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December 17, 2021

VIA ELECTRONIC FILING

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments
Docket No. E-100, Sub 178

Dear Ms. Dunston:

Pursuant to the Commission's October 14, 2021 *Order Requesting Comments and Proposed Rules* and its November 24, 2021 *Order Granting Extension,* enclosed for filing in the above-referenced docket are Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments.

If you have any questions, please do not hesitate to contact me. Thank you for your assistance with this matter.

Sincerely,

Jack E. Jirak

Enclosure

cc: Parties of Record

STATE OF NORTH CAROLINA

UTILITIES COMMISSION

RALEIGH

DOCKET NO. E-100, SUB 178

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding to Implement Performance-Based Regulation of Electric Utilities	)))))))	**DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC'S REPLY COMMENTS REGARDING COMMISSION RULES TO IMPLEMENT PERFORMANCE-BASED REGULATION OF ELECTRIC UTILITIES**

NOW COME Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively, the "Companies"), by and through their legal counsel, and respectfully submit the following Reply Comments in accordance with the North Carolina Utilities Commission's ("Commission") October 14, 2021 *Order Requesting Comments and Proposed Rules* (the "PBR Rulemaking Order") and its November 24, 2021 *Order Granting Extension*.

I. INTRODUCTION

House Bill 951 ("HB 951")[1] puts North Carolina at the forefront of the clean energy transition and modernizes the regulatory framework by authorizing the use of performance-based regulation ("PBR"). HB 951's PBR provisions update the ratemaking paradigm

[1] Session Law 2021-165 (Oct. 13, 2021).

through a balanced approach that will strengthen utility performance incentives and better align the regulatory framework with customer benefits. Maintaining the balanced approach of the PBR statute in the Commission's rule is critical to achieving the broader policy goals set forth in HB 951, including maintaining the reliability, resilience, and affordability that has characterized North Carolina's energy system for decades.

Before addressing the individual components of the Public Staff and intervenors' initial comments and proposed rules,[2] these Reply Comments summarize the Companies' position on some of the main points of contention among the various parties and provide an overview of how the PBR process would unfold under the Companies' proposed rules, which are consistent with and directly follow from HB 951. It is clear from other parties' comments that there is some confusion as to how the PBR process would work, and these Reply Comments aim to clarify such areas of confusion.

Furthermore, some parties made recommendations that are inconsistent with or not supported by HB 951's PBR statute. These Reply Comments will address such recommendations and explain how the Companies' proposed rule implements HB 951's PBR framework. In addition, certain intervenor recommendations seek to impose onerous or inflexible requirements through the rules that would unnecessarily constrain the ability of the Commission to evolve PBR implementation over time as experience is gained or would impose regulatory burdens and processes without commensurate benefit to customers. In contrast, the Companies believe that, in adopting rules, the Commission

[2] In these Reply Comments, the Companies strive to address the most significant issues raised in initial comments and proposed rules. To the extent that the Companies do not address a specific intervenor, comment, or proposed rule in these Reply Comments, that should not be construed as agreement with the same.

should prioritize flexibility and efficiency in PBR implementation and ensure that PBR implementation can evolve over time as experience is gained.

Finally, the Companies engaged Pacific Economics Group ("PEG") to prepare a detailed report titled "PBR Rules for North Carolina Electric Utilities" (the "PEG Report").[3] PEG is a consulting firm that is an industry-recognized expert in the field of utility economics, and in particular, in PBR and other alternatives to traditional rate regulation.[4] PEG is also regarded as North America's foremost multiyear rate plan ("MYRP") consultant. The PEG Report provides an appraisal of the statutory framework for PBR that is set forth in HB 951 compared to traditional ratemaking as well as PBR and MYRP designs in other states and best practices – against this backdrop, PEG then evaluates the proposed rules and initial comments submitted by the parties.

II. GENERAL REPLY COMMENTS

The North Carolina General Assembly tasked the Commission with adopting rules and guidelines for implementing the HB 951's PBR statute – N.C. Gen. Stat. § 62-133.16. As noted by PEG in its report, HB 951's PBR provisions are balanced and provide substantial customer protections including statutory caps on MYRP year two and three rates, revenue decoupling for residential customers, and an ESM with a "modest" 50 basis point dead band after which all weather-normalized earnings are returned to customers.[5]

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[3] The PEG Report is attached hereto as Exhibit A.

[4] CUCA's expert, Synapse Energy Economics ("Synapse"), references PEG's work, as does the North Carolina Energy Regulatory Process. *See* Synapse Report, at 11, n. 20 (citing PEG presentation detailing benchmarking methods and guidelines); *see, e.g.,* North Carolina Energy Regulatory Process Performance Based Regulation – Study Group Work Products, PBR Regulatory Guidance: Implementation Suggestions for the NCUC From the North Carolina Energy Regulatory Process, at 22-24 (2020) ("NERP PBR Guidance," attached to NCJC et al.'s Initial Comments as Exhibit 4, and available at https://deq.nc.gov/media/17684/download).

[5] *See* PEG Report, at 5.

First, contrary to those intervenors who brand HB 951 as "pro-utility" legislation, the PBR statute is a customer-focused legislative framework that balances the utilities' need for modernized cost recovery mechanisms to address new clean energy mandates and smaller, more frequent investments (such as for grid improvements and distributed energy resource ("DER") enablement) with enhanced customer benefits to align utility performance with customer expectations. Contrary to the comments of certain intervenors, there is nothing extreme or unique about the ratemaking tools authorized by the PBR statute. Rather, the modernized ratemaking tools authorized under HB 951 simply bring North Carolina more in line with regulatory constructs around the country that have similarly evolved over time in recognition of the need for a broader array of regulatory tools. As PEG concluded from its evaluation of the statutory framework, HB 951 provides for "a thoughtful and cautious transition to PBR in North Carolina."[6]

