.

The PIMs Settlement and the PBR application should be rejected as they do not advance cost containment public policy goals, do not result in just and reasonable rates, and are therefore not in the public interest.

When determining whether a PBR application would result in just and reasonable rates and advance the public interest, it is important to consider the overall aims and objectives of PBR under HB 951. At bottom, PBR is designed to better align utility profitmaking incentives with desired legislative, regulatory, and public policy outcomes, which DEC acknowledges include cost containment and affordability. Tr. vol. 11, 252-54. Ideally, multi-year rate plans (MYRPs) would incentivize cost containment through a strong revenue cap, *see* tr. vol. 15, 891, and advance other preferred outcomes by reducing regulatory lag, which would in turn potentially provide a utility with “better certainty on cost recovery for desirable actions like…affordability measures,” *id*. at 898. Decoupling would

[12] *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice*, In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Docket No. E-7, Sub 1214, at 27-28 (Mar. 31, 2021) (internal quotation marks omitted) (citing *State ex rel. Utilities Commission v. Carolina Utility Customers Ass’n, Inc.*, 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998)).

advance energy efficiency and in turn cost savings by severing the link between electricity sales and utility revenues. *See id*. at 892-93.

On paper then, PIMs would accomplish PBR's overarching aims and objectives most directly by tying "a portion of utility's revenue to its performance," fulfilling desired legislative, regulatory, and/or public policy outcomes. NCJC *et al*. Bateman Stillman Abernathy Rebuttal Cross Exhibit Cross Ex. 1, at 23 (NCJC *et al*. Bateman Stillman Abernathy Ex. 1) (Official Ex. vol. 16, 519). In the instant proceeding, designing PIMs that contain costs and promote affordability is critical given DEC's sizeable base case and MYRP revenue requirements, which are driven in large part by costly, misaligned, and largely unjustified distribution grid investments, and the excessively high 10.4% ROE that DEC seeks to apply to these investments. Tr. vol. 15, 675-834, 847-48, 858-61. However, overcoming the prevailing capital expenditure bias that exists under traditional cost of service ratemaking and meaningfully incentivizing cost containment and affordable decarbonization instead would ultimately require DEC to tie a "significant portion of…[its] revenues" through its proposed PIMs in order to achieve these cost containment and affordability objectives. NCJC *et al.* Bateman Stillman Abernathy Ex. 1, at 23 (Official Ex. vol. 16, 519).

In relevant part, N.C.G.S. § 62-133.16(c)(4) provides "that the total of all potential and actual PIM incentives or penalties . . . [cannot] exceed one percent (1%) of the electric public utility's total annual revenue requirement that is used to fix rates during the first year of the MYRP pursuant to G.S. 62-133."[13] DEC witness Melissa Abernathy's[14] pre-filed direct testimony indicates that for purposes of the PIM incentive cap in this proceeding, 1% of DEC's originally proposed revenue requirement would be $56 million. Tr. vol. 12, 113. Since then, DEC has not filed any analyses or testimony recalculating the PIM incentive cap in accordance with several settlement agreements that adjust the Company's original revenue requirement proposal. Therefore, given the significant rate increases DEC projects over the next three years,[15] it is even more important that DEC's proposed PIM rewards and penalties maximize the PIM incentive cap to the greatest extent possible.

Unfortunately, the PIMs Settlement fails to maximize the PIM incentive cap, which on its own forecloses any possibility that the proposed PIMs could meaningfully advance cost containment and affordable decarbonization. By rate year 3, the PIMs Settlement has a maximum incentive upside and downside potential of +/- $15 million. Tr. vol. 11, 202. Based off DEC's own analysis, there is at least $41 million worth of additional, potential PIM rewards or penalties that

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[13] This cap "exclude[es] any revenue requirement for the capital spending projects to be placed in service during the first rate year, where the PIM is approved" and any "incentives related to demand-side management and energy efficiency measures pursuant to G.S. 62-133.9(f)." N.C.G.S. § 62-133.16(c)(4).

[14] On May 17, 2023, DEC filed a motion to (1) substitute witness Abernathy for DEC witness Kathyrn Taylor and (2) allow witness Abernathy to adopt witness Taylor's pre-filed direct testimony, which the Commission granted in its Order Accepting Substitution of Witness and Allowing Adoption of Testimony that was issued on May 25, 2023.

[15] DEC's original application projected a 17.9% increase in residential rates. Application to Adjust Retail Base Rates and for Performance-Based Regulation, and Request for an Accounting Order, at 21. DEC witness Morgan Beveridge filed settlement testimony exhibits on August 24, 2023, in support of the Agreement and Stipulation of Partial Settlement that provide revised rate increase estimates for each of the customer classes for *each* of the MYRP rate years, however, these exhibits do not provide cumulative, projected rate increases over the *entire* MYRP term for each of the customer classes.

could have been directed to incentivize cost containment and affordable decarbonization, and which the PIMs Settlement fails to deploy.

