BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 178

In the Matter of: Performance Based Regulation of Electric Utilities	)	**COMMENTS AND PARTIAL PROPOSED RULES SUBMITTED ON BEHALF OF NORTH CAROLINA JUSTICE CENTER, NORTH CAROLINA HOUSING COALITION, SIERRA CLUB, AND SOUTHERN ALLIANCE FOR CLEAN ENERGY**

I. <u>Introduction</u>

After more than two years of contentious debate[1]—and in the absence of an inclusive stakeholder process[2]—the legislature passed House Bill 951 (HB951), authorizing the Commission to approve a new type of incentive regulation for North Carolina electric public utilities. <u>See</u> 2021 N.C. Sess. Law 165, Part II. However, without careful implementation by the Commission, the multiyear ratemaking provisions in HB951 risk producing an outcome that is unduly skewed towards the benefit of utility shareholders while placing ratepayers at risk.[3] In multiple ways, the law protects utility revenues, accelerates utility cost recovery, and contains

[1] Catherine Morehouse, *North Carolina eliminates controversial Duke multiyear rate plan from energy legislation*, Utility Dive (Oct. 31, 2019) (https://www.utilitydive.com/news/north-carolina-eliminates-controversial-duke-multiyear-rate-plan-from-energ/566246/).

[2] John Downey, *Sponsors defend utility regulation reform bill as Gov. Cooper, others express opposition,* Charlotte Business Journal (June 18, 2021) (noting that the process for drafting HB951 "excluded environmental and public interest groups while engaging the utilities, industrial customers, solar industry representatives, manufacturers and merchant groups in a five-month stakeholder process"). (https://www.bizjournals.com/charlotte/news/2021/06/18/sponsors-defend-utility-regulation-reform-bill.html).

[3] John Downey, *New regulatory law puts NC among nation's friendliest states for utility investors*, Charlotte Business Journal (Oct 18, 2021) (reporting that HB951 puts the North Carolina in the top 10 out of 53 jurisdictions in the nation for utility-friendly regulatory environments," according Regulatory Research Associates Inc., a ranking based on "'constructive' regulatory practices are. The more constructive a state's regulatory regime, the lower the risk for utilities and their investors").

provisions that could put upward pressure on utility rates. HB951 is missing common provisions that would automatically incentivize utilities to become more efficient and innovative, one of the main purposes behind performance-based regulation (PBR) reforms. Importantly, the new law also limits the potential of using the PBR framework to transform the utility business model away from traditional cost-of-service, rate of return ratemaking (COS).

While HB951 missed an opportunity to put North Carolina in the vanguard of states making significant progress on utility regulatory reform, this rulemaking proceeding provides the Commission with an opportunity to better align utility incentives with ratepayer interests and public policy goals established by the General Assembly. Through this rulemaking and its ongoing oversight, the Commission can ensure that North Carolina's PBR regime protects ratepayers, enhances affordability for low-income customers, promotes carbon reductions, promotes deployment of low-cost distributed energy resources and energy efficiency, and serves the larger public interest.

The new law does not disturb the Commission's authority "to regulate public utilities generally, their rates, services and operations, and their expansion in relation to long-term energy conservation and management policies and statewide development requirements" in accordance with the policies spelled out in the Public Utilities Act. N.C. Gen. Stat. § 62-2(b). As the Commission develops rules for PBR, it should remain guided by the declarations of public policy set forth at the beginning of the Act, requiring "fair regulation of public utilities in the interest of the public," with particular attention to the requirement to:

> …assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills…

N.C.G.S. § 62-2(a)(1) and (3a). Existing law also declares that it is the public policy of the state to "promote adequate, reliable, and **economical** utility service to all of the citizens and residents of this state." N.C.G.S. § 62-2(a)(3)(emphasis supplied). Finally, the new law does not disturb the longstanding requirement that rates for utility service be "just and reasonable" and that service be "adequate, efficient, and reasonable." N.C.G.S. § 62-131. The Commission has the authority to shape the implementation of this law so as to retain the historic regulatory balance between the utilities and the public interest and better align utility incentives with the goals of affordability and carbon pollution reduction.

The Commission's Order establishing this docket seeks input on four listed topics for PBR rulemaking set forth in N.C. Gen. Stat. § 62-133.16(j) as well as "any other relevant issues that the Commission must address to implement PBR." Order Requesting Comments and Proposed Rules, Docket No. E-100, Sub 178 (Oct. 14, 2021). NC Justice Center, NC Housing Coalition, Sierra Club, and Southern Alliance for Clean Energy (SACE) primarily focus these comments and partial proposed rules on the first two issues: "(1) The specific procedures and requirements that an electric public utility shall meet when requesting approval of a PBR application; and (2) The criteria for Commission evaluation of a PBR application." Id. In addition, these comments place HB951 in the broader context of utility regulatory reform and highlight the importance of affirmative Commission action to make the policy goals listed in the legislation a centerpiece of its implementation.

The included partial proposed rules[4] provide an outline of Commission rules that would be needed to implement the PBR provisions of HB951. In most cases, the partial proposed rules outline the types of rules that will be needed for implementing PBR, which will require further elaboration and refinement. For rules addressing Performance Incentive Mechanisms (PIMs) and Decoupling, the partial proposed rules contain more details for Commission consideration. Given the complexity of PBR and the interplay of PBR with the technical conference regarding projected transmission and distribution expenditures, the upcoming Carbon Reduction plan, and the Affordability Collaborative, NC Justice Center, NC Housing Coalition, Sierra Club, and SACE recommend that the Commission commit to a supplemental rulemaking process to continue after February 10, 2022 and before accepting an application for a multiyear rate plan.

These comments and partial proposed rules have been developed with the assistance of Ronald Binz, former chair of the Colorado Public Utilities Commission and one of President Obama's nominees for Commissioner and Chair

[4] The Partial Proposed Rules follow the conclusion of these comments.

of the Federal Energy Regulatory Commission.[5] Ronald Binz has decades of experience in the field of regulatory reform and has testified or consulted on PBR and decoupling issues in numerous dockets around the country.[6]

II. Incentive Regulation

"All regulation is incentive regulation."[7] Any method of regulation provides incentives, whether explicit or not, that affect the behavior of utilities. The new realities of the electric power sector, including the proliferation of distributed energy resources (DERs) and the urgent need to eliminate carbon pollution, mean that utilities must modify their traditional business model. Utilities should be regulated in a way that provides incentives to achieve desired public policy goals, something that traditional cost of service regulation does not provide.

A. Cost of Service Regulation

Regulated utilities have historically operated under the cost-of-service regulation model, under which the utility's profit is determined largely based on the size of the utility's capital investments. So "to the extent a utility's rate or return exceeds the cost of capital, electric utilities [under cost of service regulation] have

[5] Ronald Binz's complete curriculum vitae is attached as Exhibit 1.
[6] A list of Ronald Binz's Recent Experiences relating to PBR is attached as Exhibit 2.
[7] David Littell, et al. *Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation*, Regulatory Assistance Project (RAP) at 1 (2017) (citing Bradford, P. (1989). Incentive Regulation from a State Commission Perspective. Remarks to the Chief Executive's Forum).

an incentive to make excessive capital investments...[which can become] a goal in itself."[8] This has created

> strong financial incentives to increase rate base and electricity sales. Many of the recognized shortcomings of COS regulation can be traced to these financial incentives. They create a disincentive to utilize cost-effective DERs to reduce utility system use and avoid new capital investments.[9]

"Under the current system, utilities make more money by increasing their electric sales, which dis-incentivizes increased energy conservation."[10] In addition, riders allow electric utilities to pass along cost increases as those costs are incurred, reducing the traditional "regulatory lag" that provided some counter-balancing incentive for electric utilities to operate more efficiently between general rate cases.

B. Performance Based Regulation

Reformed regulation should reward public utilities for producing the outputs and achieving the policy goals that society requires while maintaining affordability of essential electric utility service. Ideally, PBR can provide "a regulatory framework to connect goals, targets, and measures to utility performance, executive compensation, and investor returns" that can be tied to particular policy

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[8] A Lowry, M., and T. Woolf, *Performance-Based Regulation in a High Distributed Energy Resources Future,* Future Electric Utility Regulation series, Lawrence Berkeley National Laboratory, LBNL-1004130 at 13 (2016).

[9] Lowry 2016 at 6.

[10] NERP Fact Sheet, Performance Based Regulation: Aligning Utility System Performance with Regulatory or Public Policy Goals at 1 (2020). NERP Fact Sheet Attached as Exhibit 3.

goals with incentives (Performance Incentive Mechanisms, PIMs).[11] PIMs typically have four components: (1) "Regulatory policy goals that specify certain performance areas of interest, as well as objectives for those areas (2) Metrics that provide detailed information about the utility's operations in the specified areas of interest (3) Targets that reflect performance goals, as measured by the metrics (4) Financial incentives (rewards and/or penalties) that are based on the utility's performance relative to the target."[12]

Multiyear rate plans are a common element of PBR plans, and they usually include an attrition relief mechanism (ARM) that allows "revenue (or rates) to grow in the face of cost pressures, without linking relief to a utility's *specific* costs."[13] This mechanism might also be called a "Revenue Adjustment Mechanism" (RAM) that applies each year of an MYRP. It usually takes the form of an index that is <u>independent of the utility's actual costs</u>, that accounts for inflation and recognizes industry-wide changes in productivity. "Revenue decoupling is often added to sever short-term links between a utility's revenue and electricity sales," which has the potential to realign utility incentives to support enhanced deployment of low-cost energy efficiency and other distributed energy resources.[14] As a general matter, a multi-year rate plan will likely be less successful if it applies for a relatively

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[11] David Littell, et al. *Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation*, Regulatory Assistance Project (RAP) at ix-x (2017).
[12] Lowry 2016 at 19.
[13] Lowry, Makos, and Deason, et al., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkely National Laboratory at 2.1 (July 2017) (italics added)
[14] <u>Id</u>. (citing Lazar, J., Weston, F., and Shirley, W., *Revenue Regulation and Decoupling: A Guide to Theory and Application*, Regulatory Assistance Project (Nov. 2016)).

short period of time, clings to rate base regulation when setting the annual price changes, or minimizes the revenue importance of performance measures.

Because traditional regulation sets allowed earnings based on the value of a utility's rate base, this style of regulation produces an inherent bias towards capital investment to meet system needs. For example, utilities are incentivized to deploy capital-intensive solutions to distribution and transmission issues instead of potentially lower-cost solutions that might include, for example, distributed energy resources (DERs). Utilities naturally develop a preference for utility-owned resources in contrast to purchasing power or non-wires alternatives. Stated another way, under COS regulation, utilities do not earn a "return" on expenses in the same way they do with rate base capital investment. This bias is not overcome simply by adopting revenue decoupling and it is not sufficiently mitigated by the addition of PIMs to traditional COS regulation. Putting "expense-like" solutions on an equal footing with "capital-like" solutions requires a fundamental change in the way utilities are compensated. Obviously, HB951 does not attempt to overcome this bias.

For that reason, PBR regimes often use a "revenue-cap" compensation model. The revenue cap can directly address the bias in COS ratemaking by paying a utility for the delivery of an outcome without reference to whether the outcome was achieved with any particular mix of capital and expenses. As a result, a PBR regime using a revenue cap compensation structure will focus on total expenses instead of capital expenses and operating expenses separately. This puts lower-cost "non-wires alternatives" on more nearly the same footing as utility capital investment. By selecting the lower-cost solution instead of the capital-intensive solution, a utility regulated under a revenue cap will increase earnings.

By reducing regulatory lag, decoupling revenue from sales, and providing additional assurances that the utility will have predictable revenue, the risk to under-recovery of targeted revenues is mostly eliminated. Since lower risk should result in a reduced cost of capital, commissions are justified in reflecting this effect by adjusting the utility's capital structure or reducing the allowed return on equity to account for reduced risks to the utility.[15]

III. PBR under HB951

HB951 inches towards a better framework for utility regulation without fully embracing a new paradigm. Part II of Session Law 2021-165 fails to include some of the most important and common features of incentive regulation adopted and under consideration in other states, such as a longer effective period, an ARM based on an index that is independent of the utility's costs, and a "consumer dividend" that creates ratepayer benefits. The multi-year rate period is limited to only three years; rate making relies on traditional COS regulation; and the year-to-year changes in allowed revenues are tied directly to the utility's additional investment. In other words, HB951 maintains traditional COS regulation at the heart of its attempt to create "performance-based regulation." That said, with the proper guardrails, carefully targeted performance incentives, and Commission oversight, the legislation may provide some improvement over traditional cost-of-

[15] See, Revenue Regulation and Decoupling at 36-39.

service regulation as practiced in North Carolina, even if it is not truly "performance-based regulation."

In adopting PBR rules pursuant to HB951's directives, the Commission should build on the extensive work completed by participants in the North Carolina Energy Regulatory Process (NERP). The NERP was comprised of a diverse group of stakeholders—including utilities, utility and environmental regulators, low-income advocates, large electricity customers, municipalities and clean energy advocates—convened by the North Carolina Department of Environmental Quality (DEQ) pursuant to recommendation B-1 in DEQ's Clean Energy Plan.[16] That recommendation was to "launch a North Carolina energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st century public policy goals, customer expectations, utility needs, and technology innovation." Id.

The NERP stakeholders evaluated, among other things, adoption of a performance-based regulatory framework. A subset of stakeholders including clean energy advocates, low-income advocates, utilities, and others participated in a study group focused on PBR. Although the PBR study group did not reach full consensus on a suite of recommendations, the group produced a package including a fact sheet, a regulatory guidance document, proposed PBR legislation and case studies. These work products reflect the hard work and thoughtful input of a broad range of stakeholders, and accordingly, should be taken into

[16] NERP PBR Fact Sheet at p. 3, supra note 10 (Ex. 3).

consideration by the Commission as it develops rules to implement the PBR provisions of HB951. The PIMs recommendations in the attached partial proposed rules relating to DERs, energy efficiency, and reduction in low-income energy burdens are informed by the regulatory guidance from the final PBR Study Group Work Products report.[17]

A. Retention of Cost of Service Regulation

As previous noted, the PBR regime in HB951 is unusual in comparison with leading examples of PBR from other states in that it prescribes continued adherence to most all aspects of cost-of-service regulation. For example, year-to-year changes in allowed revenues are determined explicitly by the standard COS metric of invested capital. Further, the statute allows for performance-based regulation, “so long as the Commission allocates the electric public utility's total revenue requirement among customer classes based upon the cost causation principle.” N.C. Gen. Stat. § 62-133.16(b). The “cost causation principle” is defined as the “establishment of a causal link between a specific customer class, how that class uses the electric system, and costs incurred by the electric public utility for the provision of electric service.” N.C. Gen. Stat. § 62-133.16(a)(1).

This explicit COS framework makes it difficult for the Commission to fully embrace the most transformative elements of PBR, because the ultimate incentive structure remains tied to “costs incurred” by the utilities as opposed to performance metrics established by the Commission in accordance with the policy goals

[17] NERP Report, PBR Regulatory Guidance: Implementation Suggestions for the NCUC From the North Carolina Energy Regulatory Process, at pp. 22-24 (2020), attached as Exhibit 4.

outlined in the legislation. The Commission can partially overcome this shortcoming by requiring any PBR application to address affordability, particularly for low-income customers, work in concert with the carbon reduction goals from Part I of HB951, and encourage increased energy efficiency and DER adoption, consistent with the public policy of the state as originally set forth in Senate Bill 3 in 2007 and reaffirmed in HB951. See N.C.G.S. § 62-2(a)(3a), (10).

The reliance on traditional cost-of-service regulation is explicitly reaffirmed in the section detailing what should apply to a multiyear rate plan (MYRP):

> The base rates for the first rate year of a MYRP shall be fixed in the manner prescribed under G.S. 62-133, including actual changes in costs, revenues, or the cost of the electric public utility's property used and useful, or to be used and useful within a reasonable time after the test period, plus costs associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during the first rate year.

N.C. Gen. Stat. § 62-133.16(c)(1)(a). This language enshrines capital investment as the main determinant of rates, making explicit the bias of the utility in favor of capital investments against non-capital solutions such as DERs and non-wires alternatives. For this reason, the Commission should guard against the built-in incentive towards utility capital investment and encourage enhanced reliance on energy efficiency and DERs as part of its criteria for evaluating PBR applications.

B. Implications of Mandated use of Minimum System Method

Another imbalance that the Commission should rectify in its PBR rules is the new statute's potential bias against the residential class by prescriptively mandating use of the disputed "minimum system" method for allocating distribution system costs between customer classes:

> …so long as the Commission allocates the electric public utility's total revenue requirement among customer classes based upon the cost causation principle, including the use of minimum system methodology by an electric public utility for the purpose of allocating distribution costs between customer classes…

N.C. Gen. Stat. § 62-133.16(b). No other element of the electric utility's cost of service methodology is prescribed by the new statute. This provision advantages the interests of large utility customers to the detriment of residential customers. As documented in the most recent general rate cases filed by the Duke Energy utilities,[18] the use of the minimum system methodology when allocating distribution costs inflates the costs attributable to the residential class. Because the minimum system method classifies a significant portion of distribution costs as "customer related," those costs are allocated based on number of customers as opposed to the actual demands on the system. Given the large number of residential customers, this choice has the effect of allocating more to the residential class than would be justified by using less subjective methodologies. The Commission should be sensitive to this "thumb on the scale" favoring non-residential customers when weighing other aspects of the Company's ultimate cost-allocation methodologies in any future general rate case or PBR application filed under HB951. As outlined

[18] See, e.g., direct testimony of Jonathan Wallach, Application by DEC for Adjustment of Rates, Docket No. E-7, Sub 1214, Official Transcript, Vol. XVII, Tr. pp. 511-22 (Sep. 4, 2020); testimony of Nicholas Phillips, Official Transcript, Vol. XXII, Tr. p. 152 (acknowledging that the use of the minimum system methodology results in larger allocation of costs to the residential class).

below, the Commission can and should take steps to mitigate the effect of this cost-shift to low-income customers in particular.

C. Revenue Decoupling

Another important feature of the new legislation is its requirement that a PBR application include revenue decoupling. Regulatory theory and practice have demonstrated that decoupling can dull the "throughput incentive" inherent in standard COS regulation, thereby removing a barrier to a utility's full embrace of energy efficiency measures and other distributed energy resources that reduce energy sales. However, and as discussed below, decoupling alone will not likely produce an increase in energy efficiency savings; it is a necessary but not sufficient condition. Other aspects of PBR are needed to actually incentivize energy efficiency activities.[19]

The ratemaking tools at the Commission's disposal following decoupling and PBR can free the utility and regulators from concerns over recovering so-called "fixed" costs[20] and allow for rate designs that shift more cost recovery to the volumetric rate and away from flat customer charges (such as the Basic Facilities Charge). Such rate design choices—on their own—can encourage the deployment of DERs and make energy efficiency investments more cost effective and attractive

[19] Revenue Regulation and Decoupling at 12.

[20] "A utility's expenses are often characterized as 'fixed' or 'variable'. However, for purposes of resource planning and other long-run views, all costs are variable and there is no such thing as a fixed cost. When designing a decoupling mechanism, it is more appropriate to differentiate between "production" and "non-production," since one purpose of the mechanism is to isolate the costs over which the utility actually has control in the short run (i.e., the period between rate cases)." Jim Lazar, Frederick Weston, and Wayne Shirley, *Revenue Regulation and Decoupling: A Guide to Theory and Application*, Regulatory Assistance Project at 4, N 4 (2011).

to customers.[21] Additional experimentation with rate design can provide other incentives for customers to conserve, providing lower rates for the initial block of kilowatt hour consumption for example,[22] or providing any earnings sharing to the first block of kilowatt hour usage (so that any decoupling adjustments would amplify incentives to customers for saving energy that inclining block rates provide).[23] For this reason, the included partial proposed rules would require any utility applying for a multiyear rate plan to also model and consider new rate designs that reduce or eliminate the fixed charge[24] or that incorporate inclining block rate elements.

D. Commission's Ability to Regulate in the Public Interest

As a general matter, the three components required to be included in a PBR application under HB951—decoupling, PIMs, and multiyear rate plans—were recommended to be adopted as a package by the NERP, albeit with stronger ratepayer protections and performance incentive structures than those that ended

[21] Revenue Regulation and Decoupling at 25 & 28 (noting that "with decoupling, the utility no longer experiences a net revenue decrease when sales decline, and will therefore be more willing to embrace rate designs that encourage customers to use less electricity. . . .[and] the best examples of this are the. . .rate designs used by California" IOUs, which do not have a fixed customer charge, although they do include a minimum bill).

[22] Revenue Regulation and Decoupling at 28 (noting that inverted block rates align incremental rates with incremental costs, properly collect appropriate costs from infrequent but expensive end uses, and "serve to encourage energy efficiency and energy management practices by consumers").

[23] Ralph Cavanaugh and John Howat, *Finding Common Ground Between Consumer and Environmental Advocates*, ElectricityPolicy.com at 6 (2012) (https://hepg.hks.harvard.edu/files/hepg/files/cavanagh-howat-5-2-12-final.pdf).

[24] NERP PBR Regulatory Guidance at p. 11 (Ex. 4) ("Decoupling is. . .better aligned with the goals of the [Clean Energy Plan] than increasing fixed charges as a means of removing the throughput incentive").

up in HB951.[25] It is now up to the Commission to ensure that these features work in a way to produce the correct incentives for North Carolina's electric utilities.

There are very few "public interest" provisions in the law itself, which deals mainly with protection of utility revenues under the label of "performance-based regulation." Nevertheless, the new law does contain a set of public interest factors that the Commission "may" consider when evaluating a utility's proposed PBR plan. Importantly, the Commission may consider whether the plan:

1) Encourages peak load reduction or efficient use of the system.
2) Encourages utility-scale renewable energy and storage.
3) Encourages DERs.
4) Reduces low-income energy burdens.
5) Encourages energy efficiency.
6) Encourages carbon reductions.
7) Encourages beneficial electrification, including electric vehicles.
8) Supports equity in contracting.
9) Promotes resilience and security of the electric grid.
10) Maintains adequate levels of reliability and customer service.
11) Promotes rate designs that yield peak load reduction or beneficial load-shaping.

N.C. Gen. Stat. § 62-133.16(d)(2).[26] Thus, the PBR law nods towards incentives and public interest outcomes, but does not address them directly in the new regulatory regime described in the statute. The Commission should take the opportunity in this rulemaking to balance the equities and include these important policy goals enumerated by the General Assembly in any PBR rules that it adopts.

The Commission has the authority to require utilities to incorporate features in their PBR applications that meaningfully address many of these public interest

[25] NERP PBR Fact Sheet at p. 2, supra note 10 (Ex. 3).

[26] See also NERP Regulatory Guidance at 5 (Ex. 4)

considerations listed in the new law. The statute defines “policy goals” broadly, and allows for the inclusion of “standards the Commission has established by order prior to and independent of a PBR application.” N.C. Gen. Stat. § 62-133.16(a)(8). This definition underscores the importance of the Commission adopting performance standards connected to appropriate policy goals in this rulemaking now, so they will be in place “prior to and independent of” any future PBR applications. Policy goals relating to reducing low-income energy burdens, encouraging use of DERs and energy efficiency, and reducing carbon pollution should be developed to bring about cost savings and operational efficiency. To create an opportunity for consumer benefits in the PBR plan, we endorse two additional PIMs; one targeting utility cost reductions and one that protects the existing system reliability. These consumer-facing PIMs directly serve the goals of “cost-savings, or reliability of electric service” found in Section § 62-133.16 (a)(8) of the new law and are rightfully a common feature of PBR plans.