The need for modernized ratemaking tools has been widely recognized, both across the country and in North Carolina specifically, including through the recent North Carolina Energy Regulatory Process ("NERP"), a broad stakeholder process initiated in connection with North Carolina's Clean Energy Plan. The NERP assessed modernized ratemaking tools and concluded that "PBR offers a suite of reforms that, together, can resolve limitations of [traditional cost of service] ratemaking while encouraging utilities to better serve state policy goals and customer interests."[7] Thus, the PBR provisions are not, first and foremost, "pro-utility" but instead have been designed and supported by a wide range of stakeholders in order to achieve broader policy goals established by the state (which

[6] PEG Report, at 1.
[7] NERP PBR Guidance, at 6.

requires regulatory structures that create an opportunity for a utility to finance capital investments at reasonable rates for the benefit of all customers). In fact, certain provisions of HB 951 actually increase utility risk. For instance, the Earnings Sharing Mechanism ("ESM") allows the Commission to "reach back" and require sharing of past earnings with customers, which it never has been able to do under traditional ratemaking. Moreover, as discussed in more detail below, this sharing is asymmetrical – the ESM refunds 100% of earnings in excess of 50 basis points above the authorized rate of return on equity ("ROE") (if any) on an annual basis, whereas, the utility must underearn for approximately two years before it can adjust rates through filing another rate case and has no ability to recover prior shortfalls. This narrow, asymmetrical ESM is unlike MYRPs in other states, which typically include larger ROE bands and/or only require sharing of a portion of the earnings above the band.[8] In the same vein, MYRPs from other jurisdictions are also usually based on fully forecasted test years or may be based on forecasts of capital projects with O&M escalation based on indices and inflation adjustments.[9] Since all elements are forecasted or escalated based on indices, forecasted billing determinants are also used in establishing rates to more accurately match revenues with costs, all of which reduce risk for the utility.[10] These MYRP elements adopted by other states contrast with the North Carolina PBR statute, which does not include comprehensive forecasts and escalations, but instead only includes increases for forecasts of costs related to certain capital investment projects, net of operating benefits. The Companies provide this context and highlight these examples of increased utility risk to counter intervenors who mischaracterize HB 951 as "utility-

[8] *See* PEG Report, at 5.
[9] *See id*. at 5, 17.
[10] *See id*.

friendly" in order to argue that the Commission needs to somehow balance out that legislation by adopting onerous or restrictive rules. PEG confirms this viewpoint, explaining in its report that the statutory framework "has an unusually extensive array of customer protections."[11]

Second, despite attempts by several intervenors to argue otherwise, HB 951 does not empower the Commission to effectively legislate what intervenors perceive as missed opportunities or policy shortcomings in HB 951. As discussed more fully below, the Commission should reject requests that effectively override the PBR statute (a product of overwhelming bipartisan consensus), contradict the policy framework established by the General Assembly, or go beyond the actions authorized under HB 951 – such requests disregard the plain language and legislative intent of HB 951 and would exceed the Commission's authority.[12]

For example, contrary to what some intervenors have argued:

- The North Carolina PBR statute does NOT provide for fully forecasted test years for Rate Years 1, 2, and 3 – instead, base rates will reflect only Commission-authorized incremental capital spending projects and associated "step-ups" in revenue requirements each year of the MYRP;

[11] *See id*. at 2, 5.

[12] The Commission is a creation of the legislature and has no authority except that given to it by statute. *State ex rel. Utils. Comm'n v. Edmisten*, 291 N.C. 451, 464, 232 S.E.2d 184, 192 (1977); *State ex rel. Utils. Comm'n v. State*, 243 N.C. 12, 16, 89 S.E.2d 727, 730 (1955) ("The Utilities Commission is not a policy-making agency of the State. That prerogative rests in the General Assembly."); *see also, Order Granting Application in Part, with Conditions, and Denying Application in Part*, Docket No. E-2, Sub 1089 (March 28, 2016), at 41 ("Entities and parties dissatisfied by these processes and procedures had opportunity to address provisions of the Mountain Energy Act while the General Assembly deliberated over its provisions. To the extent they failed to do so, efforts to persuade this Commission to disregard the dictates of the Mountain Energy Act are too late and out of place.").

- The North Carolina PBR statute does NOT allow for comprehensive true-ups each year of the MYRP – instead, there are only three statutorily-permitted annual rate adjustments relating to (1) the ESM, (2) decoupling, and (3) performance incentive mechanisms ("PIMs");
- HB 951 does NOT require approval of a Carbon Plan prior to filing a PBR application – instead, the legislation dictates the schedule for PBR rulemaking and provides that a utility can file a notice of intent to file a PBR application once the Commission rules implemented in this docket are effective (February 10, 2022);
- The North Carolina PBR statute does NOT allow the Commission to require utilities to stagger their PBR filings or file in designated years – rather, a utility may file after giving appropriate notice of its intent to file a PBR application to trigger the process whereby the Commission must initiate a technical conference process within 60 days;
- The North Carolina PBR statute does NOT contemplate multiple proceedings in multiple dockets to determine policy goals and capital spending projects in advance of PBR filings, which would inhibit greater administrative efficiency – rather, these determinations are to be made by the Commission in the general rate case proceeding evaluating a PBR application;
- The North Carolina PBR statute does NOT contemplate a cure process that is a complete re-do of the initial PBR application or a full blown rate case that restarts the 300-day clock – instead, the cure process is meant to be a

targeted and limited opportunity for a utility to work with stakeholders to fix specific Commission-identified deficiencies;

- The North Carolina PBR does NOT create a heightened or different burden of proof for a utility filing a PBR application – the case law is well-established for the burden of proof in rate cases, and the PBR statute does not somehow alter that burden.

Simply put, this rulemaking proceeding is not a vehicle for rewriting HB 951 to add requirements that the legislation does not include or alter those it does include.