DEC contends that the PIMs Settlement "represents a just and reasonable resolution of the Company's first PIM proposals and tracking metrics" and "reflects a thoughtful and measured set of PIMs that are reasonable and in the public interest." *Id*. at 210. More specifically, DEC witnesses represented on the stand that the PIMs Settlement's limited, aggregate PIM penalties and rewards reflect the Company's desire "to learn from the [PBR] process…to kind of slowly step in and learn from our experience." *Id*. at 270.

However, it is unclear how the Company squares this ostensibly cautious approach with the projected $12.28 billion in MYRP and non-MYRP capital spending over the next three years, especially given the significant concerns the Public Staff has raised regarding DEC's ability to execute many of its proposed MYRP and non-MYRP projects. Tr. vol. 12, 896, 901-05, 906-10. This justification is also undermined by the Company's firm opposition in the PBR rulemaking proceeding to the convening of a PIMs policy goals docket prior to the filing of a PBR application.[16] Indeed, a policy goals docket would have provided precisely the measured and deliberate approach the Company now asserts is its intent.[17] Given the significant projected rate increases and likely bill impacts if DEC's PBR application were to be approved, DEC's failure to maximize the PIM incentive cap and adequately justify this decision arguably amounts to an abdication of its

[16] *Order Adopting Commission Rule R1-17B*, In the Matter of Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities, Docket No. E-100, Sub 178, at 7-8 (Feb. 10, 2022) (PBR Rulemaking Order).
[17] *See* infra V.C for more discussion on the value and potential structure of a policy goals docket.

responsibility to assure that no customer or group of customers is unreasonably harmed. *See* N.C.G.S. § 62-133.16(d)(1)a.

Putting to the side DEC's failure to maximize the PIM incentive cap, the PIMs Settlement fails on the merits to meaningfully advance cost containment and affordable decarbonization. The proposed PIMs also fail to adhere to the PIM principles developed in the North Carolina Energy Regulatory Process (NERP),[18] which DEC agrees provides valuable guidance on PIMs design best practices. *See* tr. vol. 16, 269, 295, 349, 361. Under the NERP PIM principles, a utility must first determine "whether a reward or penalty is necessary. Among other things, this inquiry rests on existing utility incentives (and disincentives), the existing regulatory environment, and the level of utility control over the desired outcome." NCJC, *et al*. Bateman Stillman Abernathy Ex. 1, at 23-24 (Official Ex. vol. 16, 519-20).

Should a utility determine that rewards or penalties are necessary, it must then design each PIM with the following considerations in mind:

- PIMs should advance public policy goals, effectively drive new areas of utility performance, and incentivize nontraditional methods of operating.
- PIMs should be clearly defined, measurable, preferably using available data, and easily verified.
- PIMs should collectively comprise a financially meaningful portion of the utility's earning opportunities.
- No adopted PIM should duplicate a reward or penalty created by another PIM or other legal or regulatory mechanism.

[18] NERP was a stakeholder process North Carolina Governor Roy Cooper convened to identify utility regulatory forms that would help support the clean energy transition. Tr. vol. 11, 143-44.

- PIMs should reward outcomes, not inputs. In other words, the NCUC should avoid using expenditures as PIM metrics unless the desired outcome is increased spending.

- PIMs with metrics not controllable or minimally controllable by the utility should be upside only… .

Id. at 24. "The utility should [also] track the overall performance for each adopted PIM or tracked metric, and, where possible, separately track the utility's performance in low-income counties, specifically Tier 1 and 2 counties." *Id*. at 9. "Once a PIM is established, it should be revisited on a regular basis to evaluate whether the selected metric, target, and incentive level are appropriate for achieving the outcome in question. If not, those parameters should be adjusted to improve performance." *Id*. at 24-25.

A. <u>DEC's PIM Proposals</u>

1. Time-Differentiated, Dynamic Rate Enrollment PIM.

DEC has not adequately demonstrated that the time-differentiated dynamic rate enrollment PIM (Rate Enrollment PIM) would meaningfully reduce peak loads and thereby defer traditional grid investments or that the proposed incentives under this PIM would adequately compensate the Company for eschewing returns from these deferred investments. With respect to the NERP PIM principles, the Rate Enrollment PIM is not clearly defined, and DEC has failed to meaningfully consider whether a reward or penalty is necessary given the existing regulatory environment and level of utility control over certain incremental customer enrollments.

Under the upside only Rate Enrollment PIM, DEC would receive a $5 reward for each additional customer that enrolled in a qualifying, time-differentiated, dynamic rate. Tr. vol. 11, 202-03. Compensation would be capped at 450,000 customers, which would result in a maximum PIM reward of $2,250,000 each rate year. *Id*. at 203. At present, the eligible rate schedules would include RSTC and RETC. PBR Policy Panel Ex. 1 at 1-2 (Official Ex. vol. 12, part 2 at 97-98).

DEC has not adequately demonstrated that the Rate Enrollment PIM would "encourage[] peak load reduction or efficient use of the system," N.C.G.S. § 62-133.16(d)(2), and thereby defer grid investments or that the proposed $5/customer incentive would leave DEC whole in light of these grid investment deferrals. At bottom, the Rate Enrollment PIM seeks to incentivize incremental customer enrollments in qualifying rate schedules, rather than winter peak load reductions. Said another way, the Rate Enrollment PIM would only reduce winter peaks to the extent enrolled customers curtail their usage.