The MYRP provisions mandate that any policy goals targeted by PIMs be “clearly defined, measurable with a defined performance metric, and solely or primarily within the electric public utility's control.” N.C. Gen. Stat. § 62-133.16(c)(3). For this reason, we recommend the establishment of (1) clearly defined goals that can be measured for those PIMs that can be defined now; (2) a supplemental rulemaking process to establish PIMs relating to low-income affordability following the ultimate recommendations of the Affordability Collaborative or other viable low-income proposals brought before the Commission; and (3) an integration of concrete goals for carbon reduction PIMs that will be connected to the carbon reduction plan established pursuant to Part I of HB 951.

As noted, NC Justice Center, NC Housing Coalition, Sierra Club, and SACE have specific interest in four of these eleven considerations from N.C.G.S. § 62-133.16(d)(2): "(iii) Encourages DERs; (iv) Reduces low-income energy burdens; (v) Encourages energy efficiency; [and] (vi) Encourages carbon reduction." Importantly, these priorities align with the PIMs recommendations of the NERP stakeholder group on reforming the utility regulatory framework in North Carolina.[27] None of these purposes will otherwise be linked to the rate making provisions in HB951, with the partial exception of decoupling. Decoupling will remove a barrier to energy efficiency, even if it does not affirmatively "encourage" energy efficiency. Later in these comments, we discuss how the Commission's rules can require utilities to address these four purposes, along with improvements in cost reductions and maintaining adequate reliability, in the attached partial proposed PBR rules.

In reviewing the list of eleven public interest considerations that the Commission may consider when reviewing a utility's proposed PBR plan, one can readily see that the regulatory language of the new law does not address these matters. In most cases, there is no direct provision in the new law addressing a public interest outcome. In one case, decoupling, the public interest purpose

[27] NERP PBR Fact Sheet at p. 2 (the NERP also recommended PIMs geared towards incentivizing customer service, electrification of transportation, peak demand reduction, and reliability/resilience), supra note 10 (Ex. 3).

(encouraging energy efficiency) is only weakly affected. If the Commission wants the items on the list in Section 62-133.16(d)(2) to be addressed in a utility's PBR filing, the Commission must affirmatively require it in this rule before utilities assemble their filings. The most direct way to do this is to require utilities to design and propose PIMs for inclusion in their PBR plans. The partial proposed rules included in this filing do just that. To illustrate how HB951, without affirmative attention from the Commission, misses the public-interest mark, consider the following table, examining whether and how HB951 addresses the eleven public interest considerations listed in N.C. Gen. Stat. § 62-133.16(d)(2).

Analysis of HB951 and Section 62-133.16(d)(2) Considerations

Section 62-133.16(d)(2) Considerations	Addressed in PBR language of HB951?	Comments
Encourages peak load reduction or efficient use of the system.	No provision or effect.	
Encourages utility-scale renewable energy and storage.	Only in non-PBR section of HB951.	Part 1, Section 1 of HB951, but not PBR section, will encourage utility scale renewable energy and storage.
Encourages DERs.	No provision; possible negative effect.	HB951 makes cost of utility rate base additions easier to recover, advantaging utility-owned resources compared to DER expenses. An example of capex bias in COS regulation.
Reduces low-income energy burdens.	No provision, possible negative effect.	The ratemaking provisions of HB951 mean that rates will likely be higher, not lower; Without intervention, HB951 will increase low-income energy burden.

Encourages energy efficiency.	Affected by decoupling provision.	Decoupling removes a barrier to energy efficiency – the throughput bias of COSR. However, the new law does not directly "encourage" energy efficiency.
Encourages carbon reductions.	Only in non-PBR section of HB951.	Section 1 of HB951 requires Commission to adopt
Encourages beneficial electrification, including electric vehicles.	No provision.	Permitting EV-related revenues to be excluded from decoupling calculation removes possible barrier to EV-related utility costs but does not directly "encourage" beneficial electrification.
Supports equity in contracting.	No provision or effect.	
Promotes resilience and security of the electric grid.	No provision or effect.	
Maintains adequate levels of reliability and customer service.	No provision.	Reliability is listed as a policy goal in definitions section, but there is no other provision.
Promotes rate designs that yield peak load reduction or beneficial load-shaping.	No provision or effect.	

As set forth in the attached partial proposed rules, the Commission can partially offset those shortcomings by giving full weight to the performance measures that are authorized in the law and exercising its inherent regulatory oversight role to require that utilities incorporate those listed policy goals into any future multiyear rateplan application.

IV. Low-Income Affordability

In the attached proposed rules, NC Justice Center, NC Housing Coalition, Sierra Club, and SACE recommend a requirement that any multiyear ratemaking application include the utilities' analysis of a performance incentive mechanism (PIM) relating to reducing low-income energy burdens.

In addition, given the unfinished work of the ongoing Affordability Stakeholder process, we respectfully ask the Commission to include in its PBR rules the requirement that no general rate case or multiyear application be submitted from Duke Energy Carolinas or Duke Energy Progress until the Commission has received the final report and recommendations of the Affordability Stakeholder working group. Pursuant to this Commission's Orders in the most recent general rate cases the two Duke Energy utilities, the final report and recommendations of the Affordability Stakeholder working group is due to the Commission by July 27, 2022 (one year following the inaugural meeting of the Collaborative).

Over two years ago, Duke Energy North Carolina President Stephen De May provided testimony about the importance of addressing low-income energy affordability in the context of the Companies' applications for rate increases.

> the Company requests that as part of its order in this case, the Commission direct the Company to host, and the Public Staff to participate in, a collaborative workshop with interested stakeholders to address the establishment of new low-income programs at [the Companies] and require that the Compan[ies] and/or the Public Staff file a final report with the Commission outlining the feedback and recommendations obtained in that workshop. The Company proposes to use the

> feedback and recommendations it receives from participants in such a workshop to form formal requests to the Commission for new, low-income programs.

Direct Testimony of Stephen De May, Docket No. E-2, Sub 1219 at 10 (Oct. 30, 2019); see also Docket No. E-7, Sub 1214 ().

As noted by Duke North Carolina President De May, the key outcome of this proposed process should be program recommendations to benefit low-income ratepayers for ultimate Commission consideration. NC Justice Center, NC Housing Coalition, SACE, and Natural Resource Defense Council submitted the testimony of John Howat of the National Consumer Law Center in those most recent rate cases, who provided evidence about best practices for low-income affordability programs, including various kinds of discount rates and arrearage management programs, to be complimented with increased investment in energy efficiency offerings for income-eligible households.[28]

Consistent with Duke President De May's recommendation and later stipulations and settlements between the Companies and Public Staff and between the Companies and NC Justice Center, NC Housing Coalition, NRDC, SACE, and NC Sustainable Energy Association (NCSEA), the Commission ordered the creation of an Affordability Collaborative to investigate a number of issues relating to energy affordability and to provide program recommendations. DEC Rate Case Order, Docket No. E-7, Sub 1214 at 173-79 (Mar. 31, 2021). The work of the

[28] Direct Testimony of John Howat, Application by DEC for Adjustment of Rates, Docket No. E-7, Sub 1214, Official Transcript, Vol. XVII, Tr. pp. 564-600 (Sep. 4, 2020);

Collaborative is underway. *See* DEC & Public Staff Low-Income Affordability Collaborative 180 Day Progress Report, Docket No. E-7, Sub 1214 (Sep. 27, 2021).

The Commission's Order requires consideration of the ultimate recommendations of the Affordability Collaborative before the Companies' next general rate case.

> The collaborative recommendations should include a mix of proposed programs that can be implemented in the near term and those that will require additional lead time to implement due to complexities. For example, the Commission anticipates/expects concrete proposals that (a) include both elements of rate design and programs that can be layered on top of existing or future rate plans, (b) **can be implemented by petition and proceedings prior to the next general rate case because the proposals do not include rate design changes**, (c) **will be proposed by DEC for consideration in its next general rate case**….

DEC Rate Case Order at 179 (emphasis supplied).

To remain in harmony with the Commission's Order establishing the Affordability Collaborative, the Commission should incorporate into its PBR rules a requirement that no multiyear rate plan be considered until the final report and recommendations of the Affordability Collaborative have been submitted to the Commission and the Commission has a chance to evaluate those recommendations and proposals. Otherwise, the Companies will not be in a position to propose affordable rate designs or other concrete program recommendations that come out of the Collaborative as part of any MYRP application or general rate case.

Likewise, while HB 951 was still under consideration in the General Assembly, Duke Vice President for Government Relations W. Kevin McLaughlin, Jr., wrote to a representative in the Governor's office regarding the importance of this low-income affordability collaborative to the Companies.[29] He wrote that:

> Duke Energy is committed to working with these stakeholders to develop recommendations for new programs, rate schedules, energy efficiency measures, potential funding mechanisms and other ways to assist low-income customers. Duke Energy is also committed to implementing those recommendations that the Commission deems beneficial to low-income customers

To consider a new general rate case or multiyear rate plan before the Affordability Collaborative has finished its work would invalidate the public commitments made by Duke Energy. The Collaborative should be allowed to make its recommendations and the companies and Commission should have the chance to incorporate those recommendations into any future rate case applications and program proposals.

V. Carbon Plan

To ensure that any capital expenditures contemplated by the Companies in association with a multiyear rate plan application are not at cross-purposes with carbon reduction targets mandated by HB951, it would be reasonable and prudent for the Commission to require completion of the carbon plan under Part I of the HB951 before moving forward with consideration of such a MYRP.[30] Any MYRP

[29] Letter from W. Kevin McLaughlin, Jr. to Dionne Delli-Gatti, attached as Exhibit 5.

[30] NERP Regulatory Guidance at pp. 15-16 (Ex. 4).

must include “costs associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during the first rate year.” N.C. Gen. Stat. § 62-133.16(c)(1)(a). It will be imperative that capital investments that are incorporated into a MYRP application be in harmony with—and not at cross-purposes with—the upcoming carbon plan.

VI. Partial Proposed Draft Rules and Need for Supplemental Rulemaking Process

In part because of extremely short timeframe for preparation of proposed rules, we submit 1) an annotated overview of the necessary rules and 2) details of two rules: Decoupling and PIMs. Due to the technical details required and the need for information about the utilities' accounting and administrative processes, we recommend that the Commission delegate the responsibility for drafting some of the initial rules to the utilities, with opportunities for comment and proposed revisions from intervenors, in line with directions provided in this rulemaking. In addition, NC Justice Center, NC Housing Coalition, Sierra Club, and SACE request that the Commission commit to supplemental rulemaking processes that will allow the Commission to incorporate information gleaned from the Technical Conference regarding projected transmission and distribution expenditures, the Carbon Reduction Plan, and the Affordability Collaborative into further PBR rule development.

VII. Outline of Partial Proposed PBR Rules

1) Basis and Purpose

2) Definitions

a) "Earnings sharing mechanism" means an annual rate-making mechanism that shares surplus earnings between the electric public utility and customers over the period of time covered by a multiyear rate plan (MYRP).

b) "Performance-based regulation" or PBR means an alternative rate-making approach that includes decoupling, one or more performance incentive mechanisms, and a multiyear rate plan, including earnings sharing mechanism, or such other alternative regulatory mechanisms as may be proposed by an electric public utility.

c) “First Year Base Revenues” means total allowed revenues “fixed in the manner prescribed under G.S. 62-133, including actual changes in costs, revenues, or the cost of the electric public utility's property used and useful, or to be used and useful within a reasonable time after the test period.”

d) “First Year Incremental Revenues” means the additional costs “associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during the first-rate year.”

e) “Second Year PBR Revenues” means the First Year Base Revenues plus additional costs “associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during” the second-rate year.

f) Third Year PBR Revenues” means the First Year Base Revenues plus additional costs “associated with a known and measurable set of capital investments, net of operating benefits, associated with a set of discrete and identifiable capital spending projects to be placed in service during” the third-rate year.

Note: Several additional definitions may be needed as PBR rules are more fully developed. They must adhere to the definitions contained in §62-133.16(a). These rules may also incorporate the legislative definitions by reference.

Filing requirements for utilities:

i) *Initial PBR application*

(1) Proposed first year revenue requirement from the general rate case in which the PBR application is filed, with and without the First Year Incremental Revenues.

(2) Current known and measurable capital investments and associated net changes in allowed revenues projected for the second-rate year.

(3) Current capital additions and associated net changes in allowed revenues projected for the third-rate year.

(4) A decoupling tariff consistent with these rules.

(5) The particular PIMs required by the Commission (Required PIMs), as set forth below, with operational details needed for implementation.

(6) Any PIMs proposed by the utility in addition to the Required PIMs (Additional PIMs), if any, with operational details needed for implementation and Commission consideration.

(7) A tariff establishing a revenue sharing mechanism consistent with HB951.

(8) For any known and measurable capital investments included in incremental revenues for the First, Second, or Third year, the utility shall include an analysis of how those capital investments support the carbon reduction plan that will be adopted pursuant to Part I of Session Law 2021-165

ii) *Subsequent filing requirements*

(1) Proposed Second Year PBR Revenues at the end of the First-Rate Year.

(2) Proposed Third Year PBR Revenues at the end of the Second-Rate Year.

(3) Application for approval of decoupling adjustment for Rate Years 2 and 3.

(4) Filing of a tariff rider including:

(a) Adjustment for decoupling
(b) Adjustment for net PIM rewards and penalties
(c) Adjustment for revenue sharing
(d) Adjustment to true-up prior year projected capital expense revenue requirement to the lesser of the projected or actual investment-related expense.

Note: These filing requirements do not replace or lessen any existing filing requirements required by the Commission.

3) Decoupling adjustment. (*See attached draft rule*)

4) PIMs

i) *Commission-required Performance Incentive Mechanisms (see attached draft rule)*

(a) Reduction in non-fuel cost per kwh delivered. (reward and/or penalty)

(b) Maintenance of adequate reliability as measured by SAIDI and SAIFI. (penalty only)

(c) Encourage deployment of Distributed Energy Resources ("DERs"). (reward only)

(d) Accelerated achievement of the carbon reduction targets in the Commission's carbon plan. The PIM would reward the utility for exceeding the required trajectory or milestones and penalize the utility for failure to meet the trajectory or milestones. (reward and/or penalty)

(e) Improvements in EE program deployment. (reward only)

(f) Enhanced low-Income affordability and reduction in low-income energy burdens. (reward and/or penalty)

ii) *Additional PIMs proposed by the utility that are in addition to the Commission-required PIMs.*

5) Earnings Sharing Mechanism

i) *Filing requirements.*
ii) *True-up of additional investment projected for the PBR rate year.*
iii) *Removal of PIM and other incentive revenues.*

iv) ***Treatment of decoupling adjustment.***

6) Riders

- **i)** Revenue adjustment if ROE on adjusted revenues exceeds authorized return plus 50 basis points.
- **ii)** Net incentive payments and penalties.
- **iii)** Decoupling adjustment.
- **iv)** True-up of prior year projected capital expense revenue requirement to the lesser of the projected or actual investment-related expense.

Note: Due to tight timeframes, it may be necessary for elements of the single rider to be updated at different times of the year.

7) Calendar for filings (assumes rate year begins in January). See attached illustrative calendar.

Illustrative Calendar for PBR Actions (assuming calendar-year PBR plan)

Year Prior to PBR		
February 1	Utility files rate case including optional PBR proposal.	
December 1	Commission enters order approving new revenue levels and approving, modifying, or denying PBR proposal.	HB951 sets the suspension period at a maximum 300 days
PBR Rate Year 1		
January 1	New rates are effective under PBR	
April 1	Commission files required report on PBR implementation.	
July 1	Utility identifies capital additions for PBR Rate Year 2; calculates associated revenue requirement for PBR Year 2.	This allows 135 days for examination of PBR Rate Year 2 proposed rates
November 15	Commission approves PBR Rate Year 2 rates.	
PBR Rate Year 2		
January 1	New rates are effective for PBR Rate Year 2.	
February 1	Utility files calculations for PBR Year 1 decoupling adjustment; PIM revenue/penalty calculation; true-up of prior year revenues to actual capex; earnings sharing results.	HB951 allows only 60 days for Commission review; filing would be 30 days after close of year.
March 1	Commission approves revised rider.	Allow 30 days for examination.
April 1	Adjusted rider becomes effective. Commission files required report on PBR implementation.	
July 1	Utility identifies capital additions for PBR Rate Year 3; calculates associated revenue requirement for PBR Year 3.	This allows 135 days for examination of PBR Rate Year 2 proposed rates
November 15	Commission approves PBR Rate Year 3 rates.	
PBR Rate Year 3		
January 1	New rates are effective for PBR Rate Year 3.	
February 1	Utility files calculations for PBR Rate Year 2 decoupling adjustment; PIM revenue/penalty calculation; true-up of prior year revenues to actual capex; earnings sharing results.	HB951 allows only 60 days for Commission review; utility filing would be 30 days after close of year.
March 1	Commission approves revised rider.	Allow 30 days for examination.
April 1	Adjusted rider becomes effective. Commission files required report on PBR implementation.	

Rule XX: Performance Incentive Mechanisms (PIMs)

1. HB951 authorizes the Commission to approve Performance Incentive Mechanisms (PIMs) as part of a three-year multi-year rate plan authorized under the law. If PIMs are subject to careful design and scrutiny, the Commission finds that one or more PIMs will be important elements in a PBR regime, bringing necessary balance and effectiveness to any incentive plan. Well-designed PIMs will increase the ability of this Commission and the state's utilities to serve the policy goals set forth in the statute.

2. Section 62-133.16(d)(2) contains a list of policy goals that the Commission may consider when determining whether to approve a utility's PBR proposal. The statute allows the Commission to consider whether a PBR proposal

a. Encourages peak load reduction or efficient use of the system.
b. Encourages utility-scale renewable energy and storage.
c. Encourages DERs.
d. Reduces low-income energy burdens.
e. Encourages energy efficiency.
f. Encourages carbon reductions.
g. Encourages beneficial electrification, including electric vehicles.
h. Supports equity in contracting.
i. Promotes resilience and security of the electric grid.
j. Maintains adequate levels of reliability and customer service.
k. Promotes rate designs that yield peak load reduction or beneficial load-shaping.

The extent to which a utility's proposed PBR plan is designed to further the outcomes listed in Section 62-133.16(d)(2) will be a central consideration in the Commission's decision to approve, modify, or reject the proposed PBR plan.

3. The Commission concludes that, for a PBR plan to achieve the outcomes listed in Section 62-133.16(d)(2), an approved plan must include targeted Required PIMs. In its PBR application, a utility shall propose, at a minimum, the six Required PIMs listed below for Commission consideration in the general rate case in which a PBR proposal will be examined. In addition, the utility may submit Additional PIMs to achieve policy goals for Commission consideration. The utility shall include the six specific Required PIMs set forth in Paragraph 4 for Commission consideration, regardless of whether the utility supports the adoption of these PIMs.

4. In any application for approval of a PBR plan, the utility shall include the following six Required PIMs, in addition to other PIMs proposed by the utility, if any:

a. **Reduction in Non-fuel cost per MWh delivered.** This PIM measures the extent of changes in the cost per MWh by the utility measured by the change in non-fuel costs per delivered MWh. The PIM should define both rewards and penalties, may be asymmetric with respect to rewards and penalties and may contain a “dead band” within which no PIM adjustment is made.

b. **Maintenance of adequate reliability as measured by SAIDI and SAIFI.** This PIM measures whether the utility is maintaining adequate reliability as measured by changes in SAIDI and SAIFI. The PIM should specify only penalties and may contain a “dead band” within which no adjustment is made.

c. **Encourage deployment of DERs.** This PIM measures the extent to which the utility encourages the deployment of cost-effective DERs. Key indicators in this PIM include (1) three-year rolling average of net metered projects connected (MW and number of projects); (2) total MW/MWh customer-sited storage enrolled in utility management programs; (3) number of customers (and MW) participating in utility programs to promote customer-owned or customer-leased DERs; and (4) utility changes to rate structures that encourage deployment of cost-effective DERs. Commission may also consider other metrics, such as number of customers (and MW) participating in grid services programs (including smart thermostats, control of electric water heaters, and storage) and improvements to interconnection of DERs. The PIM should specify only rewards.

d. **Carbon emissions reduction.** This PIM measures the extent to which the utility meets the carbon-reduction trajectory or milestones approved by the Commission pursuant to Part 1, Section 1 of HB951, to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO2) from 2005 levels by the year 2030. The PIM would reward the utility for early reductions that exceed the agreed trajectory or milestones and penalize the utility for failure to meet the approved trajectory or milestones. The PIM may include a “dead band,” which may be asymmetric, within which no rewards or penalties are assessed.

e. **Energy Efficiency.** This PIM measures the extent to which the utility exceeds (1) the savings target of 1.0% of prior year’s retail system sales established as the threshold for receipt of an additional incentive in the current DSM/EE Mechanism (Docket Nos. E-2, Sub 931 and E-7, Sub 1032), providing an opportunity to earn an additional incentive for achieving an increased increment of savings beyond 1.0 % of the prior year’s retail system sales for each of the three years of a MYRP (for example, in year one, a threshold of 1.2% of prior year’s sales would be required to earn the PIM; year two a threshold of 1.4%; and year three, a threshold of 1.6%); ; (2) expands the reach of EE measures that reach and benefit low-income households (to be determined for each utility); and (3) adoption of changes to rate structures that succeed in increasing adoption of cost-effective energy efficiency savings. The PIM should specify only rewards.

f. **Low-Income programs, policies and rate designs.** This PIM will measure the utility's success in implementing any approved recommendations from the Affordability Collaborative (ordered in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219) that reduce low-income energy burdens. In order to measure success in achieving the goals of this PIM, the utilities will be required to publicly report monthly data on residential disconnections for nonpayment, arrearages, and late fees by nine-digit zip code. Additional measures of success can include improvements in deployment of bill-saving Energy Efficiency programs for low-income customers (with attention to not double counting any such PIM adopted relating to energy efficiency); reduction in utility shut-offs for non-payment; and percentage of eligible customers who are enrolled in Commission-approved low-income discount rate and arrearage management plans to the extent that such measures are recommended by the Affordability Collaborative. The PIM should define both rewards and penalties, may be asymmetric with respect to rewards and penalties and may contain a "dead band" within which no PIM adjustment is made.

5. For each of the six PIMs listed in Paragraph 4, and for any additional or alternative PIMs proposed by the utility, the utility's PBR application shall include:

a. A description of the PIM.
b. The policy goals addressed by PIM.
c. The target against which performance is measured.
d. The metrics used to measure performance.
e. The source of the data needed to evaluate performance for the PIM.
f. The extent to which performance under the PIM is within the utility's control.
g. A system of rewards and/or penalties associated with performance.
h. The maximum recommended reward or penalty that may be assessed under each PIM and the total of such potential rewards or potential penalties across all proposed PIMs.
i. Whether the utility supports adoption of the PIM and, if not, the design changes that would allow the utility to support the PIM.

6. Tariffs and Reporting

a. Filing of tariff sheets describing adopted PIMs

b. On February 1 of each year, the utility will file:
    i. a report with its calculation of performance under the PIMs for the prior year.
    ii. The calculation of reward or penalty associated with each PIM.

Rule YYY -- Decoupling

1. Section 62-133.16(c) of HB951 requires an electric utility to include in its PBR application a rate making mechanism that breaks the "link between an electric public utility's revenue and the level of consumption of electricity on a per customer basis" in any PBR plan. Such mechanisms are known as "decoupling" mechanisms.