Third, and as was briefly described above, each rate year under the MYRP does not require a fully forecasted test year with comprehensive true-ups, but rather is limited to capital project "step-ups" in base rates and three specific riders. While some states employ MYRP mechanisms which involve fully forecasted test years, comprehensive cost trackers, symmetrical true-ups of revenue to actual costs, and/or formula rates, North Carolina's PBR statute is more limited in scope and prescriptive in nature. N.C. Gen. Stat. § 62-133.16 specifies what forecasted costs receive rate recognition during the MYRP – step-ups in rates are based on projected revenue requirements for a specific set of capital projects, which the Commission evaluates and authorizes as part of a PBR rate case. N.C. Gen. Stat. § 62-133.16 also specifies how rates should be adjusted via a rider established by the Commission for decoupling, ESM, and PIMs – no true-ups are contemplated. All other items (O&M fluctuations unrelated to MYRP projects, inflation, any capital projects that were not included in the MYRP, project cancellations, etc.) are subject to regulatory lag and therefore must be managed by the utility during the MYRP. While the utility remains at risk for underearning, customers are protected from utility overearning by the asymmetrical narrow earnings band provided by the ESM. In addition, the Commission or Public Staff can initiate a proceeding at any time during the MYRP if they are concerned that rates are no longer just and reasonable.

Fourth, adding entirely separate and lengthy processes to address PBR issues on a piecemeal basis inhibits administrative efficiency, is not supported by HB 951, and could ultimately interfere with achievement of the policy goals established by HB 951. N.C. Gen. Stat. § 62-133.16 establishes a framework through which the Commission can consider policy goals and PIMs, capital spending project proposals and costs, and all other related matters in a single proceeding deciding a PBR application. N.C. Gen. Stat. § 62-133.16 establishes a clear timeline for the PBR application submittal and review process, along with a specific timeline for certain pre-application activities. There is no basis in N.C. Gen. Stat. § 62-133.16 to support the argument that numerous separate, lengthy proceedings are required, particularly where such separate, lengthy proceedings would substantially delay and, in some cases, prevent the effectuation of the policy goals and related customer benefits sought to be achieved through PBR. More practically, the statute itself establishes initial policy goals and only requires that one PIM be included in a utility MYRP. As such, a separate docket to consider policy goals and PIMs in advance of a PBR filing is unnecessary and would only result in delay, wasted resources, and needless complexity. Likewise, capital spending projects and their associated revenue requirements are most effectively evaluated in the context of a rate case, not a separate proceeding. The NERP recognized that PBR is intended to result in a reduction of "costly administrative burden"[13] and that one of the guiding outcomes of PBR regulatory reform should be "administrative efficiency."[14] In contrast, the multiplication of PBR-related proceedings recommended by a number of intervenors (all of which have no basis in the PBR statute) would achieve the opposite outcome and would burden the Commission, the Companies, and intervenors with a nearly non-stop cycle of PBR-related proceedings. The PEG Report similarly concluded that many of the additional requirements and proceedings proposed by intervenors "would offer limited value and could significantly reduce the regulatory efficiency of MYRPs or even make MYRPs less efficient than current regulation."[15] As the Companies emphasized in their Initial Comments, the PBR rules adopted by the Commission should facilitate an efficient and effective PBR process, not result in a multitude of unnecessary regulatory proceedings that could ultimately serve as a barrier to achieving the policy objectives in the statute.

Fifth, the rules implementing PBR should be broad and general enough to provide for flexibility during implementation, particularly where it is reasonable to assume that the Commission, the Companies, and intervenors will need to evolve and improve the PBR regulatory process as lessons are learned through actual implementation. Stated differently, it would be inappropriate and unnecessary to hard code overly rigid processes and schedules into the Commission's rules before the Commission has had the opportunity to gain experience reviewing and overseeing an actual PBR application. Many of the intervenors' proposals are inflexible and overly prescriptive. In some cases, the Companies

[13] NERP PBR Guidance, at 6.
[14] North Carolina Energy Regulatory Process – Summary Report and Compilation of Outputs (2020), at 13 (available at https://deq nc.gov/media/17727/download).
[15] PEG Report, at 2.

do not necessarily disagree with the recommendation in principle – but nevertheless, believe it would be inappropriate to formalize such requirements in a rule. Of course, the Commission's rules should provide clear guidance and filing requirements for a PBR application, but the rules should provide enough flexibility to allow the Commission and the parties the leeway to leverage lessons learned in an efficient manner. The Companies' proposed rule strikes the right balance.

Along the same lines, several intervenors imply that PIMs should be set in stone by the Commission in advance and propose rules that lock in detailed guidelines for policy goals and PIMs outside of what is in the statute. The Companies believe it would be appropriate to a take a measured and thoughtful approach toward establishing PIMs during the first PBR rate cases. A measured and thoughtful approach is important as utilities, interested stakeholders, and this Commission gain experience and obtain information on best practices for tracking information. In addition to PIMs, the PBR statute allows for a utility to propose tracking metrics (for quantitatively measuring and monitoring outcomes and/or utility performance) that are not tied to financial incentives or rewards.[16] These tracking metrics will provide useful information in evaluating future PIMs. This deliberate approach is essential as utilities and stakeholders tackle novel issues, gain experience with new legislative and regulatory tools, and implement lessons learned. It also allows the Commission and utilities to adapt as policy goals and objectives change over time.[17] As PEG points out in its report, in many jurisdictions, first generation MYRPs take the form of cautious steps away from traditional ratemaking. One reason is that many parties to

[16] *See* N.C. Gen. Stat. § 62-133.16(c): "[t]he PBR application may also include proposed tracking metrics with or without targets or benchmarks to measure electric public utility achievement."
[17] NERP PBR Guidance, at 20.

regulation are, at least initially, reluctant to see a utility's revenue differ very much from its cost of service. Nevertheless, plan designs can evolve as the parties gain experience. As PEG succinctly put it, "North Carolina is under no obligation to be in the vanguard of regulatory reform."[18]

Sixth, the base rates in effect during Year 3 of the MYRP should remain in effect following the expiration of a PBR plan. Base rates should not be reset or reduced after Year 3 of a MYRP, as some intervenors urge, as this would be punitive to utilities and place them in a worse position than when they originally filed the rate case to approve a MYRP – and immediately necessitate a new rate case filing. Intervenors' recommendations in this respect are unsupported by N.C. Gen. Stat. § 62-133.16 and would effectively automatically deny rate recovery for capital investments that have been thoroughly reviewed and approved by the Commission and found to be reasonable and prudent. Neither the Companies nor PEG have identified a single state in the country in which base rates are adjusted to deny rate recovery of approved prudent and reasonable investments. The Companies' proposed rule is fair to both customers and the utility by continuing Year 3 base rates, but also continuing the ESM (a customer protection) and decoupling adjustments.