To be sure, DEC estimates that "the average expected [w]inter peak reduction per enrolled customer…[would be] approximately ~0.21-0.31 kW," which it projects would deliver a current utility system benefit of approximately $70 to $80 per kW. PBR Policy Panel Ex. 1, at 2 (Official Ex. vol. 12, part 2 at 98). However, even if this range of estimates is accurate, the aggregate level of savings (and system benefits) are unknowns as DEC, among other things, has not filed any estimates of how many additional customers it anticipates will enroll in the qualifying rate schedules. Given this lack of data then, it is patently unclear whether the "estimated customer enrollment due to this PIM will be sufficient to forestall any grid investments that would otherwise be necessary," tr. vol. 15, 912, or whether the incentives it would receive "outweigh the utility's foregone earnings associated with the grid investment," *id*. at 912-13.

In addition, the Rate Enrollment PIM is not clearly defined. DEC has provided a broad range of (1) potential winter peak-load reductions per enrolled customer (kW/customer) and (2) potential system benefit(s) associated with this reduction ($/kW). PBR Policy Panel Ex. 1, at 2 (Official Ex. vol. 12, part 2 at 98). There is even less precision with respect to any future rate schedules that the Commission might approve as there is absolutely no data, estimates or otherwise, quantifying per customer load reductions and benefits attributable to those reductions.

Contrary to the NERP PIM principles, it is also unclear whether DEC has meaningfully considered whether some of the Rate Enrollment PIM rewards are necessary given the existing regulatory environment and concomitant lack of utility control. If the Rate Enrollment PIM were approved, DEC would receive a $5/customer reward for each additional customer that enrolled in a qualifying rate. Meaning if only one customer enrolled, DEC would receive $5. Given the Commission's recent order approving Duke Energy's revised net metering tariffs, there may be some new residential customers who seek to participate in net metering for the first time, and, if the bridge rate cap were met,[19] would then be

[19] Pursuant to a stipulation the Commission approved in its order, new residential customers who apply to participate in net metering would have the option for a period of time of enrolling in a proposed bridge rate as opposed to a RSTC rate. *Order Approving Revised Net Metering Tariffs*,

required to enroll in the Residential Solar Choice tariff and take service under the RSTC rate.[20] Therefore, even though those customers would be required to take service under RSTC rates and DEC would not have encouraged them to enroll in those rates for the specific purpose of reducing winter peak loads, DEC would nevertheless receive a $5 incentive for each enrollment. Additionally, DEC has not provided a current, annual "business-as-usual" baseline of enrollments in qualifying time-differentiated rates. Establishing such a baseline and prohibiting DEC from receiving a reward for enrollments at or below the baseline could at least avoid unjustified compensation to DEC for business-as-usual enrollments in time-differentiated rates. Given the requirement that at least a subset of new residential net metering customers take service under a RSTC rate and given there is likely a baseline of customer enrollments in qualifying time-differentiated rates each year, it is unreasonable that there is no floor or dead band on Rate Enrollment PIM rewards that takes these factors into account.

2. Reliability.

DEC's commitment to track and report the ten worst performing circuits on its system is inadequate and inconsistent with NERP PIM principles. Tracking and reporting system reliability at the zip-code or census tract level instead would better ensure "adequate, reliable and economical utility service [is provided] to all" DEC customers by helping to direct reliability improvements to the zip codes and census tracts where they would provide the most value. N.C.G.S. § 62-2(a)(3).

In the Matter of Investigation of Proposed Net Metering Policy Changes, Docket No. E-100, Sub 180, at 9-10 (Mar. 23, 2023).
[20] *Id.* at 41-42.

Pursuant to the PIMs Settlement, DEC must "provide an annual Circuit Performance Report that identifies the ten circuits with the worst combined score of SAIDI, SAIFI, and CAIDI." Tr. vol. 11, 209. The PIMs Settlement specifically provides that the report will give "equal weight to" SAIDI, SAIFI and CAIDI and "exclud[e] major event days." [21] In addition, this report would "include an analysis of each circuit's performance." *Id*.

While DEC's commitment to track and report reliability at a more granular level than the system and its identification of the specific metrics through which the ten worst performing circuits would be identified are all improvements from the status quo, the PIMs Settlement does not sufficiently prioritize monitoring potential system reliability disparities in different communities. This is contrary to the NERP PIM principle providing that utilities should track their performance in low-income communities.

In addition, depending on the number of circuits that are ultimately tracked, it is unclear whether this approach would provide DEC, the Commission, and stakeholders the necessary visibility into any potential service reliability issues experienced in all low-income communities, communities of color, or environmental justice (EJ) communities. Indeed, it is entirely possible (and in fact, one would hope) that the ten worst performing circuits will change over time.

Given these challenges, at a minimum, DEC should track and report SAIDI, SAIFI, and CAIDI at the zip-code or census tract level and report those results. This tracking and reporting would help the Company in identifying and addressing

[21] Agreement and Stipulation of Settlement on Performance Incentive Mechanisms, Tracking Metrics, and Decoupling Mechanism at 7.

any potential system reliability disparities that exist between EJ communities and non-EJ communities while avoiding any potential turnover issues.