2. Any PBR application filed by an electric utility under Section 62-133.16 shall contain a decoupling mechanism in the form of a proposed tariff. In addition to any other information included in the decoupling tariff, the utility shall provide:

a. A statement of the purpose of the decoupling provision, including how the proposed decoupling mechanism complies with HB951, and whether and how the proposed mechanism will further the goal of increased energy efficiency.

b. A statement that explains how to measure the success of the decoupling tariff.

c. A statement of the form of decoupling proposed and the purpose behind such choice. This should provide a detailed definition of what types of sales changes are included in the mechanism, i.e., weather-related sales changes, energy efficiency related sales changes, distributed energy-related sales changes, etc., and the reason for such inclusion.

d. A detailed explanation of how the proposed decoupling mechanism will or will not affect the company's cost of capital.

e. Identification of which rate classes will be affected by decoupling adjustments and the rationale for the including or excluding any rate classes.

f. A precise statement of how the decoupling mechanism will operate and whether the program will be transparent and easy to follow from a customer perspective.

g. How well the surcharges or refunds created by the proposed decoupling mechanism will correlate with the actual usage of each customer during the rate year.

h. The utility's plans for customer education to explain the decoupling adjustment.

i. The following Implementation details:

i. Which utility costs are subject to the decoupling adjustment? Fixed costs? Variable costs?
ii. Which data or data calculations from the most recent rate case are needed to calculate the decoupling adjustment?
iii. How rate adjustments will be calculated.
iv. When rate adjustments will be made.
v. How the "annual revenue requirement per residential customer and an appropriate distribution of said revenue requirement per customer in each month of the year" will be calculated.
vi. How the number of customers per month will be calculated.
vii. Whether a rate cap or collar is proposed to mitigate the risk of rate shock and the justification for not so providing if a proposal lacks such provision.
viii. What portion of the customer's bill will be impacted by the decoupling adjustment?
ix. How will the decoupling rate adjustment be displayed on the customer's bill?
x. How the decoupling mechanism will work in concert with other financial incentives for energy efficiency activities, e.g., lost revenue adjustments. For the residential class, the lost revenue adjustment mechanism associated with the existing DSM/EE mechanism will no longer be needed and will need to be removed by the Commission.
xi. Whether and how the design of the decoupling mechanism will ensure there is no double recovery of revenues.
xii. How will the rider be designed that collects or refunds the annual decoupling adjustment?
xiii. How will the decoupling rider be "trued-up" to achieve targeted surcharges or refunds?

3. As part of its decoupling filling, the utility shall:

a. Model an alternative new default residential rate design for Commission consideration that substantially reduces or eliminates the fixed, customer charge and shifts recovery of those charges to the volumetric, per kWh rate and model the effect of those alternative rate designs on:

i. increasing participation in energy efficiency;
ii. increasing deployment of DERs; and
iii. bills for customers at different usage levels

b. Model inclining block rate design for the volumetric rate for residential customers for Commission consideration.

c. Model the following methods of distributing the decoupling credit or surcharge for Commission consideration:

i. The rate impact on customers at various usage levels of an allocation based on total energy use in a month for each customer; and
ii. The rate impact on customers of various usage levels of an allocation as follows:

1. A decoupling credit will be allocated on the first 500 kWh per month for each customer; and
2. A decoupling surcharge will be allocated on all usage in excess of 1,500 kWh per month for each customer.

Respectfully submitted this the 9th day of November, 2021.

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CERTIFICATE OF SERVICE

I certify that a copy of the foregoing Comments on behalf of North Carolina Justice Center, North Carolina Housing Coalition, Sierra Club, and Southern Alliance for Clean Energy as filed today in Docket No. E-100, Sub 178 has been served on all parties of record by electronic mail or by deposit in the U.S. Mail, first-class, postage prepaid.

This 9th day of November, 2021.

/s/ David L. Neal

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Employment History

2011-present Principal, Public Policy Consulting

Following my four-year term on the Colorado Public Utilities Commission, I resumed my consulting practice in energy policy and regulation. My focus is on climate, clean tech, regulatory reform, utility business models, integrated resource planning and smart grid.

Current and recent clients include Millennium Challenge Corporation, National Renewable Energy Laboratory, Nikola Power, Southern Environmental Law Center, Vote Solar, Hewlett Foundation, the U.S. Department of Energy, Northeast Clean Energy Council, Climate Policy Initiative, Steffes Corporation, Posigen, Sunshare LLC, Vivint Solar, Tendril Networks, Dow Solar, Lawrence Berkeley National Laboratory, Ceres, the Energy Regulatory Commission of Mexico, Environmental Defense Fund, Earthjustice, Blue Planet Foundation, the Future of Privacy Forum, American Efficient, and Conservation Colorado, among others.

International Engagements

In recent years, I have had assignments in energy policy and regulation in several foreign countries, including Jordan, Liberia, Malawi, Mexico, Nepal, Sierra Leone, and Tanzania. The activities include developing policy and regulatory roadmaps (Mexico, Nepal), reviewing and drafting legislation (Nepal, Tanzania), advising on electric market structure (Nepal, Malawi) hosting a technical conference (Mexico), designing regulatory agencies (Malawi, Sierra Leone, Nepal, Mexico), advising on natural gas regulation (Tanzania) and developing Smart Grid policy (Mexico).

2013 Nominee, Federal Energy Regulatory Commission

I was nominated by President Obama on June 27, 2013 to serve on the Federal Energy Regulatory Commission and, upon confirmation, to be designated as Chairman. My nomination was vigorously opposed by the coal industry and certain conservative political groups. Following a confirmation hearing, it appeared unlikely that my nomination would be reported favorably by the Senate Energy and Natural Resources Committee. I therefore asked that my name be withdrawn from further consideration.

2011-2013 Senior Policy Advisor, Center for the New Energy Economy

The Center for the New Energy Economy (CNEE) at Colorado State University is headed by former Colorado Governor Bill Ritter, Jr. The Center provides policy makers, governors, planners and other decision makers with a road map to accelerate the nationwide development of a New Energy Economy.

2007-2011 Chairman, Colorado Public Utilities Commission

I was appointed by Governor Bill Ritter, Jr. in January 2007. As Chairman, I helped implement the Governor's and Legislature's vision of Colorado's New Energy Economy, implementing the state's 30% Renewable Energy Portfolio Standard, fulfilling the Commission's role in the Governor's Climate Action Plan, streamlining telecommunications regulation, promoting broadband telecommunications investment and improving the operation of the Commission.

Here are some major accomplishments during my term on the Commission:

- **Implementing the Clean Air-Clean Jobs Act (2010).** Following passage of this new law in 2010, the Commission worked under a very compressed time schedule to examine proposals by XcelEnergy and Black Hills Energy to reduce pollutants from their coal fired generation plants. The contentious Xcel proceeding involves thirty-four legal parties, testimony from sixty-one witnesses and the consideration of more than a dozen contending compliance plans. The case required the close cooperation between the Commission and the Colorado Department of Public Health and Environment, the first such collaboration.

- **Implementing dozens of new energy, transportation and telecommunications laws.** In each legislative session during the term of Governor Ritter, the general assembly passed numerous sweeping utility-related laws. Many of these new laws required the Commission to adopt rules, compile reports, or conduct hearings. Rarely in Colorado history has there been this much activity required of the Commission.

- **Modifying and approving the electric resource plan of XcelEnergy (2009)**. After extensive hearings, the Commission approved a plan that includes large amounts of new wind capacity, the early closure of two coal power plants to reduce carbon and other emissions, the acquisition of 200-600 megawatts of solar thermal capacity, and substantial amounts of new energy efficiency savings. The target portfolio would reduce CO_2 emissions per megawatt-hour by 22% from current levels over eight years. The Commission decision required competitive acquisition for new resources.

- **Adopting new, aggressive energy efficiency requirement**s **(2008)** for Colorado gas and electric utilities. The Commission's requirements for electric utilities go well beyond the statutory minimum levels enacted in 2007. The Commission's policies also provided for rapid cost recovery of energy efficiency spending and bonus incentives for superior performance for the utilities.

- **Rewriting the Commission's electric resource planning rules (2007)** to require full consideration of future costs for carbon emissions, new clean energy resources and environmental and economic externalities. Retained and refined the requirements for competitive acquisition of new resources.

- **Improving communications with stakeholders.** I successfully sought legislation to modify the Commission's enabling statute, allowing the use of a "permit-but-disclose" communications process like the one employed successfully by the Federal Communications Commission and the FERC. The result has been much greater exposure of the Commissioners and staff (outside the hearing process) to the thinking of consumers, utilities, environmental advocates, large customers, advocates for new technologies, etc.

- **Organizing meetings of Western state regulators on regional transmission issues**. We discussed coordination in our efforts to add transmission capacity, especially to renewable energy zones. In future meetings we will discuss a goal of eliminating "pancaked" transmission pricing in the intermountain west.

- **Conducting hearings in eight towns around the state** on a "road trip" to collect consumer opinions about energy rates, distributed generation, the future of the energy sectors, and support for moving toward a more environmentally-sensitive utility industry.

- **Reorganizing the PUC's staff** to create a Research and Emerging Issues section. As chairman, I worked to improve deployment of the agency's modest staff so that the Commissioners could stay apprised of new technology and policy alternatives and be able to investigate and implement new regulatory approaches.

- **Reaching out to consumers and interest groups.** I frequently speak at meetings of consumer organizations, environmental groups, business and professional associations, legal seminars, etc. The two-way-street communications improves my understanding and conveys to the public the immense challenges we face in energy policy with climate change.

1995-2006 President, Public Policy Consulting

Consultant, specializing in energy and telecommunications regulatory policy issues. Assignments include strategic counsel to clients and research and testimony before regulatory and legislative bodies. In addition, I produced several research reports about the impact on rates of adding significant amounts of wind and solar capacity to utility systems. These reports are listed below.

I had a wide range of clients, including: consumer advocate offices, rural electric utilities, senior citizen advocacy groups, environmental groups, industrial electric users, homebuilders, building managers, telecommunications resellers, incumbent local exchange companies, low-income advocacy organizations, and municipal utilities. I testified as an expert witness before regulatory commissions in twelve states.

1996-2003 President and Policy Director, Competition Policy Institute

Competition Policy Institute was an independent non-profit organization that advocated for state and federal policies to bring competition to energy and telecommunications markets in ways that benefit consumers. Duties included: determining the organization's policy position on a wide range of telecommunications and energy issues; conducted research, produced policy papers, presented testimony in regulatory and legislative forums, hosted educational symposia for state regulators and state legislators.

1984-1995 Director, Colorado Office of Consumer Counsel

Director of Colorado's first state-funded utility consumer advocate office. By statute, the OCC represents residential, small business and agricultural utility consumers before state and federal regulatory agencies. The office was a party to more than two hundred legal cases before the Colorado Public Utilities Commission, the Federal Communications Commission, the Federal Energy Regulatory Commission and the courts.

Managed a staff of eleven, including attorneys, economists, and rate analysts who conduct economic, financial and engineering research in public utility matters. Testified as an expert witness on subjects of utility rates and regulation. Negotiated rate settlement agreements with utility companies. Regularly testified before the Colorado general assembly and spoke to professional business and consumer organizations on utility rate matters. Consulted with advisory board of consumer leaders from around the state.

Held leadership roles in National Association of State Utility Consumer Advocates. Member of high-level advisory boards to Federal Communications Commission (Network Reliability Council and North American Numbering Council) and Environmental Protection Agency (Acid Rain Advisory Council). Frequent witness before congressional committees and invited speaker before national industry and regulatory forums.

1977-1984 Consulting Utility Rate Analyst

Represented clients in public utility rate cases and testified as an expert witness in utility cases before regulatory commissions in Utah, Wyoming, Colorado and South Dakota. Clients included state and local governments, low income advocacy groups, irrigation farmers and consumer groups. Testimony spanned topics of telephone rate design, electric cost-of-service studies, avoided cost valuation of nuclear generation, electric rate design for irrigation customers and municipal water rate design.

1975-1984 Instructor in Mathematics

Taught mathematics at the University of Colorado, Denver and Boulder campuses. Nominated three times for outstanding part-time faculty member.

1971-1974 Manager, Blue Cross and Blue Shield

Managed major medical claims processing department. Responsibilities included budgets, hiring, training, managing supervisors, and coordinating with medical peer review committee.

Other Business Interests

1994-2011 **Managing Partner, Trail Ridge Winery**

Managing Partner and Secretary/Treasurer of Trail Ridge Winery. Trail Ridge Winery was located in Loveland, Colorado, and produced a variety of award-winning wines from Colorado-grown grapes.

Education

M.A. (Mathematics) 1977. University of Colorado. Course requirements met for Ph.D.

Graduate courses toward M.A. in Economics 1981-1984. University of Colorado. Twenty-seven hours including Economics of Regulated Industries, Natural Resource Economics, Econometrics.

B.A. with Honors (Philosophy) 1971. St. Louis University.

Professional Associations and Activities

Selected Current and Recent:

Board of Directors, Nikola Power

Board of Directors, GRID Alternatives Colorado

Board of Directors, GRID Alternatives (national)

Board of Directors, Western Resource Advocates (WRA)

Board of Directors, Southwest Energy Efficiency Project (SWEEP)

Board of Directors, Smart Electric Power Alliance (SEPA)

Advisor, Sunshare, LLC.

Brookings Institution, Non-resident Senior Fellow, 2013-2014

Harvard Electric Policy Group, John F. Kennedy School, Harvard University 1994-present

Advisory Council to the Board of the Electric Power Research Institute (EPRI) 2008-2011

Keystone Energy Board 2009-2012

Aspen Institute for Humanistic Studies, Communications and Society Programs 1986-present

Selected Past:

National Association of Regulatory Utility Commissioners
Member, Energy Resources and Environment Committee 2007-2011
Member, International Relations Committee 2007-2011
Chair, NARUC Task Force on Climate Policy 2010-2011
President, Western Conference of Public Service Commissioners, 2010-2011

Acid Rain Advisory Council to the Environmental Protection Agency, circa 1991
American Association for the Advancement of Science
American Vintners Association (*now* WineAmerica), Executive Committee, Membership Chair
Colorado Common Cause, Board Member
Colorado Energy Assistance Foundation, Board Member, Past President
Colorado Legislative Task Force on Information Policy, Gubernatorial Appointee 2000-2001
Colorado Public Interest Research Foundation, Board Member
Colorado Telecommunications Working Group, Gubernatorial Appointee
Colorado Wine Industry Development Board, Chairman
Council on Economic Regulation, Past Fellow
Denver Mayor's Council on Telecommunications Policy
Exchange Carriers Standards Association Network Reliability Steering Committee
Legislative Commission on Low-Income Energy Assistance, Past President
National Association of State Utility Consumer Advocates
President 1991-1992, Vice-President 1990, Treasurer 1987-1989
Chair, Telecommunications Committee 1992-1995
Network Reliability Council to the Federal Communications Commission
New Mexico State University Public Utilities Program, Faculty and Advisory Council
North American Numbering Council to Federal Communications Commission, Co-Chair
Outreach Committee, Western States Coordinating Council Regional Planning Committee
Total Compensation Advisory Council to the State of Colorado Department of Personnel
Who's Who in Denver Business

Selected Regulatory Testimony

From 1977 to 2021, Mr. Binz participated in more than 150 regulatory proceedings before the Federal Communications Commission, the Federal Energy Regulatory Commission, State and Federal District Courts, the 8th Circuit, 10th Circuit and D.C. Circuit Courts of Appeal, the U.S. Supreme Court and regulatory commissions in Arizona, California, Colorado, the District of Columbia, Georgia, Hawaii, Idaho, Indiana, Massachusetts, Maine, Michigan, Missouri, Montana, New York, North Dakota, South Carolina, South Dakota, Texas, Utah, Washington, and Wyoming. He has filed testimony in more than sixty proceedings before these bodies. His testimony and comments have addressed a wide variety of technical and policy issues in telecommunications, electricity, natural gas and water regulation.

Partial list of testimonies, comments, and presentations before regulatory commissions.

Before The Public Service Commission of Indiana. Cause No. 45546, Joint Petition Of Indiana Michigan Power Company (I&M) and AEP Generating Company (AEG) For Certain Determinations With Respect To The Commission's Jurisdiction Over the Return Of Ownership Of Rockport Unit 2. July 2021.

Before the Nevada Public Service Commission. Docket No. 19-06008. Rulemaking to amend, adopt, and/or repeal regulations in accordance with Senate Bill 300 (2019). January 2021.

Before the Public Service Commission of Michigan. Case Nos. U-20713 and U-20851. In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determination and/or approvals necessary for regulated electric providers to comply with Section 61 of 2016 PA 342. December 2020.

Before the Public Utilities Commission of Colorado. In the Matter of the Implementation of § 40-3-117, C.R.S. Regarding an Investigation into Performance- Based Ratemaking. March 2020.

Before the Public Service Commission of Montana. Electric Utility Rate Review NorthWestern Energy. Docket No. D2018.2.12. February 2019.

Before the Public Utility Commission of Hawaii. Instituting a Proceeding to Investigate Performance- Based Regulation. Docket No. 2018-0088. November 2018.

Before the Public Utilities Commission of South Carolina. Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Incorporated for Review and Approval of a Proposed Business Combination between SCANA Corporation and Dominion Energy, Incorporated, as May Be Required, and for a Prudency Determination Regarding the Abandonment of the V.C. Summer Units 2 & 3 Project and Associated Customer Benefits and Cost Recovery Plan. Docket Nos. 2017-370-E; 2017-305-E; 2017-207-E. November 2018.

Before the Public Utilities Commission of Rhode Island In Re: National Grid Application to Change Electric and Gas Distribution Revenue Requirements and Associated Rates. Docket No. 4780. April 2018.

Before the Public Utility Commission of Hawaii. In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. For Approval of General Rate Case and Revised Rate Schedules and Rules. Docket No. 2016-0328. Topic: Proposal for Incentive Based Regulation.

Before the Massachusetts Department of Public Utilities. Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an

Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00. April 2017. Topic: Proposal for Incentive Based Regulation.

Before the Public Utilities Commission of Hawaii. In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC., HAWAI'I ELECTRIC LIGHT COMPANY, INC., MAUI ELECTRIC COMPANY, LIMITED, and NEXTERA ENERGY, INC., For Approval of the Proposed Change of Control and Related Matters. "Testimony of Ronald J. Binz." January 2016. Topic: Conditions to be attached to merger approval.

Before the Public Service Commission of New York. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Case 14-M-0101. "Statement of Ronald J. Binz on Behalf of Earthjustice In Reply to Parties' Initial Comments on the Staff Straw Proposal" October 2014. Topic: Regulatory approach in the Commission's REV proposal.

Before the Public Service Utilities Commission of Hawaii. Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited. Docket No. 2013-0141. "Declaration of Ronald J. Binz." September 2014. Topic: Proposal for Incentive Regulation of HECO.

Before the Public Utilities Commission of California. Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements. Rulemaking 13-09-011. Comments and oral testimony of Ronald J. Binz before the Administrative Law Judge. August 2014.

Before the Public Service Commission of Wyoming. In the Matter of Rocky Mountain Power's Confidential Contract Filing Docket No. 20000-379-EK-10 of a Purchase Power Agreement between PacifiCorp and Pioneer Wind Park I. Binz Affidavit on behalf of Northern Laramie Range Alliance. Record No. 12618 (August 2011)

Before the West Virginia Public Service Commission. In the Matter of the Petition of Verizon West Virginia, Inc. To Cease Rate Regulation of Certain Workably Competitive Telecommunications Services. Case No. 06-0481-T-PacifiCorp (June 2006)

Before the Utah Public Service Commission. In the Matter of The Division's Annual Review and Evaluation of Electric Lifeline Program, HELP Rate Design Testimony. Docket No. 04-035-21 (September 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of YMCA of the Rockies. In re: YMCA of the Rockies, Complainant v. Xcel Energy (d/b/a Public Service Company of Colorado, Respondent. Rebuttal Testimony. Docket No. 05F-167G. (September 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of YMCA of the Rockies. In re: YMCA of the Rockies, Complainant v. Xcel Energy (d/b/a Public Service Company of Colorado, Respondent. Direct Testimony. Docket No. 05F-167G. (June 2005)

Before the Michigan Public Service Commission. Testimony on behalf of the Michigan Attorney General. In the Matter of SBC Michigan's Request for Classification of Business Local Exchange Service as Competitive Pursuant to Section 208 Of the Michigan Telecommunications Act. Case No. U-14323. (March 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of the Colorado Office of Consumer Counsel. In the Matter of the Combined Application of Qwest Corporation for Reclassification and Deregulation of Certain Part 2 Products and Services and Deregulation of Certain Part 3 Products and Services. Docket No. 04A-411T. (February 2005)

Before the Utah Public Service Commission. In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulation. Rate Design Testimony. Docket No. 04-035-42. (January 2005)

Before the Utah Public Service Commission. In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulation. Revenue Requirements Testimony. Docket No. 04-035-42. (December 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of the Building Owners and Managers Association of Metropolitan Denver (BOMA) in the Matter of The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado With Advice Letter No. 1411—Electric Docket No. 04S-164E (October 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Consumers in the Matter of The Application of Public Service Company of Colorado for Approval of its 2003 Least-Cost Resource Plan. Docket No. 04A-214E (filed: September 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Consumers in the Matter of the Application of Public Service Company of Colorado For an Order Authorizing It to Implement A Purchased Capacity Cost Adjustment Rider in Its PUC No. 7 – Electric Tariff. Docket No. 03A-436E. (filed: March 2004)

Before the Wyoming Public Service Commission. Testimony on behalf of Wyoming Industrial Energy Consumers (WIEC) and AARP In the Matter of the Application of PacifiCorp for Approval of a Power Cost Adjustment Mechanism. Docket No. 20000- ET-03-205 (filed: January 2004).

Before the Colorado Public Utilities Commission. Testimony on behalf of the Colorado Office of Consumer Counsel Regarding the Unbundling Obligations of Incumbent Local Exchange Carriers Pursuant to The Triennial Review Order – Initial Commission Review. Docket No. 03I-478T. (January 2004)

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of The Application of PacifiCorp For A Retail Electric Utility Rate Increase Of $41.8 Million Per Year Docket No. 20000-ER-03-198 (January 2004).

Before the Wyoming Public Service Commission. Public hearings testimony on behalf of AARP in the matter of an application by Kinder Morgan to modify the provider selection process in its Choice Gas Program. (December 2003).

Before the Public Service Commission of North Dakota. Testimony on behalf of AARP in the matter of In the Matter of the Notice of Montana-Dakota Utilities Co. for an Electric Rate Change. Case No. PU-399-03-296. (October 2003)

Before the Colorado Public Utilities Commission. Testimony in the matter of Public Service Company of Colorado's Advice Letter No. 598 – Natural Gas Extension Policy. Docket No. 02S-574G. (March 2003)

Before the Colorado Public Utilities Commission. Testimony in the remand hearings in the formal complaint case of the Homebuilders Association of Metropolitan Denver against Public Service Company. Docket 01F-071G. (January 2003)

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of an application by PacifiCorp to increase rates, recover excess net power costs, and recover purchase power costs related to the Hunter Unit 1 outage. Docket No. 20000-ER-02-184. Testimony Concerning A Proposed General Rate Increase and Surcharge for Previous Power Costs. (November 2002).

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of an application by PacifiCorp to increase rates, recover excess net power costs, and recover purchase power costs related to the Hunter Unit 1 outage. Docket No. 20000-ER-02-184. Testimony Concerning Hunter Unit 1 Issues. (November 2002).