Finally, several intervenors seemed confused by the intersection of demand-side management ("DSM")/energy efficiency ("EE") and PIMs. The statute states: "[a]ny incentives related to demand-side management and energy efficiency measures pursuant to G.S. 62-133.9(f) shall be excluded from the [limit prohibiting the total of PIM

[18] *See* PEG Report, at 8.

incentives/penalties from exceeding 1% of the utilities total annual revenue requirement under G.S. 62-133] and shall continue to be recovered through the demand-side management and energy efficiency (DSM/EE) rider." N.C. Gen. Stat. § 62-133.16(c)(4). The intent of this section is to clarify that DSM/EE cost recovery and incentives are separate from the PBR process and that utilities are not permitted double recovery of incentives related to DSM/EE programs through both the DSM/EE rider and through the PBR PIMs adjustment. The Companies' proposed rules accomplish both of these objectives.

III. PBR RATE CASE UNDER THE COMPANIES' PROPOSED RULE

The following provides a brief overview of the PBR application and review process under the Companies' proposed rules. The Companies have also prepared a timeline showing this process, which is attached hereto as Exhibit B.

A. Pre-Filing

At least 60 days in advance of filing a PBR application, an electric utility starts the process by submitting a letter of intent to file a PBR application and a request for the Commission to initiate a pre-filing technical conference.[19] Upon receiving the utility's request, the Commission initiates a pre-filing technical conference process which will consist of one or more public meetings at which the utility will present information

[19] The Public Staff's position is that the request to initiate a technical conference should be filed 90 days in advance of a utility's notice of intent to file a general rate case that includes a PBR application. *See* Public Staff Proposed Rule R8-__(d)(1). The Companies do not object to filing the request for a technical conference 90 days in advance of their notice of intent to file a PBR application, but note that regardless of when the request to initiate the technical conference is filed, the duration of the technical conference process is limited to 60 days by statute. *See* N.C. Gen. Stat. § 62-133.16(j)(3).

regarding projected transmission and distribution ("T&D") capital expenditures expected to be included in its PBR application.

At the technical conference, the utility will present a project description, project justification, estimated cost, and estimated in-service date for each planned incremental T&D capital project to be included in the PBR application.[20] Interested parties are permitted to provide comment and feedback at the technical conference, but no pre-filed testimony, written discovery, oral argument, or cross-examination will be permitted. In other words, the technical conference is not an evidentiary hearing, but rather a pre-filing opportunity for the Commission and other parties to learn about the incremental T&D projects the utility plans to include in its forthcoming PBR application, as well as an opportunity for the utility to hear reactions from Commissioners and other parties that may shape the T&D projects the utility ultimately decides to include in its filing. The technical conference process is to be completed within 60 days from the date the utility requests initiation of such process.

Aside from the letter of intent and pre-filing technical conference, there are no other pre-filing requirements or proceedings.

B. PBR Application Filing

The PBR application is required to include a Decoupling Ratemaking Mechanism, one or more PIMs, and a MYRP, including an ESM and proposed revenue requirements and base rates for each of the rate years of the MYRP.

[20] The Public Staff has asked the Companies to provide technical conference materials to participants ten business days prior to the technical conference. The Companies have no objection to this request.

With respect to the Decoupling Ratemaking Mechanism, the utility shall include the proposed revenue requirement per residential customer for each year of the MYRP. To the extent that net lost revenues are collected through the utility's DSM/EE rider, the utility must include a plan to ensure that that there is no double collection of net lost revenues through the DSM/EE rider and the Decoupling Ratemaking Mechanism. The utility must also file the rate schedule for the Annual Decoupling Rider for Rate Year 1 (initially set at $0 in the first PBR application) and a template showing the calculation for annual adjustment to the rider.

With respect to PIMs, the utility shall include at least one proposed PIM, including the Policy Goal[21] targeted by the PIM, the method of measuring performance, and calculation of incentive and/or penalty. The PIMs proposed by the utility must include one or more of the following: (1) rewards based on the sharing of savings achieved by meeting or exceeding a specific Policy Goal; (2) rewards or penalties based on differentiated authorized rates of return on common equity to encourage utility investments or operational changes to meet a specific Policy Goal (which shall not be greater than 25 basis points); and/or (3) fixed financial rewards to encourage achievement of specific Policy Goals, or fixed financial penalties for failure to achieve Policy Goals. The PBR application may also include proposed Tracking Metrics[22] with or without targets or benchmarks to measure

[21] "Policy Goal(s)" means the expected or anticipated achievement of operational efficiency, cost-savings, or reliability of electric service that is greater than that which already is required by State or federal law or regulation, including standards the Commission has established by order prior to and independent of a PBR application, provided that, with respect to environmental standards, the Commission may not approve a Policy Goal that is more stringent than is established by (i) State law, (ii) federal law, (iii) the Environmental Management Commission pursuant to G.S. 143B-282, or (iv) the United States Environmental Protection Agency. N.C. Gen. Stat. § 62-133.16(a)(8).
[22] "Tracking Metric(s)" means a methodology for tracking and quantitatively measuring and monitoring outcomes or electric public utility performance. *Id*. at (a)(10).

utility performance. The filing shall include the rate schedule for the Annual PIM Rider for Rate Year 1 (initially set at $0 in the first PBR application) and a template showing the calculation for annual adjustment to the rider, including how amounts will be allocated to the customer classes.