3. Metrics A, B, and C.

DEC has not sufficiently demonstrated that Metric A would deliver cost savings. Metric A would reward DEC for exceeding certain net metering (NEM) interconnection thresholds relative to a three-year rolling average. Tr. vol. 11, 205. Net metering undoubtedly provides real value. However, DEC has not adequately demonstrated the "linkage between Metric A and cost savings." Tr. vol. 15, 913. While Metric A would help DEC save costs if net metered systems were "managed by the utility…to meet load and reduce peak[s]," to date, DEC has not filed any analyses or testimony in this docket establishing the "level of anticipated peak-shifting or saving benefits associated with this metric." Tr. vol. 11, 265-66. As NCJC, *et al*. witness Wilson highlights in her pre-filed direct testimony, Metric A would help contain costs "if the metric were changed to the number of DER projects that are interconnected in a year and enrolled in a utility or third-party program demand side management program." Tr. vol. 15, 913.

Similarly, DEC has failed to demonstrate how Metric B promotes cost savings. To the extent Metric B seeks to incentivize additional renewables for large customers, it is unclear whether it would achieve that goal, let alone save costs as "the programs that would be eligible under . . . [this metric] are already part of the utility's procurement plan (meaning these programs provide no additional benefits or regulatory surplus to ratepayers)."[22] *Id*. at 914. Moreover, at a deeper level, it is unclear whether Metric B even "advance[s] public policy goals…[or] effectively drive[s] new areas of utility performance," NCJC *et al*. Bateman Stillman Abernathy Ex. 1, at 24 (Official Ex. vol. 16, 520), as DEC has not clarified whether this PIM is actually intended to spur additional renewables for large customers, more customer enrollments, or large renewable customer program improvements.

Lastly, while the revised Metric C is largely a welcome addition, it should be revised to incorporate any Commission-approved upward adjustments to DEC's proposed utility-scale solar interconnection assumptions for the upcoming Carbon Plan/Integrated Resource Planning (CPIRP) proceeding. Tr. vol. 11, 206-07, 267. As revised, Metric C incentivizes utility-scale solar interconnections over and above DEC's current, modeled utility-scale solar interconnection assumptions for this year's CPIRP. *Id*. at 206-07. It is entirely possible that the Commission might adjust these assumptions upwards in the upcoming CPIRP proceeding (or other proceedings) given the facts on the ground and/or compelling new modeling results. Consistent with NERP PIM principles, incorporating Commission-approved adjustments would ensure Metric C's benchmarks are adjusted as appropriate to improve performance.

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[22] A regulatory surplus exists when customer purchases of clean energy (or its functional equivalent) lead to clean energy procurement or deployment over and above existing legal or regulatory requirements. *See Regulatory Surplus*, EPA, https://www.epa.gov/green-power-markets/regulatory-surplus (last visited June 7, 2023).

B. Given these deficiencies in the PIMs Settlement and the costly and largely unnecessary MYRP grid investments, the Commission should reject the PBR applicationand Adopt Witness Wilson'ss PIM Proposals.

If the Commission should choose to adopt a MYRP with modifications or require DEC to refile its PBR application, the Commission should also require DEC to modify its updated PBR application to include the PIM proposals set forth in NCJC, *et al.* witness Wilson's pre-filed direct testimony. Witness Wilson's PIM proposals maximize the PIM incentive cap and tie a "significant portion of…[DEC's] revenues" to the achievement of cost containment and affordable decarbonization. NCJC et al. Bateman Stillman Abernathy Ex. 1, at 23 (Official Ex. vol. 16, 519).

Pursuant to N.C.G.S. § 62-133.16(d)(3), the Commission must "issue an order approving, modifying, or rejecting the electric public utility's PBR application." In addition, "[i]f the Commission rejects the PBR application, it shall provide an explanation of the deficiency and an opportunity for the electric public utility to refile, or for the electric public utility and the stakeholders to collaborate to cure the identified deficiency and refile." *Id*.

Witness Wilson's symmetrical Fuel Cost PIM would advance the HB 951 policy goal of cost savings by incentivizing DEC to reduce its fuel costs. Tr. vol. 15, 925. Combatting fuel cost hikes has taken on even greater importance in recent years, with 2022 in particular marking the "single largest year-on-year increase in electric bills" nationwide, due in large part to "sustained high natural gas prices."[23] Indeed, DEC filed a fuel charge adjustment application earlier this year that initially would have resulted in a "17.99% increase on customers' bills" due to a "$999 million under-recovery" stemming from fossil fuel commodity price increases.[24] Pursuant to N.C.G.S. § 62-133.16(d)(3) and Commission Rule R8-55, an electric public utility can recover all its prudently and reasonably incurred fuel and fuel-related costs from its customers in annual fuel rider proceedings. As a result, the utility bears none of the ultimate risk if costs increase more than expected. *See* tr. vol. 15, 919.