Before the Colorado Public Utilities Commission. Comments on behalf of the Colorado Energy Assistance Foundation. Docket No. 02R-196G. In the Matter of the Proposed Repeal and Reenactment of the Rules Regulating Gas Utilities. (November 2002)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Assistance Foundation and Catholic Charities of the Archdiocese of Denver. Docket No. 02A-158E. In the Matter of the Application of Public Service Company of Colorado for an Order to Revise its Incentive Cost Adjustment. (April 2002)

Before the Idaho Public Utilities Commission. Testimony on behalf of Astaris, in the matter of Case No. IPC-E-01-43 concerning the buy-back rates under an electric load reduction program. (January 2002)

Before the Colorado Public Utilities Commission. Testimony in matter of the investigation of Advice Letters 579 and 581 of Xcel Energy on behalf of Homebuilders Association of Denver. Dockets 01S-365G and 01S-404G. (January 2002)

Before the Colorado Public Utilities Commission. Testimony in the formal complaint case of the Homebuilders Association of Metropolitan Denver against Public Service Company. Docket 01F-071G. (August 2001)

Before the Colorado Public Utilities Commission. Testimony in the matter of the investigation and suspension of Advice Letter No. 566 of Xcel Energy on behalf of the Homebuilders Association of Metropolitan Denver. Docket No. 00S-422G. (November 2000)

Before the American Arbitration Association. In the Matter of Univance Telecommunications, Inc. v. Venture Group Enterprises, Inc. Arbitration No. 77 Y 147 00099 00 (November 2000)

Testimony of Ronald Binz at FCC Public Forum on SBC/Ameritech merger (May 1999)

Docket No. 97-106-TC -- Testimony of Ron Binz before New Mexico State Corporation Commission on Investigation Concerning USWest's Compliance with Section 271(c) of the Telecommunications Act (July 1998)

Before the Colorado Public Utilities Commission. Testimony Concerning the Investigation of Telephone Numbering Policies. (March 1998)
Docket No. 6717-U Testimony before the Georgia Public Service Commission Concerning the Service Provider Selection Plan of Atlanta Gas Company. (January 1997)

Case 96-C-0603 and Case 96-C-0599--Testimony of Ronald J. Binz on behalf of CPI before the New York State Public Service Commission concerning the Bell Atlantic/NYNEX Merger (November 1996)

Docket No. 96-388 - Direct Testimony of Ronald J. Binz, CPI, On Behalf of the Office of the Public Advocate (October 1996) State of Maine, Public Utilities Commission Joint Petition of New England Telephone and Telegraph Company and NYNEX Corporation for Approval of the Proposed Merger of a Wholly-Owned Subsidiary of Bell Atlantic Corporation into NYNEX Corporation.

Application No. 96-04-038 - Direct Testimony of Ronald J. Binz, CPI, On Behalf of Intervener, Utility Consumers Action Network (September 1996) Before the Public Utilities Commission of the State of California In the Matter of the Joint Application of Pacific Telesis Group (Telesis) and
SBC Communications (SBC) for SBC to Control Pacific Bell (U 1001 C), Which Will Occur Indirectly as a Result of Telesis' Merger with a Wholly Owned Subsidiary of SBC, SBC Communications (NV) Inc.

Presentation to Federal-State Joint Board on Universal Service (April 12, 1996)

Testimony before the Texas Public Utility Commission on the Integrated Resource Planning Rule (March 1996)

Congressional Testimony

Mr. Binz has appeared sixteen times before U.S. House and Senate Committees. In addition, he has testified numerous times before state legislatures in several states. Here is a list of his U.S. Congressional testimony and statements:

United States Senate Energy and Natural Resources Committee, 2013. Statement in support of my nomination to the Federal Energy Regulatory Commission.

United States House of Representatives Commerce Committee, Energy Subcommittee, 2008. Testimony concerned a proposal to adopt a federal renewable energy standard.

United States House of Representatives Judiciary Committee, November 1999. Testimony concerning H.R. 2533, The Fairness in Telecommunications License Transfer Act of 1999.

United States Senate Judiciary Committee; Antitrust, Business Rights and Competition Subcommittee, April 1999. Testimony concerning S.467, The Antitrust Merger Review Act.

United States Senate Commerce Committee, Telecommunications Subcommittee, May 1998. Testimony in oversight hearings concerning the performance of the Common Carrier Bureau of the Federal Communications Commission.

United States Senate Judiciary Committee, Washington, D.C., September 1996. Presented testimony on behalf of the Competition Policy Institute on the competitive impact of proposed mergers of Regional Bell Operating Companies.

United States House of Representatives Subcommittee on Telecommunications and Finance of the Committee on Commerce, May 1995. Testimony presenting NASUCA’s position on H.R. 1555 by Representative Fields.

United States Senate Subcommittee on Antitrust, Washington, D.C., September 1994. Testimony presenting NASUCA's position on S. 1822 by Senator Hollings.

United States House of Representatives Subcommittee on Telecommunications and Finance of the House Energy and Commerce Committee, Washington, D.C., February 1994. Presented testimony on H.R. 3636.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., October 1992. Supplemental testimony presenting NASUCA's position on legislation concerning the Modified Final Judgment introduced by Representative Brooks.

United States House of Representatives Subcommittee on Telecommunications and Finance, Washington, D.C., October 1991. Testimony on RBOC entry into telecommunications manufacturing and information services.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., August 1991. Testimony presenting NASUCA's position on possible federal legislation concerning the Modified Final Judgment.

United States Senate Subcommittee on Energy Regulation and Conservation, Denver, Colorado, April 1991. Testimony presenting NASUCA's position on federal legislation concerning regulation of the natural gas industry, introduced by Senator Wirth.

United States Senate Communications Subcommittee, Washington, D.C., February 1991. Testimony on behalf of NASUCA concerning S.173, telecommunications legislation introduced by Senator Ernest Hollings.

United States Senate Communications Subcommittee, Washington, D.C., July 1990. Testimony on behalf of NASUCA concerning S.2800, telecommunications legislation introduced by Senator Conrad Burns.

United States House of Representatives Subcommittee on Telecommunications and Finance, July 1988. Testimony on the FCC Price Cap proposal.

Reports and Articles

Title	Publisher	Date
Considerations for the Governance of a Western Regional System Operator	Public Policy Consulting	March 2016
Practicing Risk Aware Electricity Regulation: 2014 Update	Ceres	November 2014
Priorities after FERC Overture	EnergyBiz Magazine	Jan-Feb 2014
Risk-Aware Planning and a New Model for the Utility-Regulator Relationship	ElectricityPolicy.com	July 2012
Practicing Risk Aware Electricity Regulation: What Every State Regulator Needs to Know	Ceres	April 2012
Conquering Consumer Resistance: Time to cross the bridge to time-of-use rates	EnergyBiz Magazine	March-April 2012
Cap and Innovate: An alternative approach to climate regulation.	Public Utilities Fortnightly	June 2010
Wind on the Public Service Company of Colorado System: Cost Comparison to Natural Gas	Interwest Energy Alliance (with Jane Pater)	August 2006
The Impact of the Renewable Energy Standard in Amendment 37 on Electric Rates in Colorado	Public Policy Consulting	September 2004
The Impact a Renewable Energy Portfolio Standard on Retail Electric Rates in Colorado	Public Policy Consulting	February 2004
Qwest, Consumers and Long-Distance Entry: A Discussion Paper	Public Policy Consulting	October 2001
Addressing Market Power: The next step in electric restructuring	Competition Policy Institute	June 1998
Navigating a Course to Competition: A consumer perspective on electric restructuring	Competition Policy Institute	August 1997

Ron Binz, Public Policy Consulting
Recent Experience relating to Performance Based Regulation

1. Before the Nevada Public Service Commission. Docket No. 19-06008. Rulemaking to amend, adopt, and/or repeal regulations in accordance with Senate Bill 300 (2019). January 2021. Workshops on Incentive Regulation of Nevada Electric Utilities.

2. Before the Public Utility Commission of Hawaii. Instituting a Proceeding to Investigate Performance- Based Regulation. Docket No. 2018-0088. Extended workshop and comment process to develop PBR design. November 2018 to July 2020.

3. Before the Public Utilities Commission of Colorado. In the Matter of the Implementation of § 40-3-117, C.R.S. Regarding an Investigation into Performance-Based Ratemaking. Workshops and written comments on Incentive Regulation for Colorado Electric Utilities. March 2020

4. Before the Public Utilities Commission of Rhode Island In Re: National Grid Application to Change Electric and Gas Distribution Revenue Requirements and Associated Rates. Docket No. 4780. April 2018.

5. Before the Public Utility Commission of Hawaii. In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. For Approval of General Rate Case and Revised Rate Schedules and Rules. Docket No. 2016-0328. Topic: Testimony in three dockets for Hawaiian Electric (HECO), Maui Electric (MECO), and Hawaii Electric Light (HELCO) concerning the design of fuel cost adjustments to reflect risk and incentive features. 2017-2019

6. Before the Massachusetts Department of Public Utilities. Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00. April 2017. Topic: Proposal for Incentive Based Regulation.

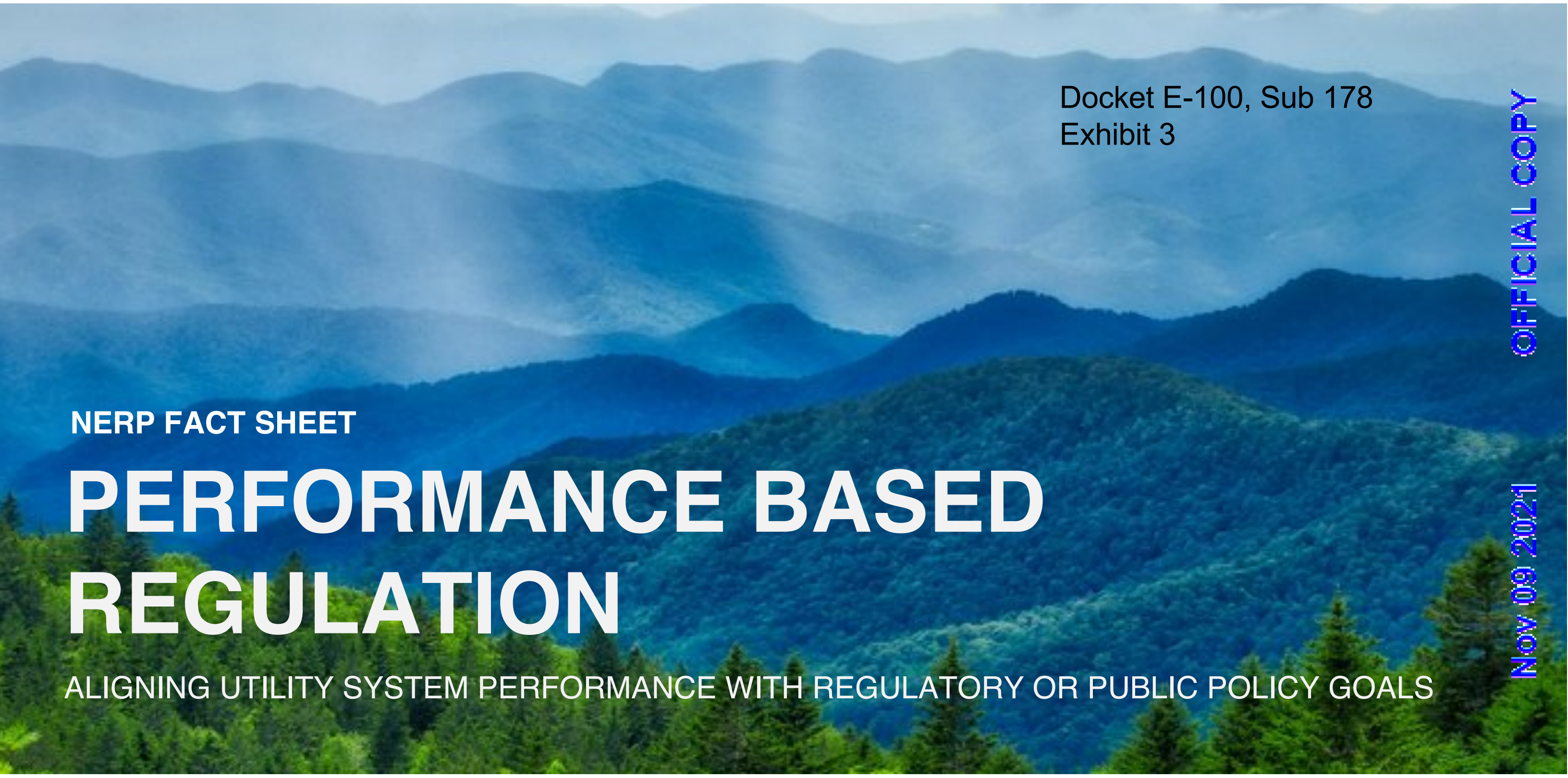
7. Before the State of New York Public Service Commission. Proceeding on the Motion of the Commission in Regard to Reforming the Energy Vision. Statement of Ronald J. Binz on Behalf of Earthjustice. 2014

8. Creator and co-chair of the ***Utilities 2020*** project. Foundation-funded exploration of changes needed in regulation to meet climate change and other new industry challenges. Featured participation of 10 utility CEOs, 8 state regulators, consumer leaders and environmental advocates in interviews and workshops. 2013.

9. Author of "*Risk-Aware Planning and a New Model for the Utility-Regulator Relationship. Energy Policy Magazine.* 2012

10. Principal author of “Practicing Risk Aware Electricity Regulation: What Every State Regulator Needs to Know.” April 2012

11. Presentations on performance-based regulation before regulators, legislators, and NGOs.



NERP FACT SHEET

PERFORMANCE BASED REGULATION

ALIGNING UTILITY SYSTEM PERFORMANCE WITH REGULATORY OR PUBLIC POLICY GOALS

The 2020 North Carolina Energy Regulatory Process prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

WHAT IS PERFORMANCE BASED REGULATION?

Performance based regulation (PBR) is a regulatory approach that more precisely aligns utilities' profit interests with customer and societal interests through regulatory mechanisms that incentivize utilities to improve operations and management of expenses, increase program effectiveness, and otherwise align system performance with identified regulatory or public policy goals.

WHAT IS THE OPPORTUNITY?

While North Carolina is a leader in clean energy, with the second highest installed solar capacity in the nation, more than 40% of in-state generation being provided by carbon free resources, and over 110,000 clean energy sector jobs,[1] the future success of the state's clean energy transition will require, among other things, substantial greenhouse gas emission reductions; increased electric energy conservation savings over and above current savings of 1%[2]; continued grid modernization investments in storm hardening, targeted undergrounding of transmission and distribution power lines, and advanced metering; and increased integration of innovative distributed energy solutions, including customer sited solar and energy storage. Indeed, both Duke Energy and Dominion Energy have established ambitious mid-century clean energy targets. Duke's own Queue Reform Proposal calls for more than "5,390 MW of additional proposed North Carolina-sited utility-scale solar projects."[3]

Furthermore, existing utility incentives under the current ratemaking system are not always aligned with achieving these outcomes. Under the current system, utilities make more money by increasing their electric sales, which dis-incentivizes increased energy conservation. In addition, grid modernization investments are often not in a utility's financial best interest, at least in the short to medium term, as considerable time may pass between when (1) a utility first incurs financing costs to fund grid modernization investments and (2) it can stand to potentially recover all of those costs in a rate case.[4] Furthermore, a utility typically earns no profits on distributed energy, with profits being earned instead from infrastructure the utility owns and uses to provide electric services, in particular generation assets. Therefore, utilities may be incentivized to prioritize investments in utility owned generation over

[1] *See* https://www.e2.org/wp-content/uploads/2019/07/E2-Clean-Jobs-North-Carolina-2019.pdf
[2] *See* https://nicholasinstitute.duke.edu/sites/default/files/publications/North-Carolina-Energy-Efficiency-Roadmap-Final.pdf
[3] *See* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=f83235af-6c15-4a08-ab04-7d03ef047383
[4] A rate case is a process through which a utility can adjust the rates it collects from customers by seeking approval from the North Carolina Utilities Commission.

investments that might, over the long term, reduce the amount of utility generation and result in cleaner energy.

If the Clean Smokestacks Act, Senate Bill 3, House Bill 589, and other landmark state clean energy legislation are any indication, further state legislative action will be crucial to the future of the state's clean energy transition. In particular, performance based regulation can help catalyze clean energy innovation.

WHAT IS BEING RECOMMENDED?

The North Carolina Energy Regulatory Process (NERP) has identified three mechanisms that should be adopted as a package:

1. Decoupling – a ratemaking mechanism that severs the link between utility sales and revenues by authorizing allowed revenues separate from utility sales and adjusting prices periodically to ensure actual revenues match allowed revenues.

2. Performance incentive mechanisms (PIMs) – a ratemaking mechanism that ties some portion of a utility's revenues or earnings to its performance on measurable customer, utility system, or public policy outcomes.

3. Multi-year rate plan (MYRP) with an earnings sharing mechanism – a ratemaking mechanism through which base rates and revenues are fixed for a multi-year term and a utility is barred from filing a rate case during that term (often referred to as a rate case moratorium). Rates or revenues are then periodically adjusted in non-rate case proceedings according to a predetermined formula or set of variables (e.g. inflation).

   An earnings sharing mechanism allocates to customers a portion of utility overearnings that exceed (or under-earnings that fall short of) the earnings approved under a multi-year rate plan.

HOW DOES PERFORMANCE BASED REGULATION WORK? HOW IS IT DIFFERENT FROM THE CURRENT SYSTEM?

For a multi-year rate plan, which NERP recommends should be combined with decoupling and PIMs, a utility would still be required to file an initial base rate case to adjust its authorized electric rates and submit cost of service studies. These studies would in turn serve as the basis through which the North Carolina Utilities Commission would determine (1) the total revenue required for the utility and (2) how the revenue would be allocated and collected from the utility customer classes. The proposed performance based regulations, specifically decoupling, PIMs, and the revenue adjustment mechanisms within a MYRP, would adjust, through increments or decrements, any base rates approved in the base rate case.

Decoupling

Once the revenue requirement is established, a decoupling mechanism would provide for periodic rate adjustments to ensure that the utility's actual revenues match its allowed revenues. Therefore, in contrast to the current system, where sales increases result in increased utility revenues, if a utility's sales increased under decoupling, rates would instead be adjusted downward to ensure parity between the utility's actual revenues and allowed revenues. If utility sales decreased, rates would be adjusted upwards to ensure the utility's actual revenues equaled its allowed revenues. As a result, changes in utility sales would have no impact on a utility's revenues, and a utility would no longer be dis-incentivized to pursue energy efficiency savings.

NERP recommends that the legislature authorize the Commission to adopt decoupling. Among other things, NERP suggests that the Commission limit the application of an approved decoupling mechanism to base rates and the residential, small and medium general service customer classes. Detailed suggestions for the Commission are contained in the NERP Guidance on Performance-Based Regulation.[5]

Performance Incentive Mechanisms

Performance incentive mechanisms would condition some portion of a utility's earnings on its performance on certain measurable consumer, utility system, or public policy outcomes. For example, if a utility were to meet identified distributed energy integration or energy efficiency performance targets, it could receive a fixed cash reward, a basis point adjustment to its return on equity, a percentage return on any expenses incurred achieving those targets, or a portion of any shared savings or net benefits created through its achievement of those targets. Conversely, depending on the design of the performance incentive mechanism, a utility might be penalized for failing to achieve those targets. As a result, a utility would have a direct incentive to pursue these outcomes.

This is a departure from the current system, where a large portion of utility earnings stems from the allowed rate of return on certain capital expenditures. Certain PIMs can help to mitigate this capital expenditure (or "capex") bias by providing the utility the opportunity to profit from meeting agreed-upon performance targets.

NERP recommends that the legislature authorize the Commission to adopt performance incentive mechanisms. Specifically, NERP recommends that the Commission consider PIMs that incentivize affordability, carbon reduction, customer service, distributed energy, electrification of transportation, energy efficiency, equity, peak demand reduction, reliability,

[5] The Guidance Document is available with all other NERP outputs on the website at the end of this fact sheet.

and resilience. Detailed suggestions for the Commission are contained in the Guidance Document.

Multi-Year Rate Plan and Earnings Sharing Mechanism

A multi-year rate plan usually begins with a rate case that determines a utility's initial revenue requirement and establishes how these allowed revenues should be adjusted each year over the course of the rate plan term, which is typically between three and five years. These adjustments can be based on cost forecasts, external indexes, or a combination of both. In contrast to the current system, where the underlying costs recovered in rates reflect prior costs incurred in some previous twelve-month period (referred to as the historic test year), costs and revenues for a multi-year rate plan are forward-looking.

Accordingly, the utility could prospectively identify grid modernization projects and ensure more timely cost recovery for these projects and other investments. In addition, the rate case moratorium could create significant cost containment pressure. A multi-year rate plan that capped a utility's revenues would also incentivize cost containment by providing the utility the opportunity to keep some or all of its cost savings. Given these cost containment incentives, some experts recommend that states adopt targeted PIMs to prevent potential cost cutting from impacting system reliability and customer service.

Subject to Commission pre-approval, an earnings sharing mechanism could specify a formula for sharing any utility cost savings or losses between customers and utility shareholders when utility earnings exceed or fall short of Commission set levels.

NERP recommends that the legislature authorize the Commission to adopt multi-year rate plans and earnings sharing mechanisms. Detailed suggestions for the Commission are contained in the Guidance Document.

HAS PERFORMANCE BASED REGULATION BEEN DONE BEFORE?

Other states

Several other states and international jurisdictions have pursued performance-based regulation. For example, New York is exploring performance based regulation through the Reforming the Energy Vision proceeding before the New York Public Service Commission. Through this proceeding, the Commission has adopted performance incentive mechanisms for distributed energy and other innovative non-wires solutions. In Minnesota, recent legislation, direction from the Minnesota Public Utilities Commission, and extensive stakeholder involvement have resulted in wide ranging performance-based regulation reforms, including a MYRP and decoupling. For more information on the Minnesota PBR development process and outcomes, see the MN PBR Case Study prepared by NERP.[6]

North Carolina

Natural gas decoupling, which is currently authorized under statute, was implemented in North Carolina in 2005. In addition, the North Carolina Utilities Commission has adopted performance incentive mechanisms pursuant to a separate statute to encourage more utility energy efficiency programs and savings.

This fact sheet represents the work of stakeholders as of 12/18/2020.