In its proposed MYRP, the utility includes descriptions of the forecasted capital spending projects included in the MYRP and a calculation of revenue requirements associated with the forecasted capital spending projects for each rate year of the MYRP. The MYRP filing also includes calculations of the proposed percent increases (or "step-ups") for Rate Years 2 and 3 of the MYRP, proposed allocation of the revenue requirements to the customer classes, and the proposed rate schedules for each rate year. The filing must also include the rate schedule for the Annual ESM Rider for Rate Year 1 (initially set at $0 in the first PBR application) and a template showing the calculation for annual adjustments to the rider, including how amounts will be allocated to the customer classes and any pro forma adjustments that the utility proposes to make to the financial results used in the ESM in addition to those specified in the statute.

PIMs (and the associated Policy Goals) and forecasted capital spending projects (and the associated revenue requirements) are filed, evaluated, and approved as part of the PBR rate case proceeding.

C. Criteria for Evaluating a PBR Application

The Commission shall consider whether the PBR application: (i) assures that no customer or class of customers is unreasonably harmed and that the rates are fair both to the utility and to the customer; (ii) reasonably assures the continuation of safe and reliable electric service; and (iii) will not unreasonably prejudice any class of electric customers and result in sudden substantial rate increases or "rate shock" to customers.

The Commission may also consider whether the application: (i) encourages peak load reduction or efficient use of the system; (ii) encourages utility-scale renewable energy and storage; (iii) encourages DERs; (iv) reduces low-income energy burdens; (v) encourages EE; (vi) encourages carbon reductions; (vii) encourages beneficial electrification, including electric vehicles; (viii) supports equity in contracting; (ix) promotes resilience and security of the electric grid; (x) maintains adequate levels of reliability and customer service; or (xi) promotes rate designs that yield peak load reduction or beneficial load-shaping.

D. Order Approving PBR Application

In its order approving the PBR application, the Commission establishes base rates under N.C. Gen. Stat. § 62-133 and also approves the utility's incremental capital spending projects and associated revenue requirements for Rate Years 1, 2 and 3. The Commission also approves the templates to be used to calculate the annual adjustments pursuant to the Annual Decoupling Rider, the Annual ESM Rider, and the Annual PIM Rider. The Commission's order also establishes an annual revenue requirement per residential customer for each rate year and an appropriate distribution of that revenue requirement per customer in each month of the year. The approved monthly revenue requirements times the actual number of residential customers each month becomes the target revenue for the residential class for purposes of the Decoupling Ratemaking Mechanism.

E. Rate Years

The approved PBR application shall remain in effect for a period of 36 months, consisting of three "Rate Years." The base rates in each year include the base rates approved pursuant N.C. Gen. Stat. § 62-133 plus the approved revenue requirement for the forecasted capital spending projects.

- Rate Year 1 begins on the rate effective date and includes the base rates approved pursuant to N.C. Gen. Stat. § 62-133, plus the approved revenue requirement for Year 1 forecasted capital spending projects (collectively, "Year 1 Base Rates");
- Rate Year 2 begins 12 months later and consists of Year 1 Base Rates, plus the revenue requirement or "step-up" associated with approved Year 2 capital spending projects (collectively, "Year 2 Base Rates");
- Rate Year 3 begins 12 months later and consists of Year 2 Base Rates, plus the revenue requirement step-up associated with approved Year 3 capital spending projects (collectively, "Year 3 Base Rates").

F. Annual Riders and Reporting

In addition to the capital project step-ups each rate year authorized by the Commission in its order, rates are adjusted during the MYRP pursuant to three riders: the Annual Decoupling Rider, the Annual PIM Rider, and the Annual ESM Rider (collectively, the "Annual PBR Review Riders").

1. Annual Decoupling Rider

The purpose of the Annual Decoupling Verification is to determine the amount of distributions or collections necessary under the Decoupling Ratemaking Mechanism. Each month, the utility defers to a regulatory asset or liability account the difference between the actual revenue and the target revenue for the residential class. The regulatory asset or liability accrues a return at the utility's last authorized weighted average cost of capital ("WACC"). The utility is required to file quarterly reports with the Commission on the status of the decoupling regulatory asset or liability. Adjustments to the Annual Decoupling Rider are designed to collect or distribute the amount in the regulatory asset or liability over a 12-month period.

The process for the Annual Decoupling Verification is as follows:

- Within 45 days of the conclusion of each quarter of the MYRP, the utility shall file a quarterly status report for the Decoupling Ratemaking Mechanism;
- Within 45 days following the conclusion of each rate year, the utility shall file its calculation of the adjustment to the Annual Decoupling Rider per the template approved by the Commission;
- The Public Staff shall verify the calculation, and the Commission will issue an order establishing the adjustments; and
- The new rider rates shall be effective 60 days following the conclusion of each rate year.

2. Annual ESM Rider and Annual PIM Rider

The Annual ESM and PIMs Review is the annual proceeding to determine the amount, if any, of sharing necessary under the ESM, and distributions or collections necessary under the PIMs.

With respect to the Annual ESM Rider, the Commission examines the earnings of the utility during the rate year to determine if the earnings exceeded the authorized ROE determined by the Commission in the proceeding establishing the PBR. If the adjusted earnings exceed the authorized ROE plus 50 basis points, the excess earnings above the authorized ROE plus 50 basis points will be flowed back to customers in the Annual ESM Rider established by the Commission.[23] Any penalties or rewards from PIMs incentives and any incentives related to DSM and EE measures are excluded from the determination of any sharing pursuant to the ESM. If the Commission determines an amount to be flowed back to customers pursuant to the ESM, the utility shall establish a regulatory liability.[24] The Annual ESM Rider is designed to distribute the sharing amount over a 12-month period, including a return on the regulatory liability at the utility's last authorized WACC.