Witness Wilson's proposed Fuel Cost PIM "would allow the utility to capture a share of the benefits if fuel costs turn out to be lower than expected and require it to bear the same share of the cost if they turn out to be higher than expected," with the annual reward or penalty potentially capped at $20 million. *Id*. at 921. By requiring DEC to bear some fuel cost risk, the PIM would incentivize DEC to operate its fossil fuel assets even more efficiently and operate more fuel free renewables, which would reduce costs. Using historical data, the Fuel Cost PIM sharing percentage could be set at a level "that would have triggered the cap 20% of the time if the PIM had been in place over the past ten years." *Id*. at 922.

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[23] Joe Daniel *et al*., RMI, Strategies for Encouraging Good Fuel-Cost Management 5 (2023), *available at* https://rmi.org/insight/strategies-for-encouraging-good-fuel-cost-management/.

[24] Direct Testimony of Sigourney Clark for Duke Energy Carolinas, In the Matter of Application of Duke Energy Carolinas, LLC Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustment for Electric Utilities, Docket No. E-7, Sub 1282, at 6 (Feb. 28, 2023). DEC and the Public Staff entered into an Agreement and Stipulation of Partial Settlement that reduced the immediate bill impact associated with this under-recovery, and which the Commission ultimately approved. *See* Order Approving Fuel Charge Adjustment, In the Matter of Application of Duke Energy Carolinas, LLC Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustment for Electric Utilities, Docket No. E-7, Sub 1282, at 18-19 (Aug. 23, 2023).

This proposal is also permissible under N.C.G.S. § 62-133.2 and Chapter 62 more generally. N.C.G.S. § 62-133.2(f) provides as follows:

> Nothing in this section shall relieve the Commission from its duty to consider the reasonableness of the cost of fuel and fuel-related costs in a general rate case and to set rates reflecting reasonable cost of fuel and fuel-related costs pursuant to G.S. 62-133. Nothing in this section shall invalidate or preempt any condition adopted by the Commission and accepted by the utility in any proceeding that would limit the recovery of costs by any electric public utility under this section.

Accordingly, the Commission has the obligation to consider the reasonableness of fuel and fuel-related costs in a general rate case. The Commission may also adopt conditions that limit the recovery of fuel and fuel-related costs. In addition, N.C.G.S. § 62-133.16 would not otherwise preclude a fuel cost PIM. Fuel cost reduction is a policy goal related to the "expected or anticipated achievement of operational efficiency [and] cost savings…greater than" existing state or federal requirements. N.C.G.S. § 62-133.16(a)(8). While fuel cost reduction has downstream environmental impacts, it is not a prohibited environmental standard for purposes of § 62-133.16(a)(8). Any reading to the contrary would unreasonably expand the reach of this prohibition.

DEC, in an inversion of the burden of proof, contends that NCJC, *et al*. has failed to adequately support this PIM proposal. However, the need and benefits of the Fuel Cost PIM are amply demonstrated by rising fuel costs nationwide, tr. vol. 15, 919, and the examples from several jurisdictions that require their utilities to share some fuel cost risk with their customers, *see id.* at 922,[25] which NCJC, *et al*. witness Wilson discusses in some depth in her pre-filed direct testimony. Witness Wilson also provided detailed recommendations regarding additional cost containment measures that the Fuel Cost PIM could help incentivize, along with a potential sharing factor, performance benchmarks, and PIM Incentive cap. *Id*. at 921-24.

Secondly, DEC argues that the Fuel Cost PIM would be unworkable as DEC does not have sufficient control over certain drivers of its fuel costs, tr. vol. 16, 298, while at the same time lauding its own fuel cost containment measures, *id*. at 296-98. While NCJC, *et al*. acknowledges that DEC, on its own, has no control over fuel commodity prices, and, absent any financial support it might provide for weatherization, no control over the weather impacts on customer load, there are several other drivers over which DEC has some control. Tr. vol. 15, 920 (noting that the Company can reduce its fuel costs by "negotiating more favorable fuel-price contracts, optimizing generation resources and market purchases to minimize costs," using batteries for energy arbitrage, and reducing its deployment of fossil fuels). Otherwise, DEC's fuel cost containment measures, which it takes great pride in, would be a futile, potentially costly misuse of its time and resources.

DEC also notes that a fuel cost PIM would be unnecessary given that the Commission can always disallow imprudent fuel costs. However, a fuel cost PIM would provide customers the guarantee of fuel rate relief with respect to fuel costs

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[25] *See also* Joseph Daniel, Electricity Customers Are Getting Burnt by Soaring Fossil Fuel Prices, RMI (June 23, 2022), https://rmi.org/electricity-customers-are-getting-burnt-by-soaring-fossil-fuelprices/.

that exceeded DEC's budget, all without the need for the Public Staff and other intervenors to investigate and recommend disallowance in potentially protracted litigation.

Additionally, DEC submits that the out-of-state fuel cost sharing mechanisms that NCJC, *et al*. cites are inapplicable. DEC contends that Hawaii has a fuel cost sharing mechanism in part because it "has the highest electricity retail price[s] of any state." Tr. vol. 16, 300. By DEC's logic, a fuel cost PIM would be inappropriate here because North Carolina's electric rates are lower than Hawaii's. However, Idaho has lower electricity prices than North Carolina[26] and employs fuel cost sharing mechanisms. Tr. vol. 15, 203.