About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

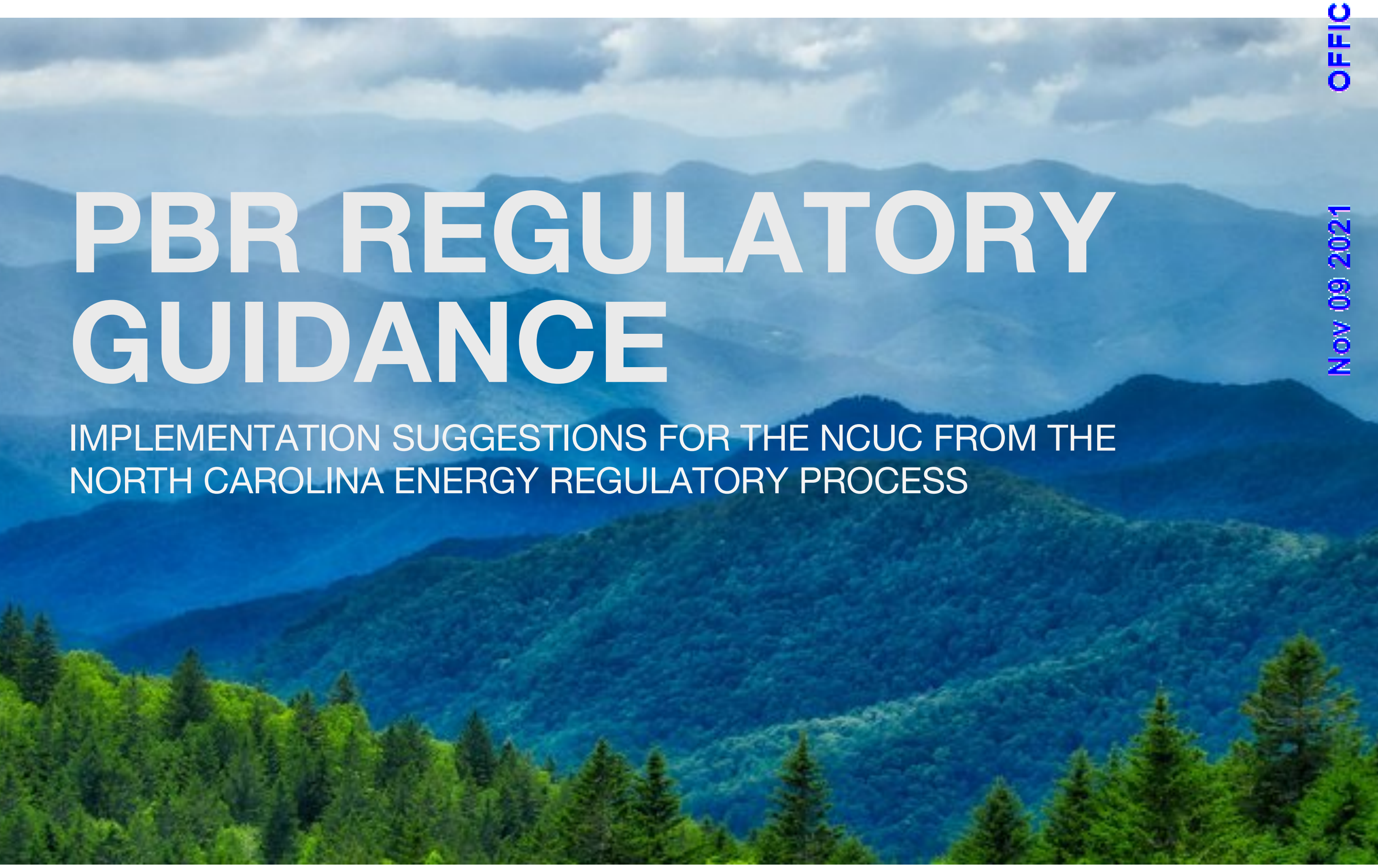
LEARN MORE

Contact NERP PBR Study Group Leads:
Sally Robertson, NC WARN, sally@ncwarn.org
Laura Bateman, Duke Energy, laura.bateman@duke-energy.com

Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

[6] See the Minnesota case study, available with all other NERP outputs on the website at the end of this fact sheet.

Docket E-100, Sub 178
Exhibit 4



PBR REGULATORY GUIDANCE

IMPLEMENTATION SUGGESTIONS FOR THE NCUC FROM THE NORTH CAROLINA ENERGY REGULATORY PROCESS

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ABOUT THE NORTH CAROLINA ENERGY REGULATORY PROCESS

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

ABOUT THIS DOCUMENT

This guidance document contains a detailed discussion of performance-based regulation mechanisms with a specific focus on revenue decoupling, multi-year rate plans, and performance incentive mechanisms. It includes recommendations for the NCUC to consider if and when it begins a process to implement performance-based regulation. The document represents the consensus work of the NERP process stakeholders as of the above date. However, individual NERP stakeholders do not necessarily endorse all of the ideas or recommendations herein.

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SUMMARY OF RECOMMENDATIONS

This document contains recommendations for implementation of performance-based regulation (PBR) developed by the North Carolina Energy Regulatory Process (NERP) participants. The primary intended audience is the NC Utilities Commission (NCUC), as it may be authorized by the General Assembly to develop regulations for PBR. The document contains detailed descriptions of each of the PBR mechanisms discussed in NERP: revenue decoupling, multi-year rate plans (MYRPs), and performance incentive mechanisms (PIMs). NERP participants met throughout 2020 and developed the following recommendations regarding the implementation of PBR.

PBR implementation

1. PBR should be designed to provide for just and reasonable rates and be consistent with the public interest, including the goals of the Clean Energy Plan.
2. PBR for NC should include all three of the mechanisms studied in NERP, as they can work well together to accomplish a broad set of outcomes and stakeholder objectives.
3. Effective PBR will require ongoing monitoring and possible course corrections.
4. A PBR process at the NCUC should consider the conclusions reached by NERP and make sure to receive comment from as broad a group of stakeholders as possible, including representatives from underserved communities with limited access to traditional docket proceedings.
5. The NCUC should, subject to guidance and timelines provided in legislation, begin as soon as possible a proceeding to develop rules for filing, and criteria for evaluating, a comprehensive PBR package including revenue decoupling, a multi-year rate plan, and performance incentive mechanisms or tracked metrics, as well as provisions for annual or more frequent decoupling and MYRP true-ups and adjustments of PIM metrics, targets, and incentive levels.

Revenue decoupling

1. Revenue decoupling should apply to residential and small and medium general service classes. Large general service and lighting do not necessarily need to be included. However, attention should be paid to how excluding any customer class would impact the design of a multi-year rate plan.
2. Revenue decoupling should include all utility functions (generation, transmission, and distribution).
3. Revenue decoupling should include base rates only, excluding riders that have separate true-up mechanisms.
4. Revenue decoupling should include EV charging sales, but a PIM should be adopted related to EV adoption and/or smart charging to incentivize vehicle electrification.
5. Revenue decoupling should utilize either the revenue-per-customer or attrition method for adjusting revenue between rate cases. Decoupling adjustments to the allowed revenue would be impacted by the MYRP design as well, so the interplay of these two mechanisms should be noted.
6. The amount of adjustment to customer rates under decoupling should be capped, and the design of refunds and surcharges should consider ways to encourage energy efficiency.
7. Rate adjustments should occur once a year.
8. The NCUC will need to consider the above issues, as well as ways to encourage utilities to pursue beneficial electrification when decoupled.

Multi-year rate plan

1. The mechanism for adjusting rates should be defined at the outset of a MYRP.
2. A maximum of three years should be the term of an initial MYRP.
3. A MYRP should not be used to recover costs for large, discrete investments, such as a conventional power plant. Investment programs that are made up of a series of smaller utility assets placed in service over time are well-suited for a MYRP.
4. A MYRP should be accompanied by a pre-set earnings sharing mechanism to share savings between customers and utility stockholders. The mechanism could include sharing tiers and a “deadband” of over- or underearning in which no adjustment is made.

5. The NERP team did not come to consensus on whether MYRP should cover base rates or be more narrowly constructed to cover only certain projected costs.
6. The NCUC should determine the general conditions under which a MYRP may be revised or revisited.

Performance incentive mechanisms

1. PIMs should adhere to a set of principles to help align stakeholders on shared objectives and guide PIM design.
2. At the outset, utilities should track as many metrics as are deemed useful and cost-effective. This document lays out recommended metrics.
3. The utility should 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.
4. The utility should establish a public dashboard for reporting performance on PIMs and tracked metrics.
5. The following outcomes should be targeted for PIM and/or tracked metric development:
    a. Peak demand reduction
    b. Integration of utility-scale renewable energy and storage
    c. Integration of distributed energy resources
    d. Low-income affordability
    e. Carbon emission reductions
    f. Electrification of transportation
    g. Equity in contracting
    h. Resilience
    i. Reliability
    j. Customer service
6. The NCUC will need to evaluate the appropriateness of any proposed performance incentive assigned to each potential tracked metric.

INTRODUCTION

Purpose and objectives

The purpose of this document is to communicate the findings of the NC Energy Regulatory Process (NERP) with regard to performance-based regulation (PBR) to the NC Utilities Commission (NCUC) as it may be authorized by the General Assembly to develop rules for PBR. It may also be of interest to the NC General Assembly and other parties who want more information on PBR or the NERP process than is provided in the companion fact sheet.[1]

Duke Energy's Climate Report[2] and Dominion Energy's Sustainability and Corporate Responsibility Report[3] set ambitious goals for reducing carbon emissions. The NC Clean Energy Plan[4] calls for the state's electric power sector to reduce greenhouse gas emissions 70% below 2005 levels by 2030 and attain carbon neutrality by 2050, transitioning to cleaner energy resources while growing the state's economy. As detailed below, however,

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[1] All NERP PBR companion documents can be found at the following location: https://deq.nc.gov/CEP-NERP

[2] *Achieving a Net Zero Carbon Future: Duke Energy 2020 Climate Report*, https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf?la=en.

[3] *Building a Cleaner Future for Our Customers and the World, 2019 Sustainability and Corporate Responsibility Report*, Dominion Energy, https://sustainability.dominionenergy.com/assets/pdf/Dominion-Energy_SCR-Full-Report-FY2019.pdf.

[4] *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System*, NC Dept. of Environmental Quality, Oct. 2019, https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.

the current cost of service (COS) ratemaking[5] system for the state's investor-owned utilities (IOUs) does not provide the proper utility incentives for timely and efficient accomplishment of these goals at reasonable cost.

NERP stakeholders have determined that better alignment of incentives would be created by transitioning the state to a comprehensive PBR framework.

This document communicates NERP's recommendations for designing a PBR system that would benefit North Carolina.

Improved Utility Regulations for North Carolina's Energy Transition

PBR offers a suite of reforms that, together, can resolve limitations of COS ratemaking while encouraging utilities to better serve state policy goals and customer interests. In North Carolina, this includes decarbonization of the power system, accelerated adoption of clean energy technologies including new customer service opportunities from distributed energy resources (DER), alleviating low-income energy burden, and reduction of costly administrative burdens and regulatory lag.[6]

Three PBR mechanisms are the focus of this document, and NERP suggests they be jointly considered and designed for NC electric utilities:

- Decoupling to remove the utilities' incentive to grow energy sales
- Performance incentive mechanisms (PIMs) to create new earnings opportunities (or penalties) for targeted outcomes
- Multi-year rate plans (MYRP) to increase the time between utility rate cases in order to introduce cost containment incentives for the utility and reduce regulatory lag

PBR design and adoption is a significant undertaking. Critical details must be considered and worked through, typically through a regulatory proceeding that includes utility proposals, input and counterproposals of other stakeholders, and eventual decision-making by utility regulators. As outlined below, a probable first step will be enactment of PBR-enabling legislation.

Companion documents

In addition to this guidance document, NERP has produced:

- Draft legislation authorizing the NCUC to pursue PBR
- A fact sheet providing an introduction to PBR, an overview of the draft legislation and a summary of this guidance document
- Case studies discussing:
  - how PBR has been implemented in Minnesota, and
  - how North Carolina has implemented revenue decoupling for natural gas utilities.

Context and history

On October 29, 2018, Governor Roy Cooper issued *Executive Order 80: North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy*.[7] The Order established the North Carolina Climate Change Interagency Council and tasked the Department of Environmental Quality (DEQ) with producing a clean energy plan.

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[5] According to NARUC, "In Cost of Service Regulation, the regulator determines the Revenue Requirement—i.e., the 'cost of service'—that reflects the total amount that must be collected in rates for the utility to recover its costs and earn a reasonable return." https://pubs.naruc.org/pub.cfm?id=538E730E-2354-D714-51A6-5B621A9534CB. Under the proposed PBR system, the utility would still file cost of service studies in a general rate case and those studies would be the basis for establishing the total revenue required and the allocation to the customer classes. The PBR adjustments discussed in this document would be increments or decrements to that base.

[6] Regulatory lag results when a utility's costs change, either up or down, in between rate cases. Issues result when regulatory lag creates financial incentives for utilities that are not aligned with public interest. For more detail, see Appendix A.

[7] Executive Order 80. https://governor.nc.gov/documents/executive-order-no-80-north-carolinas-commitment-address-climate-change-and-transition.

DEQ convened a group of stakeholders that met throughout 2019. In October 2019, DEQ released the *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System* (CEP).[8] Recommendation B-1 of the CEP states: "Launch a NC energy process with representatives from key stakeholder groups to design policies that align regulatory incentives and processes with 21st Century public policy goals, customer expectations, utility needs, and technology innovation." That process was launched as NERP, which met throughout 2020.

Also relevant to this document is NC Senate Bill 559,[9] introduced in 2019. SB559 eventually passed and authorized utilities to petition the NCUC to recover certain storm recovery costs through securitization. The initial version of the bill included a separate section that would have authorized the NCUC to accept MYRP proposals from utilities. After concerns were raised by a large number of stakeholders, and no adequate compromise was found, that section of the bill was dropped. NERP has attempted to recognize the advantages of – and resolve the objections to – the MYRP as proposed in SB559.

NERP process

The NERP process, facilitated by Rocky Mountain Institute and the Regulatory Assistance Project, brought together roughly 40 diverse stakeholders to consider four main avenues of utility regulatory reform:

- PBR
- Wholesale market reform
- Competitive procurement of resources
- Accelerated retirement of generation assets

The NERP stakeholder group identified ten desired outcomes of reform in North Carolina, as shown below in Figure 1. Of those, the focus of PBR deliberations were:

- Regulatory incentives aligned with cost control and policy goals
- Carbon neutral by 2050
- Affordability and bill stability

[8] *North Carolina Clean Energy Plan: Transitioning to a 21st Century Electricity System*, NC Dept. of Environmental Quality, Oct. 2019, https://files.nc.gov/governor/documents/files/NC_Clean_Energy_Plan_OCT_2019_.pdf.

[9] SB559, Storm Securitization, passed Oct. 2019, https://www.ncleg.gov/BillLookUp/2019/s559.

Outcome Category	Outcome
Improve customer value	Affordability and bill stability
	Reliability
	Customer choice of energy sources and programs
	Customer equity
Improve utility regulation	Regulatory incentives aligned with cost control and policy goals
	Administrative efficiency
Improve environmental quality	Integration of DERs
	Carbon neutral by 2050
Conduct a quality stakeholder process	Inclusive
	Results oriented

FIGURE 1: PRIORITY OUTCOMES IDENTIFIED BY NERP STAKEHOLDERS

PBR Study Group

A subset of NERP participants volunteered to serve on a PBR study group and began meeting in May 2020. Three subteams were created to discuss: revenue decoupling, multi-year rate plans (and earnings sharing mechanisms), and performance incentive mechanisms. (See page 2 for a list of PBR study group and subteam members.)

The subteams regularly presented their work to the PBR study group for feedback. The study group presented a straw proposal to the larger NERP group, detailing how a comprehensive PBR package might be designed for NC. Feedback was received from NERP participants and incorporated into the eventual design recommendations detailed below.

What problems is PBR solving?

Performance-based (or outcome-based) regulation is intended to motivate utilities to accomplish outcomes that customers or society deem desirable. In doing so, PBR can help shift utility focus away from certain outcomes that may be inadvertently incentivized by traditional ratemaking.

In the current system, utilities increase their revenues by increasing electricity sales in the short term (known as the throughput incentive) and increase their profits by favoring rate-of-return-based utility capital spending over other options as the method by which to solve identified grid needs (known as the capital expenditure, or capex, bias).

The throughput incentive arises from the fact that, in traditional ratemaking, prices are set primarily on a volumetric basis based on a historic level of costs and sales, normalized and adjusted for known and measurable changes. After volumetric prices are set in the rate case, if utilities sell more electricity than was estimated in the rate case, they increase their revenues and therefore profits (assuming costs do not fluctuate significantly based on sales volume in the short term).

The capex bias originates from the fact that utilities are typically allowed to earn a regulated rate of return (profit percentage) on shareholder capital that they invest in physical assets, such as power plants, transmission wires, distribution grid assets, company trucks, computers, buildings, etc. This results in utility preference for capital expenditures as solutions for grid needs, whereas many cost-saving or emissions-reducing opportunities result from program innovations, such as customer efficiency programs, that fall into the category of operating expenditures (opex), on which no rate of return is earned.

Even as NC's population is growing, the demand for electricity from existing customers continues to remain flat, and in some cases has declined compared to historical years as more customers are investing in their own on-site generation and energy efficiency measures. This changing economic landscape can further drive the throughput incentive and capex bias, the two main limitations of the current framework.

PBR offers a set of tools that can create utility incentives that are more aligned with customer and societal goals. For example, PBR can make it more likely that clean energy, energy efficiency, and carbon reduction goals are achieved. There is no one uniform combination of PBR tools. Some states have implemented one or two reforms; others are examining comprehensive measures. The reforms discussed below were the focus of NERP and have been implemented or are currently being discussed in other states.

See Appendix B for a diagram depicting potential interactions and coordination between the different mechanisms within a PBR framework.

Other ongoing processes and trends impacting PBR

The world in general, and North Carolina in particular, are in an exciting period of transition to a cleaner and more equitable electricity system. As a result, there are emerging technologies, rapidly changing cost dynamics, potential new policies, and revisions of old policies all up in the air at once. NERP has designed recommendations for PBR implementation based on its best estimate of where these balls might land.

In considering any PBR proposal that comes before it, the NCUC will have to evaluate where these processes stand and how the PBR mechanisms interact with them. Some examples of ongoing processes include:

- other proposals emerging from the NERP process (securitization of uneconomic coal assets, all-source competitive procurement, and wholesale market study),
- an analysis of carbon reduction policies under the A-1 recommendation of the CEP including accelerated coal retirements; a Clean Energy Standard or other clean energy policy (e.g., Energy Efficiency Resource Standard or Peak Reduction Standard); an offshore wind requirement; a carbon adder or shadow carbon price for purposes of planning and/or dispatch; and/or a market-based cap and invest program (e.g., joining the Regional Greenhouse Gas Initiative),
- the Southeastern Energy Exchange Market proposal being advanced by Duke Energy and other Southeast utilities,
- the trend toward vehicle electrification and state strategies for accelerating adoption of electric vehicles, including the NC Zero-Emission Vehicle Plan, Duke's EV pilot, distribution of VW Settlement Funds, and NC signing onto the multistate Medium- and Heavy-Duty ZEV MOU,
- the low-income collaborative proposed by Duke Energy in the current NC rate cases,
- the comprehensive rate design study proposed by Duke Energy in the current NC rate cases,
- implementation of changes to the EE/DSM incentive ordered by the NCUC in its October 2020 order, including new incentive levels and use of the Portfolio Performance Incentive and Utility Cost Test,[10]
- any changes to net metering policy,
- NCUC orders that will be issued on DEC and DEP rate cases and Duke's Integrated Resource Plan,

[10] Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms, Oct. 20, 2020, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=5aaea5ce-6458-41fe-ab2d-14d86881092d.

- the NC Transmission Planning Collaborative's study of onshore transmission investments necessary to integrate up to 5,000 MW of offshore wind (expected completion in early 2021),
- the newly established nonprofit NC Clean Energy Fund that will make funding available for clean energy projects that are traditionally difficult to finance, and
- Duke Energy's implementation of its Integrated System & Operations Planning (ISOP) process that will allow integration of new technologies and customer programs as technology and policy pertaining to generation, transmission, and distribution continue to evolve.

Some of these factors are flagged in the specific recommendations below.

Statutory authority and rationale for legislation

Legislation has been used in many states to provide explicit authority to utility commissions to implement or approve proposed PBR mechanisms. In the expectation that the NCUC would welcome specific authorizing legislation, NERP has drafted legislation authorizing the NCUC to pursue comprehensive PBR. It specifies deadlines and baseline requirements that any PBR package should meet, but is minimally prescriptive so that the NCUC has leeway to consider the many PBR design parameters in a manner that best meets the needs of the state at the time the mechanisms are established.

NERP RECOMMENDATIONS FOR PBR TOOLS

After studying the PBR mechanisms described below, NERP has come to the conclusion that a comprehensive package of revenue decoupling, multi-year rate plan, and performance incentive mechanisms would best address North Carolina's changing needs. The three sub-sections below explain how each mechanism works, how the mechanisms interact with each other, what recommendations NERP makes for their design, and key issues that need attention from the NCUC. NERP participants offer the following takeaways and recommendations from our deliberations on PBR to inform the NCUC's thinking.

Revenue Decoupling

Definition

Decoupling breaks the link between the amount of energy a utility delivers to customers and the revenue it collects, thus minimizing the throughput incentive described above. Allowed revenue is set in a rate case as usual. Rather than setting prices in the rate case and leaving them unchanged until the next rate case, under revenue decoupling prices are set in the rate case but adjusted up or down over the course of the rate effective period to ensure that collected revenues equal allowed revenues (no more and no less). See Figure 2.

Traditional System:

Revenue = Fixed Price × Sales

Decoupled System:

Price = Fixed Revenue ÷ Sales

Comparison with current system

Currently, for many residential and smaller commercial and industrial rate schedules, there are no demand charges and a majority of fixed costs are recovered through variable energy rates (cents per kWh). When fixed costs are recovered through a variable rate, a utility's margin is higher when it increases its sales and lower when it decreases its sales. Consequently, the utility has a financial incentive to increase sales and a disincentive to reduce sales. Decoupling seeks to break this linkage.

This incentive and linkage have already been recognized by the NCUC in its approval of net lost revenue mechanisms within utility energy efficiency and demand side management riders.

The net lost revenue (NLR) mechanism addresses this issue by removing the financial disincentive to reduce sales when the utility implements an approved DSM/EE program. Decoupling goes a step further by removing the incentive/disincentive to increase or reduce sales in all situations. This would include reduced sales from DER deployment, reduced sales from customer efficiency and conservation efforts that are not part of a utility program, and reduced sales from certain rate designs or other utility programs that may not qualify as an approved DSM/EE program. It would also break the incentive for increases in sales from electric vehicle charging and economic development. Since some of these sales may align with the public interest, it is important to implement decoupling as part of a comprehensive PBR package to ensure that the utility still has an incentive to beneficially grow sales in areas that are aligned with public interest.

Decoupling is one part of broader PBR plan

Many states implement decoupling as part of a broader PBR package and there are synergies between the mechanisms. For example, PIMs can be used to incentivize electric vehicle charging or economic development when decoupling removes these incentives from the current ratemaking structure. Additionally, where decoupling removes a disincentive for the utility to reduce sales through energy efficiency or other means, PIMs can go a step further and create a positive incentive for the utility to reduce sales. Decoupling also works well with multi-year rate plans. The MYRP can provide for small, annual changes in rates, and the decoupling mechanism can true-up the sales that the MYRP rates are based on to actual sales realized during each year of the plan. Thus, decoupling and MYRPs together can reduce the need for frequent rate cases and can break the linkage between utility sales and profit margin.

Alignment with the goals of the Clean Energy Plan

Decoupling is aligned with the broader CEP goals. First, the CEP supports increased DERs, EE, and DSM, all of which decrease sales per customer. Decoupling removes the sales-related disincentive utilities have to promote and utilize these resources. Decoupling is also an alternative to increasing fixed charges in the rate design structures for residential and smaller commercial and industrial customers. If fixed costs are recovered through fixed charges and variable through variable, this also removes the throughput incentive for utilities. However, increasing fixed charges also decreases variable charges, which reduces the incentive for customers to be energy efficient, conserve energy, and/or invest in DERs. Additionally, higher fixed charges, on average, place a higher energy burden on low-income customers, who tend to have lower usage per customer. Reducing the incentives for EE, conservation, and DERs and placing a higher energy burden on low-income customers are contrary to the goals of the CEP. Decoupling is therefore better aligned with the goals of the CEP than increasing fixed charges as a means of removing the throughput incentive.

Experience in other states and jurisdictions

North Carolina has experience with decoupling in the natural gas distribution sector.[11] In addition, electric decoupling has been adopted successfully in 17 states and another 7 states have pending actions. Rate adjustments under decoupling are typically small. According to a 2013 report produced for the American Council for an Energy-Efficient Economy and the Natural Resources Defense Council, almost two-thirds of adjustments made under decoupling were within 2% of the retail rate and 80% within 3%. Such adjustments are modest compared to other utility expenses that influence rates.[12]

Design Details of Decoupling and NERP Recommendations

The utility's proposed decoupling mechanism must be evaluated to ensure that it will produce just and reasonable rates and is consistent with the public interest, including the goals of the CEP. NERP explored several key design components of decoupling mechanisms, and has the following recommendations.