With respect to the Annual PIM Rider, the Commission evaluates the performance of the utility with respect to Commission-approved PIMs applicable in the rate year. Any financial rewards shall be collected from customers and any penalties distributed to customers, in each case, through the Annual PIM Rider established by the Commission. The Annual PIM Rider is designed to distribute or collect the penalties or rewards over a 12-month period. No return shall accrue on the rewards or penalties.

The process for the Annual ESM and PIMs Review is as follows:

- Within 60 days following the conclusion of each rate year, the Commission shall initiate an Annual ESM and PIMs Review proceeding;

[23] If the adjusted earnings fall below the authorized ROE, the utility's only remedy is to file a rate case pursuant to N.C. Gen. Stat. § 62-133.
[24] The utility may establish the regulatory liability sooner with an estimate if required by accounting guidance.

- Within 90 days following the conclusion of each rate year, the utility shall file an Annual ESM and PIMs Review Report;[25]
- The Public Staff shall review the Annual ESM and PIMs Review Report and, within 60 days of submission of the filing by the utility, shall submit a report to the Commission describing its findings and any recommendations emanating from the review;
- The utility shall have 30 days to file a reply to the Public Staff's report;
- The Commission shall issue an order establishing the adjustments to the Annual ESM and PIMs Riders within 270 days following the conclusion of each rate year, and the adjustments shall be effective no more than one year after the conclusion of the rate year being reviewed with rates set to recover or distribute approved rider amounts over a 12-month period.

The pre-approved revenue requirement step-ups relating to Commission-authorized capital spending projects and the three Annual PBR Review Riders described above are the only rate adjustments that occur during the MYRP. There is no comprehensive true-up to reflect changes in costs relating to capital spending projects, O&M not related to MYRP projects, inflation, to adjust for underearning, or to account for any other variations occurring during the PBR plan.

G. Review of PBR Rates After Approval

[25] This Report will include (1) the utility's earned ROE, for actual results during the applicable rate year, including a weather normalization adjustment, an adjustment to remove any penalties or rewards from PIMs incentives and any incentives related to DSM/EE measures, and any other pro forma adjustments approved by the Commission in its order approving the PBR application; (2) a schedule showing the calculation of any sharing amounts due under the Annual ESM Rider; and (3) a schedule showing the calculation of any rewards or penalties provided for in PIMs approved by the Commission to be included in the Annual PIM Rider.

Nevertheless, at any time prior to expiration of the 36-month period, the Commission, with good cause and upon its own motion or petition by the Public Staff, may examine the reasonableness of the utility's rates under the MYRP, conduct periodic reviews with opportunities for public hearings and comments from interested parties, and initiate a proceeding to adjust base rates or PIMs as necessary. If the Commission initiates such a proceeding, the utility has the right to respond and file testimony and exhibits to address the reasonableness of its rates under an approved plan. No adjustments to the base rates or PIMs will be made unless the Commission finds after notice and hearing that the current rates or PIMs under a plan are not just and reasonable and not in the public interest.

H. Deferrals

The approval of a PBR application does not limit the Commission's authority to grant additional deferrals between rate cases for extraordinary costs not otherwise recognized in rates. In addition, if the utility forecasts that any single new generation plant with a total plant in service balance in excess of $500 million will be placed into service during the term of the MYRP, such plant shall not be included in a MYRP, but instead the utility may, either as part of the PBR application or separately, request a deferral accounting order for such plant.

Should the Commission fail to approve, modify, or reject the electric public utility's PBR application prior to end of the 300-day suspension period allowed under N.C. Gen. Stat. § 62-133.16, and the utility elects not to implement the requested rates prior to the Commission issuing an order, the Commission shall authorize deferred accounting or such other mechanism that will allow the utility to recover revenue shortfalls resulting from such delay, including carrying costs at the utility's last authorized WACC.

I. Procedure Upon Commission Rejection of a PBR Application

In the event that the Commission rejects a PBR application, the Commission is to provide a detailed explanation of the deficiency in its order ruling on the PBR application. The Commission shall provide the utility with a period of no more than 90 days to file a proposed cure to the identified deficiency, or to collaborate with stakeholders and file a proposed cure to the identified deficiency.

In the event that the Commission rejects a PBR application, the Commission shall nevertheless establish base rates in accordance with N.C. Gen. Stat. § 62-133 based on the PBR application. If the electric public utility files a proposed cure to the deficiency, the Commission shall issue an order approving or rejecting the PBR application with the proposed cure within 60 days.

J. Conclusion of MYRP

If the utility does not file a general rate case or successor PBR application to become effective after the final rate year, any approved PIMs shall expire but the Year 3 Base Rates, as well as the ESM and Decoupling Ratemaking Mechanism effective for the final rate year, will continue until the effective date of Commission-approved base rates from a subsequent general rate case. The utility shall continue to file an Annual ESM and PIMs Review Report for each 12-month period beyond the end of the last rate year of the PBR plan for the ESM and continue to file annual adjustments to the Decoupling Ratemaking Mechanism.

IV. THE COMPANIES' RESPONSE TO THE PUBLIC STAFF AND INTERVENORS' INITIAL COMMENTS AND PROPOSED RULES

A. Public Staff

The Public Staff's proposed rule aligns with the Companies' proposed rule in several important ways. For example, the Companies and the Public Staff agree that at the conclusion of the 36-month plan period, rates do not "revert back" to pre-MYRP base rates, but rather continue at Year 3 Rates.[26] In addition, under both proposed rules, forecasted capital spending projects for future rate years are evaluated in the context of an individual utility's PBR rate case – not in a separate proceeding.[27] Like the Companies, the Public Staff also does not attempt to set predetermined policy goals or PIMs in its proposed rule beyond what is in the statutory language. That said, there are also several areas of disagreement between the Companies and the Public Staff.