Furthermore, for this argument to hold, Hawaii's high electric rates would have to be the dispositive factor justifying fuel cost sharing. It is far from a forgone conclusion that DEC's rates will remain comparatively low for the long-term. As highlighted previously, DEC experienced a $999 million under-recovery in this year's fuel rider proceeding because of coal and natural gas price increases. Moreover, Duke Energy's planned natural gas buildout will only increase its customers' exposure to fuel price volatility. With respect to the other factors DEC cites in opposition to fuel cost sharing, Hawaii is even more like DEC than DEC would probably want to admit. For example, DEC has presented no evidence that Hawaii's electric utilities have any more control over their fuel costs than DEC. In

[26] *Compare Idaho: State Profile and Energy Estimates*, U.S. Energy Information Administration, https://www.eia.gov/state/?sid=ID (last updated Apr. 20, 2023) (providing that Idaho has the third lowest electricity prices) *with North Carolina: State Profile and Energy Estimates*, U.S. Energy Information Administration, https://www.eia.gov/state/?sid=NC (last updated Dec. 15, 2022) (providing that North Carolina's electricity prices are the 11th lowest).

fact, given Hawaii's rather unique status as a geographically isolated state heavily dependent on imported oil for energy generation,[27] Hawaii arguably has even less control over its fuel costs than DEC.

Lastly, the fact that neither Idaho's fuel cost recovery rules nor Wyoming and Hawaii's perfectly mirror North Carolina's is ultimately immaterial. N.C.G.S. § 62-133.2(a)'s authorization of an annual fuel cost rider must be balanced with N.C.G.S. § 62-133.2(f), which explicitly preserves both the Commission's authority and obligation to assess the reasonableness and prudency of incurred fuel costs in a general rate case and authorizes the Commission to limit fuel cost recovery. Failure to balance these two provisions would render N.C.G.S. § 62-133.2(f) superfluous, which is contrary to long established principles of statutory interpretation. [28]

NCJC, *et al*.'s downside only Federal Savings Opportunity PIM would advance the HB 951 policy goal of cost savings by penalizing DEC for failing to take full advantage of federal tax and lending policies, including but not limited to investment tax credit (ITC) and production tax credit (PTC) adders under the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act direct-to-utility loan programs. *See* tr. vol. 15, 928-30. For example, incentivizing the full utilization of PTC and ITC adders, along with other federal tax and lending programs, would further reduce the costs associated with the construction or

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[27] *Hawaii*, *State Profile and Energy Estimates*, U.S. Energy Information Administration, https://www.eia.gov/state/analysis.php?sid=HI (last updated Mar. 16, 2023) (providing that Hawaii relies on oil for 62% of its energy generation needs).
[28] *See, e.g.*, *N. Carolina Dep't of Correction v. N. Carolina Med. Bd.*, 363 N.C. 189, 201, 675 S.E.2d 641, 649 (2009) (restating this general principle and affirming that related statutory provisions must be considered in concert).

generation of power from qualifying solar or storage assets, provided DEC sited those assets in designated energy communities, used U.S.-sourced components, and/or satisfied other requirements. *See id*. at 930. This in turn would make DER and renewables generally more cost competitive relative to other power supply alternatives, and thereby reduce overall customer costs. For example, “the value of the PTC can be increased 20% over the ‘bonus’ level available when prevailing wage and apprenticeship requirements are satisfied.” *Id*. The ITC’s value in turn “can increase 20 percentage points (or 66.7%) over the bonus level.” *Id*.

Operationally, this PIM could, for example, deny DEC “the benefit of excess costs when alternative projects with alternative tax credits assumptions are evaluated in a comprehensive fashion.” *Id*. at 931. Additionally, absent DEC providing adequate justification, it could penalize the Company for failing to monetize tax credits at the “rates prevailing in the tax credit transfer market when the credits are earned and cap the cost to ratepayers from the Company’s use of a regulatory asset until self-monetization at that level,” which would redound to the benefit of DEC customers. *Id*. As noted in witness Wilson’s testimony, industry experts “have indicated that [tax credit] transfers already have been selling at 90-92 cents” and may “settle at 95-96 cent[s] or even higher.” *Id*. at 906-07. While DEC has proposed creating a regulatory asset for certain ITC and PTC adders, this approach would reduce their value by charging customers a rate of return. *See id*.

DEC avers that the Federal Savings Opportunity PIM should be rejected given the prospect of disallowance, its regulatory asset proposal, the uncertainty surrounding these adders, and NCJC, *et al.'s* alleged failure to provide sufficient information supporting the PIM or explaining how it was designed. The Commission should reject these arguments. First, for reasons provided earlier, the potential for disallowance is not an effective substitute or replacement for a PIM. Second, DEC's preferred regulatory asset approach would require customers to pay carrying costs for unmonetized adders. *See id*. at 907. Third, IRA tax credits transfers are already being valued between 90 to 92 cents on the tax credit dollar. *Id*. at 906-07. Lastly, NCJC, *et al.* has provided ample information supporting its PIM. To the extent NCJC, *et al.* has not provided certain information, DEC, which is the utility, has equal or greater access to that information.