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[11] Case Study: Natural Gas Decoupling in North Carolina, NERP, December 2020, available here: https://deq.nc.gov/CEP-NERP.

[12] https://www.aceee.org/sites/default/files/publications/researchreports/u133.pdf

Decide what is covered

Affected Classes: Because the primary rate schedules that recover fixed costs through variable rates are the residential and small to medium general service, we recommend that these classes be included. The rate design for large general service includes demand charges and other provisions to recover more of the fixed costs through fixed charges. Also, lighting rate schedules generally recover fixed costs through fixed charges. When only variable costs are recovered through variable rates, there is no throughput incentive (revenue and costs go up or down proportionally and there is no impact to margin from higher or lower sales levels). Large general service and lighting do not necessarily need to be included for the decoupling mechanism to be effective and the NCUC may determine that it makes more sense to exclude them from the mechanism. However, attention would need to be paid to how excluding these customers from decoupling might impact the design of a utility's MYRP.[13]

Including small to medium general service in the decoupling mechanism would introduce a complexity that NERP did not have time to work through. Decoupling would replace the current net lost revenue mechanism recovered through the DSM/EE rider for classes participating in decoupling. Because there is only one general service rate in the DSM/EE rider for all three general service classes (small, medium, and large), it may not be feasible to include net lost revenues for only one of the three sizes in the rider. Consideration also needs to be given to small and medium general service accounts that can currently opt out of the net lost revenue mechanism and how that will be addressed with decoupling.

Costs to include:

- Recommend including all functions (generation, transmission, and distribution). In order for the mechanism to be effective and completely address the throughput incentive, it should not exclude any function included in the utility's bundled rate.
- Recommend including base rates only and excluding riders that have separate true-up mechanisms. If a rider already has a mechanism to true-up for sales volume (like fuel), then it should be excluded from the decoupling mechanism. If a rider does not have a separate true-up mechanism for sales, it may be included.
- The PBR study group considered recommending excluding EV charging sales in order to maintain the utility incentive to promote vehicle electrification. However, the only state where we have seen this done is Minnesota, and it may overly complicate the mechanism. Therefore, NERP recommends including EV charging sales in the decoupling mechanism and simultaneously adopting a PIM related to EV adoption and/or smart charging.

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[13] Large industrial customers are excluded from decoupling in some states on account of possible rate volatility should a single very large user leave the utility territory or change operations. Different treatment between customer classes is complicated, however, when decoupling is part of a MYRP framework. In many states with comprehensive MYRPs , such as California, Minnesota, Hawaii, and Massachusetts, decoupling is applied to all major customer classes. See Regulatory Assistance Project, Revenue Regulation and Decoupling: A Guide to Theory and Application, November 2016. http://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf; Minnesota Public Utilities Commission, "Order Approving True-Ups and Requiring Xcel to Withdraw its Notice of Changes in Rates and Interim Rate Petition," March 13, 2020.

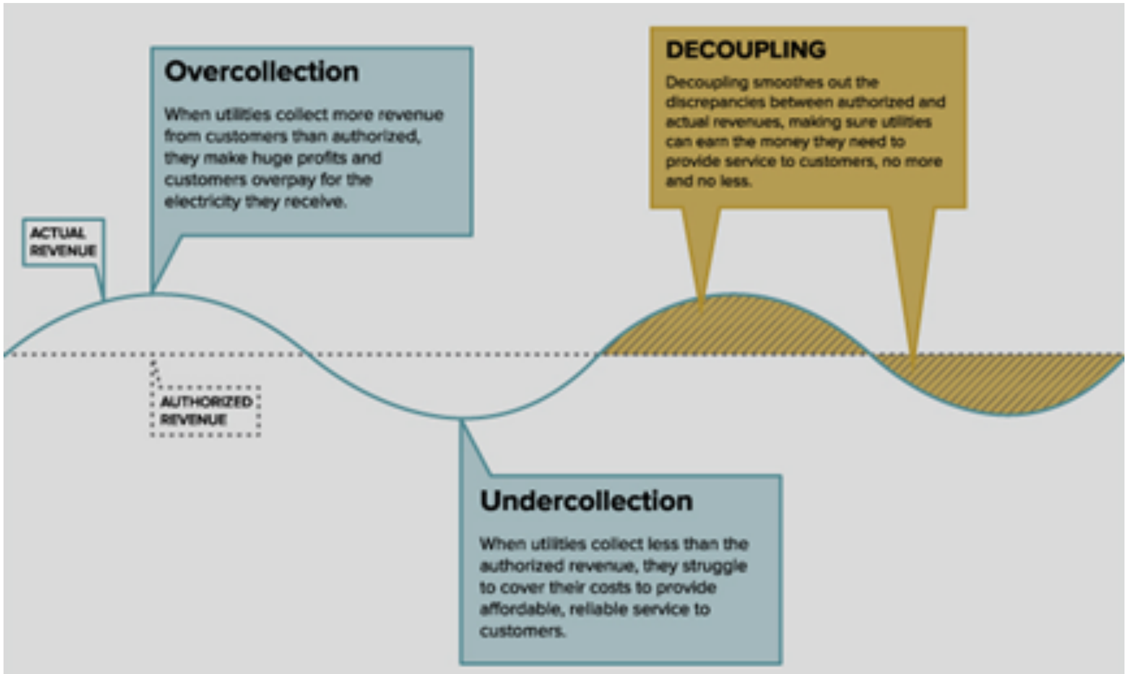

FIGURE 2: HOW DECOUPLING SMOOTHS OUT REVENUE FLUCTUATIONS[14]

Choose how to adjust utility revenue

The team explored several methods of adjusting the annual revenues under a decoupling mechanism and recommends consideration of the following two options: Revenue Per Customer (RPC) and Attrition Adjustment.

- RPC – allows for increases in revenue as new customers are added to the system, but mitigates changes in revenue driven by changes in usage per customer. In the initial base rate case, a revenue requirement per customer is set for the affected classes. Periodically, the actual revenue received from a class is compared to the target revenue per customer times the number of customers. Any excess or shortfall is deferred and returned to or collected from customers over the following year through adjustments to the customer class-specific rates. In addition, the tariff rates used going forward may be adjusted to reflect changes in usage per customer. This going-forward adjustment would need to be made in conjunction with any adjustments in the MYRP.

  Target revenue = number of customers x revenue requirement per customer

  This method is fairly straightforward and consistent with the current mechanism for gas utilities in NC; however, some NERP participants expressed concerns that actual costs per customer may decline over time, especially if generation assets (which depreciate over time) are included in the mechanism. If this is the case, some experts suggest that an attrition adjustment method may be more appropriate.[15]

- Attrition - adjusts the fixed level of revenue to be collected based on changes in costs and sales. This method may be appropriate when generation assets are included in decoupling. Just like with RPC, the actual revenue received from a customer class is compared to a target level of revenue, and any excess

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[14] Nissen Will, "Strategic electrification and revenue decoupling: different purpose, same goal," May 2, 2018, Fresh Energy, https://fresh-energy.org/strategic-electrification-and-revenue-decoupling-different-purpose-same-goal/.

[15] Migden-Ostrander, J., and Sedano, R. (2016). Decoupling Design: Customizing Revenue Regulation to Your State's Priorities. Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/knowledge-center/decouplingdesign-customizing-revenue-regulation-state-priorities

or shortfall is deferred and returned to or collected from customers over the following year through adjustments to the customer class-specific rates. However, the target revenue is based on the actual costs incurred over the same period and may be based on a formula rate template or agreed-upon formula adjustments to the rate case test year cost of service study. These “attrition review” proceedings are sometimes referred to as “mini-rate cases” but are a streamlined alternative to full-blown rate cases.

It should be noted that, under both types of decoupling, the going-forward adjustments would need to be coordinated with adjustments under the multi-year rate plan. This linkage is one way in which decoupling and MYRP work well together. MYRP involves a detailed analysis of how utility revenue should be allowed to adjust over time, while decoupling ensures that the allowed revenue is recovered (but not more or less than the allowed revenue).

If both decoupling and a MYRP with a revenue cap are adopted, the details of the two mechanisms must be determined together. The MYRP will likely inform how allowed revenues adjust each year, while decoupling will adjust customer rates so collected revenues equal allowed revenues. Options to adjust revenues may be based on inflation or other index, multi-year cost forecasts, customer growth, or a hybrid approach.

Select how to handle refunds or surcharges.

The process for the annual adjustment to rates should be efficient and transparent. NERP recommends considering caps on annual impacts to customers, with any additional amounts deferred into a future period. NERP also recommends considering design options for handling refunds and surcharges that encourage greater energy efficiency.

In terms of frequency of adjustments, NERP recommends decoupling price adjustments once a year. Some mechanisms are updated monthly, but that could lead to customer confusion with too-frequent price adjustments. According to a 2012 survey,[16] over two-thirds of electric utility decoupling true-ups were conducted on an annual basis.

Multi-year rate plan & earnings sharing mechanism

Definition

A MYRP begins with a rate case that sets the utility base revenues for the test year, based on the normal ratemaking process.

Under a MYRP, the revenue requirements necessary to offset the costs that are contemplated to occur under a plan approved by the NCUC would be set for multiple years in advance (typically 3–5 years). Utility compensation would be based on forecasted costs that are expected under the NCUC-approved plan, rather than the historical costs of services. Customer rates would be reset annually through NCUC review under the terms set out for the MYRP.

This approach can create added incentives for the utility to contain costs and can also reduce the regulatory costs from more frequent rate cases. The terms of a MYRP often include the following:

- A moratorium on general rate cases for longer periods (the term of the MYRP).
- Attrition relief mechanisms (ARMs) in the interim to automatically adjust rates or revenue requirements to reflect changing conditions, such as inflation and population growth.

[16] Morgan, P. *A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations.* Graceful Systems LLC, rev. February 2013, https://www.raponline.org/wp-content/uploads/2016/05/gracefulsystems-morgan-decouplingreport-2012-dec.pdf.

- MYRPs can (1) mitigate the regulatory lag associated with certain utility assets, such as grid investments and DERs, (2) give an incentive for utility cost containment by setting a framework for predictable revenue adjustments into the future.
- To maintain or pursue other regulatory and policy goals, MYRPs should be combined with performance incentive mechanisms (PIMs) (sometimes considered "backstop" protections for reliability or other services), an earnings sharing mechanism, and other tools.

Comparison with current system

The current system in NC is a traditional cost of service (COS) ratemaking system, which uses historical test years for base rate cases. This system has evolved over the years with the additions of selected cost recovery riders/clauses (e.g., fuel, etc.).

The types of assets to be added to the utility system in the future (renewables, energy storage, and grid improvements) will consist of a series of smaller, more frequent projects, and the addition of any large, central station generation assets will become rarer and rarer. The existing base rate case process does not fit this future well – the utility suffers significant regulatory lag, and so must file rate cases frequently, even annually. Utilities do have the incentive to reduce their costs between rate cases, but when rate cases become so frequent that they are almost annual, this cost reduction incentive is reduced. The NCUC still determines in each rate case what a reasonable level of costs is, but there is less incentive for the utility to try to drive costs below this level.

NERP believes that modifying the existing COS regulation to include a combined package of performance-based ratemaking provisions, including establishing MYRPs with an earnings sharing mechanism, revenue decoupling, and PIMs, will facilitate accomplishment of the goals delineated in the CEP.

MYRPs are one part of a broader PBR plan

MYRPs seem to work well with decoupling – many states currently use both at the same time. Additionally, MYRPs can work well with PIMs by establishing the cost recovery plan for investments that will achieve a goal and then creating a financial incentive or penalty for achieving or failing to achieve that goal. For example, to encourage increases in electric vehicle adoption or distributed energy resources, a multi-year rate plan can include the investments the utility must make to achieve these goals and then a PIM can attach a financial incentive to the goal. Neither a PIM without the enabled cost recovery through a MYRP, nor a MYRP without the accountability of a PIM, are as effective as the two mechanisms working in combination.

MYRP alone would not do anything to specifically address other policy goals such as the reduction of household energy burden, however. Addressing these key goals, and others under the CEP, would require the use of specific PIMs, or other requirements being placed on the utility, along with implementing the MYRP. See also the section below on PIMs.

Because of the complementary nature of the mechanisms, NERP recommends that MYRPs, decoupling, and PIMs be implemented in combination as part of a comprehensive PBR package.

Alignment with the goals of the Clean Energy Plan

One of the top three desired outcomes identified by NERP is to create "utility incentives aligned with cost control and policy goals."

MYRPs may give the utility the incentive to control and reduce its costs by giving it the opportunity to keep some of the cost savings as long as the MYRP is coupled with an earnings sharing mechanism. This cost containment incentive could potentially help address the utility's capex bias by motivating the utility to choose the most cost-effective solutions for grid needs, regardless whether they are capex or opex.

The effect of MYRPs in reducing regulatory lag on the kinds of new investments needed under the CEP is another key alignment of utility incentives with policy goals.

Also, page 12 of the CEP states:

> *The following overarching recommendations are critical to the transition and will drive the priorities identified by the stakeholders:*
> - *Develop carbon reduction policy designs for accelerated retirement of uneconomic coal assets and other market-based and clean energy policy options.*
> - *Develop and implement policies and tools such as performance-based mechanisms, multiyear rate planning, and revenue decoupling, that better align utility incentives with public interest, grid needs, and state policy.*
> - *Modernize the grid to support clean energy resource adoption, resilience, and other public interest outcomes.*

Significant investments will need to be made to modernize the grid consistent with these recommendations. MYRPs are a way to address the current financial disincentive that utilities have to make significant investments in the grid (see Appendix A) and therefore support the CEP priorities.

Experience in other states and jurisdictions

Fifteen US states have adopted electric utility MYRPs. Examples with a longer experience of MYRPs include Central Maine Power, MidAmerican Energy, and utilities in California and New York (MYRPs are also common in Canada, including Ontario). In our region, Georgia Power has been under MYRPs since the mid-1990s, and FP&L has used these repeatedly in Florida. The PBR study team reviewed a series of reports and studies of the other states to attempt to learn from the experiences of others. That review shows that while MYRPs show significant promise, there are many examples that indicate MYRPs must be enacted carefully. While our review was not exhaustive, the following are some of the key insights:

- Setting up MYRPs is a complicated process. It will require a lot of work from all stakeholders, and is fraught with risk of errors in the initial design that can have large consequences. The initial design can and should be improved over the years to correct any initial difficulties. Nevertheless, the PBR study team feels that the benefits of successfully implementing MYRPs – when coupled with an appropriately-designed earnings sharing mechanism – make this worth the effort, and the attendant risks can and should be mitigated and corrected.
- *The oversight of the NCUC should not be reduced.* Under a MYRP, the NCUC would be able to see the utility's business plans for a period of years into the future – which does not happen under the current system. This would allow for discussion of the types and amounts of assets to be added to the grid before the fact, instead of after the fact. Additionally, the NCUC would have detailed reviews of utility costs before each increase under a MYRP is authorized.
- There should be monitoring of utility service levels to mitigate the risk that utilities with a stronger incentive to reduce costs under a MYRP do not let existing service levels suffer. The use of a PIM with penalties for degradation of basic reliability and service levels outside of reasonable norms should be considered.

Examples of comments extracted from one report[17] that the team used as a reference:
"…It can be difficult to design MRPs that generate strong utility performance incentives without undue risk, and that share benefits of better performance fairly with customers. MRPs invite strategic behavior and controversies over plan design."

[17] Deason, J, et al. "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities." 2017, pp. 7-2,7-3. https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

"…The strengths and weaknesses of MRPs are not fully understood. Plan design continues to evolve to address outstanding challenges. Areas of recommended future research include impacts of MRPs (and reduced rate case frequency more generally) on service quality, operating risk, and levels of bills that customers pay."
"…We also found that the [productivity] growth of utilities that operated for many years without rate cases, due to MRPs or other circumstances, was significantly more rapid than the full sample norm. Cumulative cost savings of 3 percent to 10 percent after 10 years appear achievable under MRPs."

Design Details of MYRPs and NERP Recommendations

The mechanism for adjusting rates between rate cases must be clearly defined at the outset in the initial rate case. It is crucial for the rate adjustments to be defined at the outset to ensure a high degree of certainty of how the adjustments will be subsequently made. The utility is then clear about the extent to which a successful effort to control costs will result in increased earnings. Rider/trackers, true-ups, deferral accounts, and similar mechanisms are often used to address the need for additional expenditures or investments separately from rate cases to reduce the utility's exposure between rate cases.

The term of the MYRP

NERP recommends using a maximum of three years as the term of an initial MYRP, but this is a key term to be decided. While most MYRPs are 3-5 years, NERP recommends starting on the shorter end of this range until more experience with the mechanism is gained. At the expiration of the MYRP, the utility would have the right, but not the obligation, to come in and seek a base rate increase. The NCUC could also set a period within which the next base rate case must be filed (e.g., within 5 years).

The scope of the MYRP – which utility costs would be included?

The MYRP would not necessarily apply to all utility costs. The selection of which costs should be included in the MYRP is a key term to be decided, and each of the other states studied appears to have made specific decisions that fit their needs best.

MYRPs are not well suited for the ratemaking for large, single discrete investments, such as conventional power plants to be built and rate-based by the utility. These would normally be excluded from the MYRP design and handled separately, through a deferral or separate base rate adjustment.

Costs recovered through existing clauses, such as the fuel clause, would stay in their clause, and not be included in the MYRP.

Investment programs that are made up of a series of smaller utility assets constantly placed in service over time, such as a grid improvement plan, are very well suited to a MYRP.

An earnings sharing mechanism should be implemented

As the MYRP design sets utility revenue adjustments into the future and creates an incentive for the utility to keep its costs lower than those assumed in the MYRP, the possibility of either over- or underearnings during the term of the MYRP should be addressed when the MYRP is designed.

NERP recommends that the MYRP be accompanied by a preset earnings sharing mechanism (ESM). This would set out the details in advance of how the savings will be allocated between the customers and the utility stockholders.

The ESM could be symmetrical, with earnings above and below the allowed return shared between customers and stockholders according to the method set out by the NCUC when the plan is originally approved. The earnings sharing would be calculated on an annual basis.

Key issues requiring further discussion by the NCUC

Some MYRP design decisions that were either controversial or otherwise unresolved during NERP are flagged here as important for continued attention in the course of the PBR design process.

Determination of what costs to include under MYRP

The NCUC will need to determine whether a MYRP should cover base rates or be more narrowly constructed to only cover certain projected costs. This decision will inform the initial utility revenue requirement the NCUC approves at the beginning of a MYRP and how these allowed revenues might adjust in the interim years between rate cases. Commissions have typically allowed MYRPs to cover most utility costs to more comprehensively impact utility spending decisions.

If the scope of the MYRP is too narrow, the utility may not be able to commit to a multiple-year rate case "stay-out" or moratorium, depending on the planned investments over that period.

On the other hand, risks to ratepayers can be minimized by limiting the scope of costs that may be recovered under a MYRP, so some stakeholders favored using the following definition developed during SB559 negotiations:

> "Multiyear rate plan" means a rate mechanism under which the Commission sets base rates and revenue requirements for a multiyear plan period based on known and measurable set of capital investments and all the expenses associated with those capital investments and authorizes periodic changes in base rates during the approved plan period without the need for a base rate proceeding during the plan period.

Course correction if MYRP produces undesired outcomes

The longer stay-out period of a MYRP introduces risk that utility earnings could exceed or be below target levels, resulting in excessive over- or underearning by the utility. This may result from unforeseen events (e.g., tax law changes, economic recession) or from unexpected consequences of regulation design in the MYRP. Provisions can be made in the adoption of a MYRP for regulatory review at interim points in the plan, or for "reopeners" or "off ramps" at the determination of the NCUC, should those be necessary. It is useful for adopted regulations to specify that the NCUC may conduct such reviews or reopeners, including under what general conditions a plan may be revised, although the NCUC does not need to be overly specific on conditions under which this can occur.

Revenue adjustment mechanisms

See above under revenue decoupling for a discussion of the need to consider decoupling and MYRP revenue adjustments together.

Earnings sharing mechanism design

NERP recommends adopting a MYRP in conjunction with an ESM, but did not discuss the particulars of ESM design. Some issues to be resolved include whether there should be a deadband of over- or underearning in which no adjustment is made, and how sharing tiers should be designed.

Performance incentive mechanisms

Definition

Performance incentive mechanisms (PIMs) establish performance targets and tie a portion of a utility's revenue to its performance on meeting those targets. Targets are set to achieve outcomes that align with public policy goals.

Comparison with current system

One of the top three goals identified by NERP is to create "utility incentives aligned with cost control and policy goals." The COS model incentivizes utilities to sell more electricity and to add capital assets to their rate base, but those incentives do not necessarily align with public policy goals such as the need to quickly reduce carbon emissions or alleviate household energy burdens. Introduction of carefully designed PIMs into ratemaking procedures could bring utility incentives more in line with public policy goals, such as meeting the state's targets under the Clean Energy Plan, by linking a portion of utility revenues to utilities' performance in achieving those goals.

If a significant portion of a utility's revenues is tied to performance, PIMs can begin to shift a utility's investment or management focus away from increasing capital assets and toward the accomplishment of the public policy objectives reflected in PIMs, potentially mitigating the utility's capex bias.

North Carolina has already started down the PIMs path, as the shared savings mechanism under the EE/DSM rider is a PIM incentivizing performance in the areas of energy efficiency and demand-side management.

PIMs are one part of broader PBR plan

As described elsewhere in this document, PIMs complement both decoupling and multi-year rate plans. Decoupling removes the utility's disincentive to promote energy efficiency and DERs, and PIMs can be designed to go further and create incentives for utilities to promote these programs. A MYRP creates an incentive for a utility to cut costs, and it can be paired with PIMs designed to make sure the cost-cutting does not occur in a way that negatively impacts essential functions such as customer service and reliability.

Alignment with goals of the Clean Energy Plan

The purpose of PIMs is to align utility incentives with public policy goals, which is one of the main outcomes sought by the CEP. In addition, the PIMs recommended below by NERP address the following CEP goals: carbon reduction, energy efficiency, affordability, and clean energy deployment.

The PIMs recommended below are those that seemed most useful to NERP participants. The NCUC could consider additional PIMs to help meet other goals and ensure successful implementation of PBR, as long as the desired outcomes are ones over which the utility has some level of control.

Experience in other states and jurisdictions

Several other jurisdictions have implemented, or are studying, PIMs. Two resources that relate their experiences are *Utility Performance Incentive Mechanisms: A Handbook for Regulators* (Whited, et al., 2015) and *PIMs for Progress* (Goldenberg, et al., 2020) (see References below).

Design Details of PIMs and NERP Recommendations

Metrics, Targets, and Incentives

The first step in establishing PIMs is to decide on the desired outcomes. For each outcome, it must be determined 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. The next step is to identify what metrics will be used to measure utility performance. The collection of some amount of baseline data is typically needed in order to determine how a utility's performance is changing over time and how a reward or penalty ought to be implemented.

Depending upon whether a reward or penalty is appropriate, and depending on the level of confidence in a particular metric, performance on selected metrics can be (1) tracked and reported, (2) scored against a target or benchmark that has been set, or (3) tied to a financial reward or penalty, at which point the mechanism becomes a PIM.

For PIMs, if the utility achieves its performance target, it can then receive a financial reward or it can avoid a penalty. PIMs can be either symmetrical or asymmetrical. If the PIM is symmetrical, the utility receives a financial reward for achieving the target as well as a penalty for falling short of the target. An asymmetrical PIM provides only a reward ("upside only") or only a penalty ("downside only").