One area of disagreement with Public Staff relates to the outcome in the event that, after Commission approval of PBR (including a MYRP), the utility prudently and reasonably cancels or delays a projected capital spending project that had been authorized by the Commission as part of its PBR decision. The Public Staff's proposed rule establishes procedures for cancelling or delaying previously authorized capital spending projects which are far beyond the scope of N.C. Gen. Stat. § 62-133.16.[28] In essence, under the Public Staff's proposal, a utility would be required to refund revenues it has already collected pursuant to rates approved by the Commission and then adjust its rates going forward outside of a rate case and apart from any of the rate adjustments that are actually permitted by the statute, even if the utility has actually under-earned in that same period.

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[26] The Companies' proposed rule regarding post-plan period rates differs from the Public Staff's in that the Companies' rule includes a continuation of the Decoupling Rider and ESM Rider, which benefits customers. Nevertheless, both the Public Staff and the Companies recommend that base rates remain at Year 3 levels at the conclusion of the MYRP. *See* DEC/DEP Proposed Rule R1-17(m)(10)(g.); *see also,* the Public Staff's proposed Rule R8-__(m).
[27] *See* DEC/DEP Proposed Rule R1-17(m)(5)(c.); *see also,* Public Staff Proposed Rule R8-__(e)(2).
[28] *See* Public Staff Proposed Rule R8-__(i), titled "Cancelation or Postponement of Capital Spending Projects; No Substitution."

More specifically, the Public Staff's proposed rule provides that a utility must notify the Commission of cancellation or postponement within 30 days and submit a corresponding rate adjustment proposal to include a refund of all recovered project costs and proposed rate changes for future years of the MYRP. Furthermore, if a utility makes "some other material change to Capital Spending Project, it must file a status report within 30 days of the known change, including the reason for the change, any changes to the projected costs, scope, or timing of the project."[29] The Public Staff's proposed rule also provides that a utility shall not substitute one or more capital spending project(s) for an already Commission-approved capital spending project without Commission approval.

The Companies oppose this process for several reasons, including that it limits utility operational and managerial flexibility and discretion; prevents real-time, on-the-ground prudent and reasonable utility decision-making regarding project postponement or cancellation; creates unintended consequences that weaken utility incentives to improve performance and take initiatives that yield results; creates more administrative burden and lessens regulatory efficiency; and, perhaps most importantly, contradicts the plain language of HB 951 by adding a rate adjustment – in effect, an asymmetrical true-up for cancellation costs – that is not permitted by the statute.

The proposed procedures encroach on utility operations and project management decisions. There is no evidence that, through the enactment of HB 951, the General Assembly intended to convert the Commission into utility managers or operators. As has been well-established under North Carolina law, the utility bears the obligation to provide

[29] *Id.*

reliability and, as a result, it is necessary that the utility maintain discretion regarding the investment decisions required to ensure continued reliability in the most prudent and reasonable manner, in all cases subject to future prudence review by the Commission.[30] Any number of prudent and valid reasons could support project postponement or cancellation, and in fact, regulators could find that a utility acted imprudently or unreasonably by keeping a project alive longer and failing to postpone or cancel sooner under certain circumstances.

For example, suppose a utility filed a PBR rate case in 2023, with a rate effective date of January 1, 2024, and the MYRP includes a capital spending project in Rate Year 3 (2026) that leverages a certain type of technology. In the interim – between when the project was approved in the rate case (2023) and when the project is expected to go into service (2026) – the technology becomes obsolete, and it does not make sense to continue with the capital spending project in the form in which it was authorized by the Commission. Under the Public Staff's approach, the Companies would not be permitted to substitute another project that would benefit customers and solve the same problem that the obsolete technology no longer can address, so it would either have to (a) cancel the project and submit a refund to customers; or (b) continue with a project that it is no longer beneficial to customers.

[30] *See e.g., Order Holding Docket in Abeyance*, Docket No. E-100, Sub 122 (Aug. 11, 2009), at 28 ("*At the end of the day, however, it is the utilities' responsibility to balance the sometimes complex and competing issues so that their customers are assured a reliable electricity supply at reasonable cost.*"); *see also Order Denying Motion for Evidentiary Hearing*, Docket No. E-7, Sub 790 (Jan. 17, 2017), at 3; *State ex rel. Utils. Comm'n v. Gen. Tel. Co. of Southeast*. 281 N.C. 318, 189 S.E.2nd 705 (1972) (utility is free to manage its property and business as it sees fit).

The PBR statute contemplates that rate recognition will be granted in Rate Year 1 to "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" and in Rate Years 2 and 3 to "projected incremental Commission-authorized capital investments." In a PBR proceeding, the Commission will undoubtedly closely review the projected capital investments in Rate Years 1 – 3 and only approve those capital investments that it finds are in the public interest. And the Companies expect that in the vast majority of circumstances, the actual investments will largely track the projected investments. But it is simply unreasonable to assume that across a three-year period, there will not be circumstances that arise in which it would be prudent and reasonable for the utility to modify or delay certain investment decisions, nor would it be appropriate to approve a PBR rule structure that limits the ability of or disincentivizes the utility to bring its technical expertise to bear in real time on its system. Any alleged ability of the Companies to "game" the process for their financial benefit is purely speculative, cannot be reconciled with the Companies' obligation to ensure reliability, and is nearly entirely mitigated by the ESM, as discussed below. The Companies expect that changes from the approved projected capital investments will be narrow, targeted, and in the best interests of customers. The nebulous concern that the utility will obtain approval of a projected capital investments through the detailed and thorough PBR review process and then radically depart from those approved investment strategies is wholly unrealistic, particularly given the Commission's ongoing ability to monitor utility performance. In summary, stated simply, once the Commission has approved a PBR based, in part, on a set of projected capital investments, the Companies will diligently and prudently seek to implement such capital investments but should have the discretion to modify or cancel projects where in the public interest and such decisions should not be micromanaged through the regulatory process.

Moreover, the Public Staff's proposal is completely one-sided. As PEG points out in its report, projects often are installed a little before or after their anticipated in-service dates. It would be unfair to penalize a utility for short delays while providing no offset for projects that are placed in-service earlier than anticipated. A similar concern arises if utilities must credit customers for any incremental project costs that are lower than forecasted, while absorbing any project costs that are greater than forecasted. The integrity of a capital budgeting process should be assessed based on its overall reasonableness, not the utility's ability to project each in-service date and investment cost for particular investments with 100 percent accuracy.[31] As discussed below, true-ups of this sort are not permitted by the statute – and certainly not in the asymmetrical fashion recommended by the Public Staff.