Similarly, NCJC, *et al*.'s NWA Projects Shared Savings Mechanism (NWA PIM) would advance the HB 951 policy goal of cost savings. *Id*. at 928. This PIM would help facilitate the identification and adoption of NWA solutions such as DERs that would address reliability, resiliency, and other grid needs and reduce carbon emissions, while obviating the need for costlier, traditional grid investments. Under the NWA PIM, DEC would share some of the total savings that are attributable to the adoption of NWA solutions with its customers. In addition, the Commission or an independent party "would approve the savings in total ratepayer costs attributable to each NWA solution deployed in a rate year relative to the traditional T&D investment it is delaying or replacing." *Id*. at 927. Savings from this PIM would flow back to ratepayers when rates are reset following the end of the MYRP period. *See id*. at 928.

C. <u>The Commission Should Convene a Policy Goals Docket.</u>

Many of the issues with DEC's PBR application stem from a lack of focus on relevant outcomes and policy goals. There is both a lack of sufficient evidence with respect to whether DEC's PIMs would meaningfully facilitate achievement of the identified outcomes and policy goals and whether certain outcomes even need to be incentivized. These issues could be addressed through the convening of a policy goals docket that builds upon the recommendations of intervenors in the PBR rulemaking proceeding, draws from examples from other jurisdictions, and informs the review of "any PBR application it receives in the next two to three years." Tr. vol. 15, 943. At a high level, the policy goals docket should provide an opportunity for (1) an "assessment of the incentives created by the current regulatory framework"; (2) an "explicit preliminary period focused on goal setting and outcome prioritization"; and (3) an "invitation to stakeholders to contribute [their] perspectives." *Id.* at 934.

Although the Commission initially declined to adopt a requirement for a policy goals docket in Commission Rule 1-17B, it noted in its Order Adopting Commission Rule R1-17B that "the Commission may choose to initiate dockets to set policy goals for PBRs if it determines in the future that such dockets would be useful."[29] This current proceeding demonstrates the usefulness of such dockets going forward. Having a policy goals docket would allow for stakeholder development of consensus policy goals that the Commission could consider in advance of a future (or re-filed) PBR application, along with supporting the

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[29] PBR Rulemaking Order at 14.

assessment and refinement of consensus policy goals and PBR outcomes on an ongoing basis. By bringing together the shared expertise and perspectives of DEC, regulators, and other stakeholders in a neutral, formal setting, the risk that any one approved policy goal was not sufficiently needed or supported by the evidence would be greatly diminished. A policy docket would also provide the Commission with the ability to clarify before a PBR application is filed which policy goals it seeks to prioritize, allowing parties to focus on PIMs that advance those goals.

As for the specifics, Rule R1-17B(g) provides that "[t]he Commission will establish the procedure for the annual review and issue an order setting forth the procedure based on requirements of this Rule." Accordingly, consistent with this provision, the Commission could open a permanent policy goals docket and issue an order consolidating that docket with the Rule R-17B(g) annual review. However, the content and duration of the initial policy goal stakeholder process would likely hinge on the Commission's order in this proceeding. If the Commission were to require DEC to re-file its PBR application, the Commission could establish a streamlined stakeholder process for the purpose of curing the deficiencies the Commission identified in DEC's PBR application and facilitating the re-filing of a cured PBR application, consistent with N.C.G.S. § 62-133.16(d)(3).

If the Commission were to either accept or reject DEC's PBR application outright, the Commission's order consolidating the two proceedings could provide for a longer, initial stakeholder process, the content and duration of which could also govern the development of new policy goals in future MYRP periods and

PBR applications unless the Commission ruled otherwise. If the Commission were to require DEC to refile its PBR application, this process could also inform the structure of any stakeholder processes following the Commission's approval of DEC's cured application. For example, this full stakeholder process could entail Commission organized workshops to foster shared learnings and help facilitate consensus policy goals that would inform any PBR mechanisms included in future PBR applications.

At a high level, this stakeholder process could mirror the process in Minnesota and Connecticut. There, the Minnesota Public Utilities Commission established a "goals-outcomes-metrics process as an effective method to gather stakeholder input and develop performance metrics." NCJC, *et al.* Bateman Stillman Ex. 1, at 51 (Official Ex. vol. 16, 547) (internal quotation marks omitted). In Connecticut, a recent Connecticut Public Utility Regulatory Authority (PURA) ruling "adopted four goals, five foundational considerations and prioritized nine outcomes to guide development of PBR reforms." Tr. vol. 15, 937 (internal quotation marks omitted). Importantly, PURA's PBR reform order specifically invites and encourages stakeholder feedback and contributions during this next phase of PBR reform activities. *See id*.