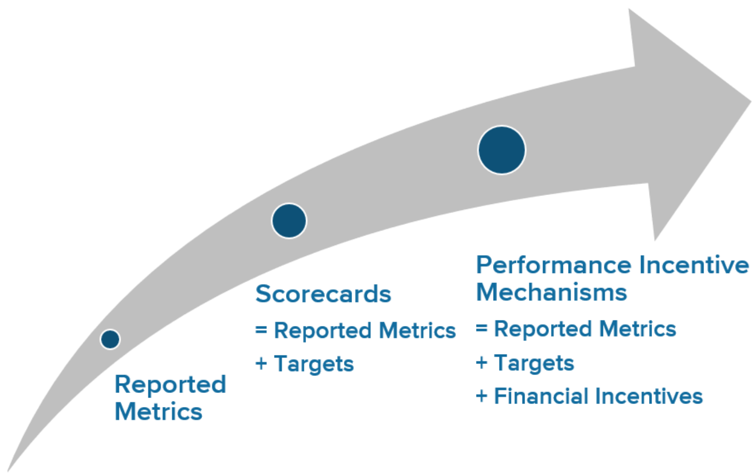

FIGURE 3: STAGES OF PERFORMANCE TRACKING
MCDONNELL, M., PBR DEEP DIVE WEBINAR: EXAMINING THE HAWAII EXPERIENCE, POWERPOINT, APRIL 2 2020.

PIMs principles

Agreeing on underlying principles to follow in designing PIMs can help align stakeholders on shared objectives. NERP agreed on these key principles to consider:

- 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.
- 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. A utility might prefer program-based PIMs, i.e., where incentives are awarded based on measurable actions, programs, and resources deployed or encouraged by the utility, over outcome-based PIMs given the risk that external factors may influence utility performance on the incentivized outcome (and therefore its compensation). Basing incentives on specific program results, e.g., kilowatt-hours saved through enrollment in an LED program, as opposed to outcomes, e.g., MWh saved system-wide, also makes symmetrical PIMs more of an option. However, a program-based PIM runs the risk of not achieving the desired outcome or decreasing the utility's flexibility to choose and amend the portfolio of programs and investments that best produces the desired outcomes.[18]

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

[18] For further discussion of activity-, outcome-, and program-based PIMs, see Goldenberg et al., *PIMs for Progress*, https://rmi.org/insight/pims-for-progress/.

be adjusted to improve performance. The Minnesota PBR case study that accompanies this document includes a diagram showing this iterative process as it was envisioned in Minnesota.[19]

Listed below are a number of performance outcomes discussed by NERP. Under most of the outcomes is listed a preferred metric for achieving that outcome, along with several alternative metrics. NERP recommends:

- At the outset, track as many of the metrics described below as are deemed useful and cost-effective, and any others identified by any stakeholder process or by the NCUC. This data collection will help to determine which metric is actually most useful in measuring performance.
- Track the overall performance for each adopted PIM or tracked metric and, where applicable, separately track the utility's performance in low-income counties, specifically Tier 1 and 2 counties.
- Establish a public dashboard for reporting performance on PIMs and tracked metrics.

Specific PIM outcomes recommended by NERP for NCUC consideration

Outcome: Peak demand reduction (or "Beneficial load-shaping" or "Aligning generation and load")
Preferred metrics: • Measurable load reduced/shifted away from peak based on measurement & verification from time-of-use (TOU) and other new rate designs (upside only, likely as shared savings) (program-based PIM) • Load factor for load net of variable renewable generation (upside only) (= average load not met by variable RE divided by peak load not met by variable RE) (Minnesota selected this as the metric for their PIM incentivizing "Cost-effective alignment of generation and load.")[20] • MW reduced from the utility's NCUC-accepted IRP peak demand forecast (for summer and winter peak) (upside only) (outcome-based PIM)
Alternative metrics: • enrollment (% of load or # of customers) in TOU rates or other advanced rates (symmetrical, likely as ROE adjustment) • MW demand response enrolled with TOU or other advanced rates (upside only, likely as ROE adjustment) • % of peak demand met by renewable energy (RE) or RE-charged storage and non-wires alternatives (upside only or, if symmetrical, set % target low and then progressively increase) • MW demand response utilized during critical peak periods identified for the purpose of utility tariffs using critical peak pricing (downside only with large deadband, i.e., penalty only for falling far short of target)
Notes: • This outcome serves two purposes: system efficiency and reducing need for new fossil fuel generation. • The preferred metrics listed above represent very different ways of looking at the problem. This area is ripe for innovation and requires further study and discussion before settling on an

[19] "Case Study: Minnesota Electricity Performance Based Rates," NERP, December 2020, page 5. Available here: https://deq.nc.gov/CEP-NERP

[20] Initial Comments of Fresh Energy, In the Matter of the Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations, Docket E-002/CI-17-401, pp. 2-6, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D012CC6E-0000-C510-A1A9-501BF633BC7D}&documentTitle=201912-157970-01.

approach. Even the definition of "peak" must be examined, as increased renewable generation in the future may lead to overall system peaks that are unproblematic because they are met by renewables, whereas the object of this PIM is to reduce demand that requires fossil fuel generation.

- Time-of-use rate design has been facilitated by the widespread installation of smart meters. Duke Energy is currently examining a suite of rate designs and DSM product bundles tailored to various customer segments that the utility believes can save customers money, drive overall system affordability, expand customer bill control, increase options related to clean energy and technology adoption, and create price signals that could offer significant peak demand reduction opportunities with minimal investment costs. Duke Energy believes that the same mechanism currently used for EE and DSM programs would be highly appropriate for measured and verified peak demand reduction and conservation from new rate designs. PIMs could be used to incentivize rate design that achieves desired NERP outcomes.

Outcome: Integration of utility-scale renewable energy (RE) & storage

Preferred metrics:
- Meeting interconnection review deadlines agreed on in queue reform (downside only)
- MW of RE interconnected over and above that required by law or policy (upside only)
- % MWh generation represented by RE

Alternative metrics:
- MW of utility-scale RE interconnected/yr
- MWh RE curtailment (symmetrical around a reasonable number)
- MWh of power from RE-charged utility-scale storage/yr (upside only)
- % RE capacity (MW) (tracked metric only)
- Avg. no. of days to interconnect utility-scale solar, below target(s) set forth in queue reform (upside only)

Outcome: Integration of DERs (RE/storage/non-wires alternatives)

Preferred metrics:
- 3-year rolling average of net metered projects connected (MW and # of projects) (upside only)

Alternative metrics:
- MW/MWh customer-sited storage in utility management programs
- # customers (and MW) participating in utility programs to promote customer-owned or customer-leased DER
- # customers (and MW) participating in utility programs to provide grid services (including RE, storage, smart thermostat, etc.)
- % of rooftop solar systems passing interconnection screens (upside only)

Notes:
- Revenue decoupling eliminates the throughput incentive but does not actively incentivize DER. Pairing this PIM with decoupling creates an incentive to increase DER.

• Consideration should be given to New York's shared savings program for non-wires alternatives projects, in which the cost of the solution (regardless of ownership) is recoverable in a 10- to 20-year regulatory asset.[21]

Outcome: Low-income affordability
Preferred metric: • % of low-income households, defined as those falling at or below 200% of the federal poverty level, that experience an annual electricity cost burden of 6% of gross household income or higher (upside only)
Alternative metrics: • Total disconnections for nonpayment • Usage per customer vs. historic rolling average, per class • Average monthly bill • % customers past due on their accounts • # customers on fixed-bill programs
Notes: • Why there is a need: In 2016, Duke Energy Carolinas had around 330,000 residential customers with household incomes ≤ 150% of the federal poverty level. They accounted for around 20% of DEC's total residential accounts. Those customers spent on average 10.5% of household income on energy (approximately 83% of which was for electricity and the rest for heating), compared to around 3% for DEC customers system-wide.[22] • There is a need to ensure affordability for other customers as well. Municipal utilities would benefit from any outcome that reduces production costs and commercial and industrial (C&I) customers want to keep NC rates competitive with other Southeast states. Metrics may need to be developed for these other classes of customers and for residential customers who do not qualify as low-income. Some of the alternative metrics listed above might be useful for some of these customers. • If a low-income rate pilot is adopted, it would help to inform the design of this PIM. Participants in the pilot would need to be selected randomly, and results would need to be reported, so that the energy burden of participating and non-participating households could be compared. • A lower fixed charge could help low-income customers and might be possible with decoupling, which shifts more of the fixed costs into rates.

Outcome: Energy efficiency
Notes: • Revenue decoupling eliminates the throughput incentive but does not actively incentivize energy efficiency (EE). Pairing this PIM with decoupling creates an incentive to increase EE. • This was one of the more important outcomes for NERP participants, but no preferred metric was chosen because the NCUC would need to consider any new EE incentives in conjunction with the existing EE/DSM incentive, which is a PIM using a shared savings mechanism. It was

[21] Trabish, Herman K. "Tackling the perverse incentive: Utilities need new cost recovery mechanisms for new technologies," Utility Dive, March 16, 2018, https://www.utilitydive.com/news/tackling-the-perverse-incentive-utilities-need-new-cost-recovery-mechanism/518320/.

[22] Direct testimony of Rory McIlmoil in Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, Docket No. E-7, Sub 1214, February 18, 2020, p. 35, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=11d407e8-1a85-487f-8548-ac2fa7cde2a5.

amended in October 2020 under NCUC Dockets No. E-2, Sub 931 and E-7, Sub 1032, with changes to take effect in 2022.[23] • If North Carolina enacts revenue decoupling for electricity, the lost revenue adjustment mechanism (LRAM) associated with the existing EE/DSM incentive will no longer be needed and will need to be removed by the NCUC for the classes included in decoupling. Particular attention will need to be given to how this is done for the general service class, if small and medium general customers are included in decoupling but large general service customers are not. There also needs to be consideration given to small and medium general service accounts that can currently opt out of the LRAM mechanism and how that will be addressed with decoupling. The recommendations below could be considered at that time.
Possible amendments to existing incentive: • The current incentive imposes a penalty for incremental annual savings below 0.5% and offers a bonus above 1%. The NCUC order directed the EE/DSM Collaborative to study the impact of switching to a step approach in which the incentive is scaled up or down linearly above a minimum and maximum level (so that there is a possibility of some bonus between 0.5% and 1% and a possibility of additional bonus above 1%). If the study shows this approach to yield greater savings, such a step approach could be adopted. That incentive should likely be capped at a certain percentage of costs (e.g., Minnesota caps incentives at 30% of program costs).[24] • Consider advantages/disadvantages of shared savings mechanism vs. using as the core metric either kWh saved, Btu saved (to give credit for electrification) and/or greenhouse gas emissions saved. • Most states base their goals on savings in a given year (called incremental annual savings, that measure savings from measures installed in that year). Illinois and, more recently, Virginia measure total annual savings (savings persisting from previously installed measures and new measures installed in that year). Incremental annual savings is a simple place to start, but over time total annual savings may be a good framework, because it addresses the persistent effect of short-term measures such as low-flow showerheads or behavioral EE programs.
Additional metrics to track or incentivize: • Low-income participation in EE programs • % participation per class • # of C&I customers participating (upside only, with the utility rewarded for implementing programs that cause fewer C&I customers to opt out, but not penalized for failing to do so, since the outcome is minimally controllable by the utility)

Outcome: Carbon emissions reduction
Preferred metric: • Tons of CO2 equivalents reduced beyond what is required by law or policy (with cost-effectiveness test, upside only)
Alternative metrics: • Reduction in carbon intensity (tons carbon/MWh sold) (symmetrical) • Carbon price used in IRP scenarios ($/ton, tracked metric only)
Notes:

[23] Order Approving Revisions to Demand-Side Management and Energy Efficiency Cost Recovery Mechanisms, Oct. 20, 2020, https://starw1.ncuc.net/ncuc/ViewFile.aspx?Id=5aaea5ce-6458-41fe-ab2d-14d86881092d.

[24] "Case Study: Minnesota Electricity Performance Based Rates," NERP, December 2020, Available here: https://deq.nc.gov/CEP-NERP

- Needs to be designed in accordance with any carbon policy resulting from the A-1 process. If no carbon reduction policy is achieved in the A-1 process, a PIM would be essential and could set benchmarks for reduction between now and 2050 that would incentivize meeting CEP carbon reduction goals.
- If this PIM were awarded on a dollar per ton basis, the NCUC could consult with the A-1 stakeholder group, who examined the effects of different carbon prices for future years.
- Consideration should be given to calculating and reporting (but likely not incentivizing) reduction in upstream methane emissions associated with gas burned in North Carolina, as these contribute significantly to climate change yet are not captured by the carbon accounting of the CEP. A PIM could eventually be appropriate if the state wishes to incentivize progress toward Duke Energy's goal, announced October 2020, of reducing upstream methane emissions in its natural gas distribution and power generation supply chains.[25]
- Any PIM in this area would need to be either based on North Carolina consumption with any incremental costs direct assigned to North Carolina customers or agreed to by regulators in both North Carolina and South Carolina.

Outcome: Electrification of transportation

Preferred metric:

- EV customers on TOU or managed charging (include home, workplace, fleets, and public charging) (upside only) OR
- MWh or % of EV charging load at low-cost hours (upside only)

Alternative metrics:

- Utilization of utility-owned public charging stations (upside only)
- Utility-owned charging in low-income areas (# or % chargers) (symmetrical)
- Customers enrolled in programs to encourage private charger installation (upside only)
- EV education (avoid rewarding $ inputs; maybe clicks on a web page; if expenditure metric, then downside only with spending cap)
- EV adoption
- CO2 avoided in transportation sector by electrification

Notes:

- Design in accordance with Duke Energy's EV pilot as approved November 2020.[26]
- Design depends on whether utility or others own charging infrastructure, since ROE on assets may be incentive enough.
- More research needed on how EVs can help with RE integration and how they can lead to reduced costs for all customers.
- Utility could use credits for off-peak charging but not put customers on TOU, or could use subscription pricing with managed charging. PIM should not constrain what method is used to promote off-peak EV charging.

Outcome: Equity in contracting

[25] "Duke Energy to reduce methane emissions in its natural gas business to net zero by 2030," https://www.duke-energy.com/_/media/pdfs/our-company/methane-reduction-fact-sheet.pdf?la=en.

[26] Order Approving Electric Transportation Pilot, In Part, Nov. 24, 2020, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=1c1665d0-d645-4293-82d8-ae9d7e672e3d.

Preferred metrics: • % of utility scale RE & storage suppliers that are 51% owned, managed, and controlled by one or more individuals who are socially and economically disadvantaged as defined by 15 U.S.C. § 637 (tracked metric only) • % of utility scale RE & storage suppliers that are 51% owned, managed, and controlled by one or more individuals who are women (tracked metric only)
Notes: • There is also a desire to achieve equity in use of utility programs across income levels, but that needs more discussion.

Outcome: Resilience
Preferred metrics: • Number of critical assets (see note below) without power for more than N hours in a given region (# of assets), N may be set as 0 hours or greater than the number of hours backup fuel is available • Critical asset energy demand not served (cumulative kW) • Critical asset time to recovery (average hrs)
Alternative metric: • Cumulative critical customer hours of outages (hrs)
Notes: • Recommended metrics revolve around impacts on critical community assets since that is the framework used in the PARSG (Planning an Affordable, Resilient and Sustainable Grid) project and in the state Resilience Plan. This approach is also being integrated into the NARUC-NASEO comprehensive system action plan that the NC delegation is considering. • Critical assets may include hospitals, fire stations, police stations, evacuation shelters, community food supply distribution centers, production facilities, military sites, etc. • Since resilience study is very much a work in progress in North Carolina, it is recommended that these initially be tracked metrics, with no incentive attached. • Efforts to develop resilience metrics are currently underway across organizations such as the DOE, FERC, EPRI and multiple state public utility commissions. The industry is lacking agreed-upon performance criteria for measuring resilience, as well as a formal industry or government initiative to develop consensus agreement.[27] As such, there are currently no standardized metrics to measure resilience efforts or to quantify the extent or likelihood of damage created by a catastrophic event. Resilience is addressed state-by-state, and oftentimes event-by-event. If different metrics, benchmarks, rewards or incentives are identified and developed for reliability and resilience,[28] there is a need to properly distinguish each, take into account the benefits for each, and differentiate how to separately determine the benefits, rewards and penalties for each.[29] • The metrics identified above are based on community impact driven resilience needs for critical infrastructure. It is based on current North Carolina state and local government led application of energy vulnerability and risk analysis framework that uses the Resilience Analysis Process (RAP) developed by the Sandia National Lab, which includes prioritization of grid-modernization initiatives that could achieve a desired set of resiliency goals for the community.

[27] IEEE Standards Association (2018) Grid Resilience and the NESC®.

[28] According to DOE, reliability refers to the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components. Resilience refers to the ability of a system or its components to adapt to changing conditions and to withstand and rapidly recover from disruptions.

[29] DOE (2017). See Key Findings at S-13: “There are no commonly used metrics for measuring grid resilience. Several resilience metrics and measures have been proposed; however, there has been no coordinated industry or government initiative to develop a consensus on or implement standardized resilience metrics.” https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

PIMs needed in conjunction with a multi-year rate plan

A MYRP provides an incentive to cut costs. Therefore, these two PIMs should accompany a MYRP to guard against detrimental cost-cutting in the areas of reliability and customer service. If there is no MYRP, the metrics could be simply tracked and reported.

Outcome: Reliability
Preferred metric: • SAIDI (performance year-over-year, excluding extreme event days, downside only, feeder-by-feeder) (see note below)
Alternative metrics: • CEMI4 (customers experiencing more than 4 outages of 1 minute or more per year) • SAIFI • Miles of vegetation management (tracked metric only; see note below)
Notes: • The design should be downside only because the utilities' performance on reliability is already high. Providing a reward for further improvement might not provide a net benefit to customers (point of diminishing returns). • The feeder-by-feeder specification prevents selective maintenance. Central Maine Power experienced a drop in reliability on certain feeders when they had a reliability PIM in conjunction with a MYRP. • Tracking miles of vegetation management would give the NCUC a way to ascertain whether the MYRP was resulting in decreased maintenance. But many other factors affect that metric, so a financial penalty could unfairly punish the utility for matters beyond its control, and a financial reward could perversely incentivize unnecessary vegetation work.

Outcome: Customer service
Preferred metric: • Third-party customer satisfaction survey (e.g., JD Power score or Net Promoter score) (downside only)

Key issues requiring further discussion by the NCUC

As the NCUC considers PIM implementation, it will have to consider all of the parameters discussed above. The NCUC will need to review a utility's proposed metrics and PIMs and determine whether they incentivize the right outcomes, whether they employ the best metrics to measure each outcome, whether the targets are at the right level, and whether financial incentives for each metric are at the right level and appropriate to include. NERP hopes that the suggestions made above will help with that process.

Options for designing incentives

NERP did not discuss the form that PIMs should take. The four most common design options are listed here. Each design option has advantages and disadvantages, and some PIMs incorporate aspects of more than one design.

- **Shared savings or shared net benefits**
  Incentives can be based on shared net benefits or savings that allow a utility to keep a portion of the net benefits or savings that are created by the achievement of a performance target. Net benefits are

calculated using the avoided costs that a utility would have incurred without the program minus the cost of the program itself.

- **Percentage adders based on spending**
  PIMs can allow a utility to earn a percentage return on their spending on particular programs, such as energy efficiency or DER initiatives, if they meet performance targets or program goals. This allows utilities to earn a return on expenses that would otherwise be a pass-through.
- **Fixed rewards or penalties**
  Utilities can earn or be penalized a fixed amount based on achievement of targets.
- **Adjustment to a utility's regulated ROE**
  PIMs can make a basis point adjustment of a utility's regulated ROE, which could more fundamentally impact utility investment decisions.

RECOMMENDED PROCESS FOR PBR DEVELOPMENT

PBR requires careful attention to key design details, especially for a comprehensive PBR approach as described here. NERP participants believe that enabling legislation will be beneficial to direct the next stage of PBR development, followed by a NCUC rulemaking process to adopt necessary rules for filing applications and criteria for evaluating them. Effective incentive regulation will also require ongoing monitoring and possible course corrections during a PBR regime (e.g., at the conclusion of a multi-year term, before advancing to the next term). This foretells the need for devoted attention and care from the NCUC and stakeholders to monitor utility performance and system outcomes, then make adjustments to guide utilities to continued improvement and value creation for customers.

Other states have applied a sequential process to develop and refine PBR, for example:

1. Articulate goals
2. Identify desired outcomes
3. Assess how current regulations meet or do not meet desired outcomes
4. Prioritize outcomes and identify PBR tools for further development
5. Design and iterate on PBR tools
6. Determine steps and requirements for implementation, including opportunity for evaluation

The NERP process has made substantial progress on the first four of these steps. A PBR process at the NCUC should seriously consider the conclusions reached by NERP, then follow the steps above, making sure to receive comment from as broad a group of stakeholders as possible, including any other relevant state agencies. Some specific steps that may be necessary are outlined below.

- First, the NCUC would lead a rulemaking process, to set up all of the filing requirements and procedures that any utility would need to follow to file a PBR application, including the criteria to be used by the NCUC in evaluating PBR applications. The NCUC should determine whether and in what form a stakeholder process should take place to gather input prior to a utility filing a PBR application.
- The utility would submit its PBR application as part of an initial base rate case. The utility would still file cost of service studies and those studies would be the basis for establishing the total revenue required and the allocation to the customer classes. The PBR adjustments discussed in this document would be increments or decrements to that base. The utility's accompanying PBR application would include:
  - a decoupling plan including proposed adjustment and true-up mechanisms
  - a multi-year rate plan including the planned investments that the utility proposes to undertake during the term of a MYRP
  - an earnings sharing mechanism
  - a set of proposed PIMs, scorecard targets or reported metrics
- In addition to all the normal rate case activities, the NCUC would need to:
  - review and rule on the proposed decoupling and MYRP designs and proposed PIMs

  - evaluate whether the planned investments are consistent with the goals of the CEP and the public interest and determine which of those planned investments would be allowed and what the allowed revenue increases would be over the term of the MYRP
  - for the customers included in decoupling, amend as needed the lost revenue adjustment mechanism (LRAM) that is part of the existing EE/DSM incentive, since decoupling adjusts revenue in a different manner
- Annually, the NCUC would review the results of the utility's operations during the prior year, including:
  - actual capital projects placed in service
  - utility earnings levels
  - utility sales and any adjustments needed due to a decoupling mechanism, including amounts to be refunded to or collected from customers based on the decoupling true-up mechanism and adjustments to rates going forward as a result of the mechanism
  - other utility revenue adjustments required by the adopted MYRP and ESM
  - utility performance against any adopted PIMs or tracked metrics to calculate penalties and incentives.

  After this review, the NCUC would approve the actual rates to be used in the subsequent year.
- NCUC rulemaking should outline what steps will be taken at the end of the initial MYRP period, including opportunities to add, delete, or adjust the approved set of PIMs to ensure they are capturing and driving desired utility performance.

Theoretical timeline

To help visualize how this process might unfold in North Carolina, NERP developed this entirely theoretical timeline:

- Legislation signed into law: June 2021
- NCUC issues rules for utility PBR applications: December 2021
- PBR application and base rate case filed by utility: July 2022
- NCUC proceeding to evaluate application: July 2022-March 2023
- NCUC order establishing PBR: March 2023
- First annual decoupling/MYRP true-up and PIMs review: March 2024

CONCLUSION

To summarize, NERP recommends that NCUC, subject to any guidance and timelines provided by legislation, begin as soon as possible a proceeding to develop rules under which a utility may file a comprehensive PBR application, including:

- Revenue decoupling excluding the large general service class to reduce the throughput incentive
- MYRP with an ESM and off-ramp to eliminate regulatory lag
- PIMs or tracked metrics to transition the utility revenue model toward achievement of regulatory goals, addressing the following outcomes: peak demand reduction, integration of DER and utility-scale RE and storage, low-income affordability, energy efficiency, carbon emissions, electrification of transportation, resilience, equity and – assuming a MYRP is adopted – reliability and customer service
- Provisions for annual or more frequent decoupling and MYRP true-ups and adjustment of PIM metrics, targets and incentive levels

Members of the NERP stakeholder group, in particular the PBR study group, stand willing to help the NCUC in its implementation of PBR, either in a stakeholder process or in any other way the NCUC deems appropriate.

REFERENCES

There are many resources on PBR. Here are some that NERP found most useful.

Cross-Call, Gold, Goldenberg, Guccione, and O'Boyle, *Navigating Utility Business Model Reform*, Rocky Mountain Institute (2018). Available at https://www.rmi.org/insight/navigating-utility-business-model-reform/.

Gold, R. et al. *North Carolina Can Boost Economy, Cut Utility Bills and Carbon with Energy Efficiency Efforts*, American Council for an Energy-Efficient Economy, September 23, 2020. https://www.aceee.org/research-report/u2007.

Goldenberg, Cara, Dan Cross-Call, Sherri Billimoria, and Oliver Tully, *PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals*, Rocky Mountain Institute, 2020, https://rmi.org/insight/pims-for-progress/.

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Lazar, Jim, et al. *Revenue Regulation and Decoupling: A Guide to Theory and Application*, Regulatory Assistance Project; 2016. Available at https://www.raponline.org/knowledge-center/revenue-regulation-and-decoupling-a-guide-to-theory-and-application-incl-case-studies/.

Littell, et al, *Next Generation Performance Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation*, Regulatory Assistance Project, 2017. Available at https://www.raponline.org/knowledge-center/next-generation-performance-based-regulation-emphasizing-utility-performance-unleash-power-sector-innovation/.

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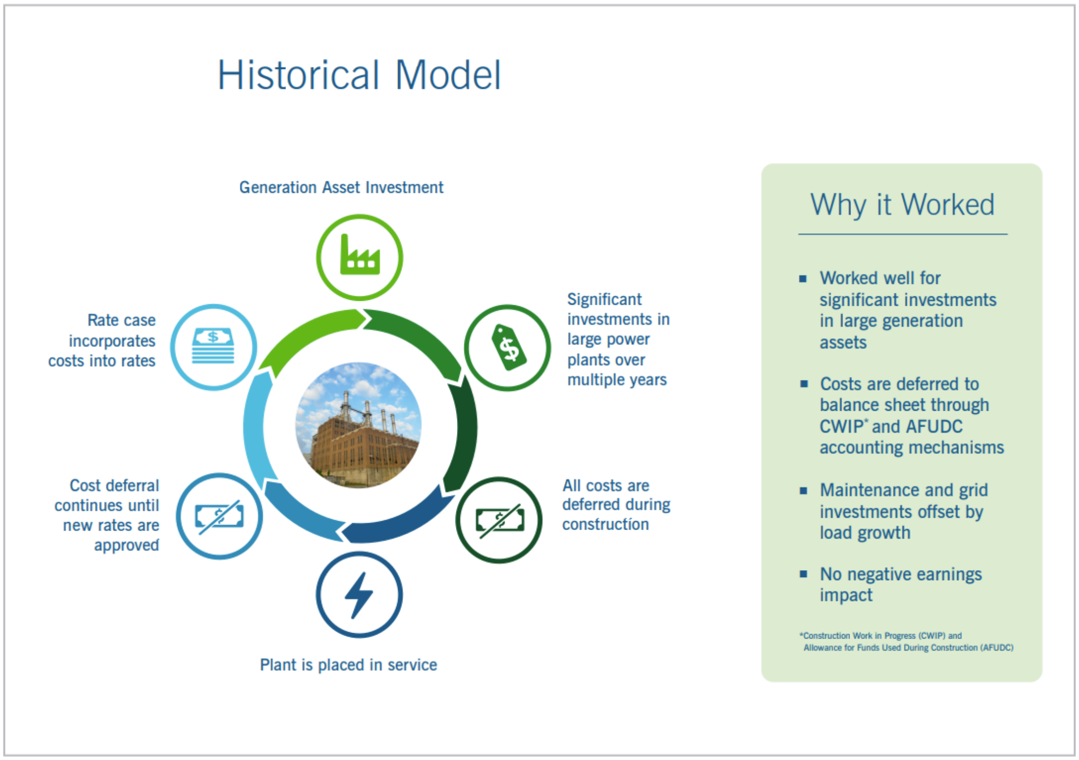
http://www.synapseenergy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf.

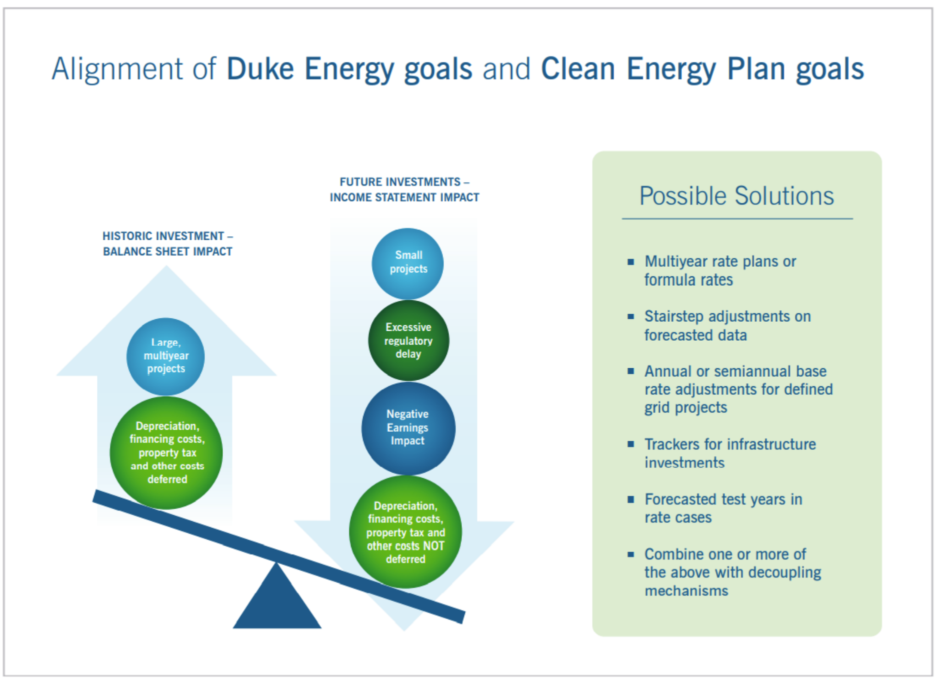
APPENDIX A

Solving for Regulatory Lag (Source: Duke Energy)

North Carolina Ratemaking and Recovery

The current regulatory system has served customers and utilities well for many decades. But today, utilities are shifting away from large-scale power plants toward modernizing the energy grid and adding more distributed energy. Therefore, a new model is needed to align the regulatory framework with investments in a 21st-century energy system.





Modern Cost Recovery for Electric Utilities

Many other states have adopted one or more cost recovery mechanisms that enable higher levels of grid improvement investment:

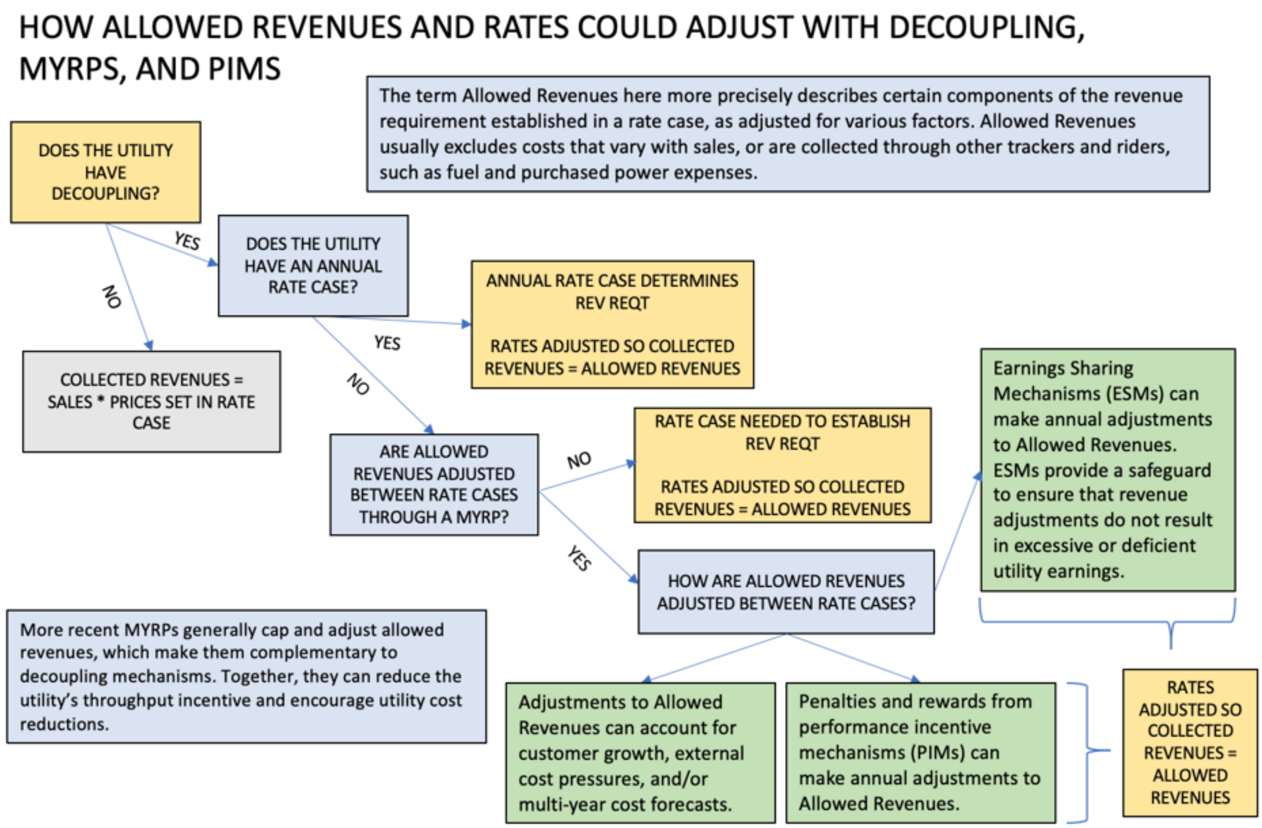
- 24 states have multi-year rate plans or formula rates
- 23 states have trackers for grid/electric infrastructure investments
- 30 states have forward test years (full or partial)
- Only 7 states have none of these mechanisms – including North Carolina

APPENDIX B

Flow Chart Diagram Depicting Potential Interactions and Coordination Between MYRP, Decoupling, and PIMs

Source: Rocky Mountain Institute

The following diagram depicts how several key PBR mechanisms operate together to adjust utility revenues and customer rates. It shows how revenue decoupling could operate with a MYRP that caps and adjusts a utility's revenues in the years between rate cases. Additional revenue adjustments resulting from performance incentives and an earnings sharing mechanism are also included to show how they might ultimately impact the revenues a utility is allowed to collect and the rates then charged to customers.



PART I. AUTHORIZE RATES USING ALTERNATIVE MECHANISMS

Section 1.(a) Article 7 of Chapter 62 of the General Statutes is amended by adding a new section to read:

"§ 62-133A. Performance-based rate methodology authorized.

(a) Declaration of Policy. - The General Assembly declares that utilities in the state have an important role to play in the transition to cleaner energy, and must be fully empowered, through regulatory tools and incentives, to achieve the goals of this policy. In combination with new technology and emerging opportunities for customers, this policy will spur transformational change in the utility industry. Given these changes, the legislature authorizes that the Utilities Commission's statutory grant of authority for rate making includes consideration and implementation of performance-based regulation (PBR) including: multiyear rate plans with earnings sharing mechanism, decoupling of utility revenues from energy sales, and performance incentive mechanisms to achieve just and reasonable rates and achieve its public interest objectives. The General Assembly also finds that the regulatory cost recovery mechanisms should better align the interests of customers and electric public utilities and that improvements should be made in the current rate making process to decrease the number of rate cases and reduce the regulatory lag that currently hinders certain capital investments, such as investments in the electric grid, storage or small scale renewables, and other technologies, necessary to support the clean energy transition. The PBR approach can be used to encourage: (a) alignment of electric utility incentives with customer and societal interests through regulatory mechanisms that motivate utilities to improve operations, increase program effectiveness, and better manage business expenses, (b) electric utility innovation in how it delivers service to customers; (c) electric utility investments to reduce carbon emissions, make the grid smarter, more resilient to adverse weather and to cyber and physical security threats, and capable of accommodating more renewable and distributed energy resources onto the system; (d) more efficient use of energy by customers; and (e) maintaining affordable and more predictable rates through annual rate adjustments spread over time. As such, the General Assembly declares that it is in the public interest to develop standards for performance-based regulation of electric utilities.

(b) Definitions. - For purposes of this section, the following definitions apply:

(1) “Performance-based regulation (PBR)” means an alternative rate making approach that includes (1) revenue decoupling; (2) multiyear rate plans with earnings sharing mechanism; and (3) performance incentive mechanisms.

(2) “Decoupling” means a ratemaking mechanism intended to break the link between a utility's revenue and the level of consumption of electricity by its customers.

(3) “Multi-year rate plan (MYRP)” means a ratemaking mechanism under which the Commission sets base rates based on a historic test year and revenue requirements necessary to cover new Commission-authorized costs that are expected to be incurred over a multi-year period through a plan which authorizes periodic changes in rates without a general rate application.

(4) “Earnings sharing mechanism” means a ratemaking mechanism that shares surplus or deficit earnings, or both, between utilities and customers.

(5) “Performance incentive mechanism (PIM)” means a ratemaking mechanism that links electric utility revenue or earnings to electric utility performance in targeted areas consistent with customer and societal interests and regulatory and public policy goals and includes specific performance metrics and targets against which utility performance is measured.

(6) “Distributed Energy Resource (DER)” means a device or measure that produces electricity or reduces electricity consumption, and is connected to the electrical system, either ‘behind the meter’ on the customer’s premises, or on the utility’s primary distribution system. A DER can include, but is not limited to, energy efficiency, distributed generation, demand response, microgrids, energy storage, energy management systems, and electric vehicles.

(7) “Tracking metric” means a methodology for tracking and quantitatively measuring and monitoring outcomes or utility performance, meaning that the data reflected by the unit of measurement is tracked and published to illuminate progress toward a particular regulatory outcome.

(c) Authorization. - Notwithstanding the methods for fixing rates established under G.S. 62-133, the North Carolina Utilities Commission is authorized to utilize and approve PBR mechanisms proposed by electric public utilities and/or other stakeholders and intervenors, including, but not limited to, revenue decoupling, MYRP with an earnings sharing mechanism, and PIMs.

(d) Rulemaking. - Within six months of the effective date of this act, the Commission shall issue an order adopting rules consistent with this act. The Commission may initiate a stakeholder process to inform its rulemaking. The rules should prescribe the specific procedures and requirements that an electric utility must meet when filing a PBR Application, the criteria for evaluating such an Application, and the process for addressing deficiencies through a remedy that may consist of a collaborative process between stakeholders and the utility to cure any identified deficiency in the Utility’s PBR Application in the event the Commission ultimately rejects a utility’s PBR Application.

(e) Application. - A PBR Application shall be made in a general rate case proceeding initiated pursuant to G.S. 62-133, and must include details of: (1) a decoupling rate adjustment mechanism; (2) a MYRP if desired by the electric utility (including proposed revenue requirement and rates for each year of the MYRP or method for calculating such); and (3) PIMs (including but not limited to targeted areas of energy efficiency, peak demand reduction, and renewable energy and DERs). It may also include proposed tracking metrics with or without targets or benchmarks to measure utility achievement, and other PBR mechanisms to support the clean energy transition. The following additional requirements apply:

(1) MYRP may include annual rate adjustments based on projected investments, formulas, indexes, or a combination thereof. If the MYRP includes rate increases based on forecasted planned investments, the Commission shall require the electric utility to include in its PBR Application major planned investments over the plan period, the schedule for completion of those investments, and an explanation as to why the investments are in the public

interest. If projected investments are not included in the MYRP rate adjustments until after the investments are in service, then the utility may request Commission approval to defer to a regulatory asset the incremental costs from the time the investment is placed in service until the costs are reflected in the MYRP rates.

(2) PIMs should be clearly defined, measurable with a defined performance metric, and reasonably within the utility's control. The incremental costs required to achieve a PIM shall, upon approval by the Commission, either be included in rates under a MYRP or deferred to a regulatory asset until such time as the costs can be incorporated into the utility's rates.

(f) When reviewing a PBR application, the Commission may approve PIMs proposed by the electric utility as part of a PBR application including the following:

(1) Rewards based on the sharing of savings achieved by meeting or exceeding a specific performance target;

(2) Rewards or penalties based on differentiated authorized rates of return on common equity to encourage utility investments or operational changes to meet specific performance targets;

(3) Fixed financial rewards to encourage achievement of specific performance targets, or fixed financial penalties for failure to achieve such targets; and

(4) Any other incentives or financial penalties that the Commission determines to be appropriate.

(g) The Commission shall approve the PBR Application by an electric utility only upon a finding by the Commission that such mechanisms are just and reasonable, and are in the public interest pursuant to G.S. 62-2(a). In reviewing any such Application under this section, the Commission may consider whether the Application, as proposed: (i) assures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the electric utility and to the customer, (ii) reasonably assures the continuation of safe and reliable electric service, (iii) will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock," to customers, (iv) is otherwise consistent with the public interest, (v) encourages peak load reduction or efficient use of the system, (v) encourages utility-scale renewable energy and storage, (vi) encourages DERs, (vii) reduces low-income energy burdens, (viii) encourages energy efficiency, (ix) encourages carbon reductions, (x) encourages beneficial electrification, including electric vehicles, (xi) supports equity in contracting, (xii) promotes resilience and security, and (ix) maintains adequate levels of reliability and customer service.

(h) Decision. - Upon receiving a PBR Application by an electric utility that incorporates PBR mechanisms as listed in (e), the Commission, after notice and an opportunity for interested parties to be heard, is authorized to issue an order within the time frames set forth in G.S. 62-134, approving or rejecting the utility's PBR Application; in addition to its order ruling on the electric utility's request to adjust base rates under G.S. 62-133. If the Commission rejects the PBR Application, it must provide an explanation of the deficiency and an opportunity for the utility to refile or for the utility and the stakeholders to collaborate to cure the identified deficiency and refile.

(i) Plan Period. - Any PBR Application approved pursuant to this section shall remain in effect for a plan period of not more than 60 months. Prior to the end of the PBR plan period, if the utility has not filed a petition for a subsequent PBR plan, the Commission shall initiate a proceeding to examine options for renewing or revising the PBR mechanisms.

(j) Review. - At any time prior to conclusion of a PBR plan period, the Commission, with good cause and upon its own motion, has the discretion to examine the reasonableness of the electric utility's rates under the plan, conduct periodic reviews with opportunities for public hearings and comments from interested parties, and initiate a proceeding to adjust rates or PIMs as necessary. In addition, nothing in a PBR proposal shall inhibit or take away from the Commission's authority to grant deferrals for extraordinary costs in between rate cases.

(k) Utility Reporting. - For purposes of measuring an electric utility's earnings under a PBR Application approved under this section, the electric utility shall make an annual filing that sets forth the electric utility's earned return on equity, the electric utility's revenue requirement trued up with the actual electric utility revenue, the amount of revenue adjustment in terms of customer refund or surcharge, and the adjustments reflecting rewards or penalties provided for in performance-based plans approved by the Commission.

(l) Nothing in this section shall be construed to (i) limit or abrogate the existing rate-making authority of the Commission or (ii) invalidate or void any rates approved by the Commission prior to the effective date of this section. In all respects, the alternative ratemaking mechanisms, designs, plans or settlements shall operate independently, and be considered separately, from riders or other cost recovery mechanisms otherwise allowed by law, unless otherwise incorporated into such plan.

(m) Commission Report. - No later than April 1 of each year, the Commission shall submit a report on the activities taken by the Commission to implement, and by electric power suppliers to comply with, the requirements of this section to the Governor, the Environmental Review Commission, and the Joint Legislative Oversight Committee on Agriculture and Natural and Economic Resources, the chairs of the Senate Appropriations Committee on Agriculture, Natural, and Economic Resources, and the chairs of the House of Representatives Appropriations Committee on Agriculture and Natural and Economic Resources. The report shall include any public comments received regarding environmental impacts (including but not limited to air, water and waste emission levels) of the implementation of the requirements of this section. In developing the report, the Commission shall consult with the Department of Environmental Quality.

SECTION 2.(b) The Commission shall adopt rules as required by G.S. 62-133A(g), as enacted by Section 2(b) of this act.

PART II. EFFECTIVE DATE

SECTION 1. Part I of this act is effective when it becomes law and applies to any rate-making mechanisms filed by an electric utility on or after the date that rules adopted pursuant to G.S. 62-133A(g), as enacted by Section 2(a) of this act, become effective.

Docket E-100, Sub 178
Exhibit 5

DUKE ENERGY

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Oct. 6, 2021

Dionne Delli-Gatti
NC Clean Energy Director

Director Delli-Gatti:

Thank you for your question regarding our understanding of key portions of the compromise energy legislation {H951) and our continuing commitment to assist our low-income customers. On behalf of Duke Energy, please see below my reply:

- Duke Energy reaffirms that H951 does not alter long-standing precedent regarding the scope of authority of the North Carolina Utilities Commission ("Commission") and that the Commission retains complete approval and supervisory authority with respect to its development of the Carbon Plan in accordance with the terms of H951. H951 does not, in any way, give Duke Energy equal footing with the Commission or veto power over Commission decisions with respect to the Carbon Plan. The legislation does not suggest, nor would Duke Energy ever assert, that Duke Energy is a co-equal of the Commission with respect to decision-making authority under the legislation.

- Duke Energy affirms its commitment to achieving the carbon reduction goals set forth in H951 according to the specified timelines. As a company, Duke Energy has publicly affirmed its commitment to reducing CO2 emissions by building a cleaner, smarter energy future and has further acknowledged that accomplishing targeted reductions will require collaboration and alignment with state policies and stakeholders. H951 provides the springboard needed for Duke Energy to continue to take direct and bold steps to reduce carbon emissions in the state, all under the oversight, guidance and approval authority of the Commission.

- In addition to our financial commitment to the Energy Neighbor Fund and Share the Warmth programs, Duke Energy is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during times of financial hardship and, in fact, proposed to the Commission to create a collaborative workshop with interested stakeholders to address the establishment of new low-income programs. As a result of such actions, the Commission ordered Duke Energy and the NC Public Staff to convene a low-income collaborative to address the affordability issue for low-income residential customers to culminate in a report and filing of recommendations within 12 months of the first collaborative meeting. The report is to include but not limited to recommendations for new programs, rate designs and funding recommendations to assist low-income customers. This low-income affordability collaborative kicked off on July 27, 2021 and has over 30 different stakeholder organizations participating. Duke Energy is committed to working with these stakeholders to develop recommendations for new programs, rate schedules, energy efficiency measures, potential funding mechanisms and other ways to assist low-income customers. Duke Energy is also committed to implementing those recommendations that the Commission deems beneficial to low-income customers.

With appreciation,

W. Kevin McLaughlin, Jr.