Following the Commission's adoption of policy goals and approval of a PBR application that incorporated those goals, the Commission could then track and assess utility achievement of those goals on an ongoing basis through the mechanisms provided in Rule R1-17B(g) and (f) and work with the utility and other stakeholders to translate these reports and outputs into more user-friendly scorecards for the general public to review. In addition, the Commission could conduct or require additional reporting and tracking of policy goal performance. Stakeholders could file comments or letters in the consolidated annual review docket that assess utility achievement of approved policy goals and recommend potential modifications to those goals. In the Commission's discretion, expert witness hearings could be scheduled to resolve issues of fact stemming from the assessment and recommended modification of policy goals. Depending on utility performance, facts on the ground, and any Commission orders, directives, or rulings regarding the same, stakeholder collaboration through workshops (and any other means the Commission identified) for the purpose of developing new policy goals could proceed concurrent to the assessment and refinement of existing policy goals already occurring in the consolidated annual review.

D. The Commission Should Require an Independent Management Audit and Financial Audit

Given that DEC (along with other regulated utilities) is protected from competition by virtue of its exclusive franchise, an independent management audit and financial audit would help provide increased "visibility into…utility[] performance…and decision-making." Tr. vol. 15, 942.

Pursuant to N.C.G.S. § 62-37, the Commission, on its own initiative, enjoys broad authority to "investigate and examine the condition and management of public utilities or of any particular public utility." *Id.* § 62-37(a).[30] These investigations may be conducted without hearings; however, if the Commission

[30] *See, e.g.*, *State ex rel. Utilities Comm'n v. Edmisten*, 299 N.C. 432, 443, 263 S.E.2d 583, 591 (1980) (finding that the Commission had the authority to "direct the applicant Nantahala to furnish such information" regarding "a roll-in device, or technique, for rate-making computation").

wishes to issue an order, it must provide the affected utility and any other affected parties with notice and an opportunity to be heard. *See id.* The Commission must also report its investigation findings and recommendations to the Governor and Council of State if it determines that the following applies:

> [T]he public interest shall be served by an appraisal of any properties in question, the investigation of any particular construction, the audit of any accounts or books, the investigation of any contracts, or the practices, contracts or other relations between the public utility in question and any holding or finance agency with which such public utility may be affiliated.

Id. § 62-37(b). Notwithstanding the above, "the Commission is authorized to initiate a full and complete management audit of any public utility company once every five years, by a competent, qualified, and independent firm." *Id.* Thus, a G.S. § 62-37 investigation or audit would be more comprehensive and could therefore uncover greater cost savings than the annual review contemplated under Commission Rule R1-17B(g), the reporting required under R1-17B(h), and/or a Commission review conducted pursuant to N.C.G.S. § 62-133.16(e).

As witness Wilson details in her pre-filed direct testimony, a financial audit could deepen stakeholders' understanding of DEC's fuel cost containment measures. A management audit on the other hand could help improve the efficiency of utility operations. In Hawaii, a management audit "identified operational inefficiencies amounting to annual savings of roughly $25 million." Tr. vol. 15, 942. In Illinois, each major utility must be audited within six months on certain capital spending, "utility efforts to optimize reliability and resiliency," MYRP baselines, and potential "deficiencies that could impact the planning process." *Id.*

at 943. Drawing on these examples could help inform a potential management audit and financial audit of DEC and in turn identify potential cost saving opportunities.

RELIEF REQUESTED

For the foregoing reasons, NCJC, *et al*. respectfully urges the Commission to do the following:

1. Reject DEC's PBR application, or in the alternative, modify DEC's PBR application to incorporate NCJC, *et al*.'s recommendations and the alternative PIM proposals NCJC, *et al*. witnesses Gennelle Wilson, David Hill, and Jake Duncan proposed.

2. Reject DEC witness Morin's recommended rate of return on equity (ROE) and adopt NCJC, *et al*. witness Ellis's recommended allowed ROE instead.

3. Initiate a working group to redesign the Company's cost-benefit analysis for grid modernization and DERs.

4. Require the Company to conduct two or more NWA pilot projects, with at least one focusing on an environmental justice community.

5. Initiate an investigation into distribution system planning to establish stakeholder supported (i) grid modernization objectives, (ii) reporting and data sharing requirements for regulated electric utilities, (iii) NWA methodology and proposal requirements, (iv) community engagement plan, and (v) exploration of the EJ aspects of grid modernization.

6. Require DEC to report reliability data at the census tract and nine-digit zip-code level—comprised of aggregated and anonymized customer premise level data—in order to investigate potential disparities in reliability services.

7. Require the Company to use its existing grid hosting capacity stakeholder process to evaluate the fourteen decision points for an effective hosting capacity analysis as described by Interstate Renewable Energy Council; collaborate with stakeholders to add sociodemographic, energy burden, and other environmental justice indicators on top of its planned grid hosting capacity map; and include load hosting capacity in addition to generation hosting capacity in its grid hosting capacity.

8. Require the Company to update the proposed grid modernization plan investments to account for federal funds through the IRA and Infrastructure Investment and Jobs Act and require the Company to work with stakeholders to identify at least two target initiatives that address environmental justice through multiple DERs as non-wire solutions.

9. Convene a Policy Goals docket.

10. Require an Independent Management Audit and Financial Audit.

11. Approve the Affordability Settlement.

Respectfully submitted this 11th day of October, 2023.

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CERTIFICATE OF SERVICE

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

This the 11th day of October, 2023.

/s/ David Neal
David Neal