If potential overearning is the primary concern regarding allowing the utility discretion to manage investments during the MYRP, HB 951 includes other safeguards and consumer protections that sufficiently protect customers. In particular, the ESM would flow back earnings in excess of 50 basis points above the allowed ROE. If a utility cancelled a project, and as a result spends less on capital projects than it is collecting through the approved revenue requirements relating to that project, customers would be

[31] PEG Report, at 11.

reimbursed to the extent that the underspending leads to overearning in excess of 50 basis points.

Most importantly, the General Assembly provided no statutory basis for the Public Staff's proposed refunds for project cancellations or postponement. HB 951 establishes three statutorily-permitted annual rate adjustments relating to ESM, decoupling and PIMs – a true-up flowing back refunds to customers for cancelled or postponed projects is not one of them. Under the Public Staff's approach, such a true-up would be unfairly asymmetrical in that it would only apply if the utility spends less than what it forecasted (and would be a refund to customers); if costs of the authorized capital spending projects unexpectedly increase for reasons that are not due to any imprudence on the part of the utility, the utility would not be allowed to true-up those costs and recover more from customers. The Public Staff cannot have it both ways. If the scope of what is being trued up is broadening, the utility would ask that increases in the MYRP project costs as well as increases in O&M unrelated to the MYRP projects and other projected cost increases be included. Then, the mechanism would function more like a formula rate, a mechanism that is used in several states for retail ratemaking.[32] The Companies do not recommend this approach nor is it permitted by the PBR statute, but instead urge the Commission to reject the Public Staff's proposed rules requiring Commission approval and utility refunds for cancellations, as such a mechanism is not authorized by the PBR statute.

[32] PEG notes that this quest for precision, even if implemented equitably, could ultimately devolve into a capital tracker for approved projects. *See* PEG Report, at 11. If the North Carolina legislature wanted to grant the Commission that authority to implement formula rates or capital trackers, it would have expressly done so – it did not.

An alternative and more reasonable approach to addressing cancelled or postponed projects is to require the utility to file an annual reconciliation report of actual projects placed in service during a Rate Year compared to the projected amounts approved in the rate case. The utility could explain any variances and cancelled or postponed projects. If the Commission or the Public Staff, after reviewing the reconciliation report, believes that the current rates should be adjusted, either could initiate a proceeding to adjust rates pursuant to N.C. Gen. Stat. § 62-133.16(e). This approach would allow the utility to efficiently and prudently manage its operations while preserving the Commission and Public Staff's ability to ensure that rates are just and reasonable.

Another area of disagreement with the Public Staff involves the reporting requirements included in its proposed rule. The Public Staff recommends that utilities submit filings covering each three-month period within the MYRP period.[33] The first filing would be required no later than 45 days after the first three-month period, and subsequent reports would be required every three-months.[34] The Companies have three concerns with the Public Staff's recommendation. The first concern relates to the 45-day requirement. The Companies currently provide much of the information proposed by the Public Staff in their quarterly Earnings Surveillance (E.S.-1) reports. These reports are filed 60 days after end of the quarter. The Companies believe 60 days is a more reasonable deadline, and consistent with other similar filings. The second concern is that since much of the data in the filing requirements that the Public Staff recommends is already provided in the E.S.-1

[33] *See* Public Staff Proposed Rule R8-__(k).
[34] *Id*.

reports, the requirements would be duplicative and inefficient.[35] The third concern is the proposed requirement to file much of the information – operating expenses and rate base items – at the rate class and rate schedule level. The Companies currently provide information by rate class annually in their annual cost of service ("COS") studies. These COS studies are extremely time consuming, taking four to five months to prepare. DEP files its annual COS study four months after the end of the calendar year and DEC files its annual COS study five months after the end of the calendar year. It would be infeasible to produce such a study within 45 days of the end of a quarter and extremely burdensome and unnecessary to produce it every quarter. There is nothing in the annual review process that would require this information by class. Even in a full rate case, the utility does not allocate individual capital projects to customer classes as the Public Staff is proposing in the construction status report.

The Companies and the Public Staff also disagree as to certain annual PBR review standards and filing requirements. The Companies believe that such standards and requirements should not unduly burden utilities, achieve an appropriate balance of oversight and regulatory efficiency, minimize unnecessary regulatory processes without commensurate benefits, or go beyond what is permitted in the statute. For example, the Public Staff's proposed rule regarding the ESM adjustment is as follows:

> For purposes of determining whether and to what extent an electric public utility's actual or pro forma earned return on equity falls below the low-end range or exceeds the high-end range of the authorized return band that is approved by the Commission, the only capital cost and expense increases considered, unless the Commission explicitly allows

[35] The Companies do not think that the Public Staff filing requirements should be adopted by the Commission; however, to the extent the Commission does adopt these provisions, it should include a caveat that such information is required only to the extent that it is not already provided in the E.S.-1 report.

> otherwise, shall be the reasonable and prudently incurred capital costs and expenses associated with Capital Spending Projects. The earned return on equity shall be calculated based on the capital structure and cost of debt, preferred stock, and other applicable sources of capital established in the general rate case.[36]

First, specific adjustments to the ROE used for purposes of determining the ESM are mentioned in the PBR statute, so actual (per books) ROE is not appropriately considered as part of the ESM, contrary to the Public Staff's language. The Companies' proposed rule allows for the Commission to approve any additional appropriate pro forma adjustments upfront during the PBR rate case rather than waiting for the annual review. If adjustments are left open for dispute in the annual review process, each annual review could turn into a full-blown rate case, with the utility and the Public Staff each advocating for a different set of pro forma adjustments. Not only does this significantly increase the utility's risk, it would also eliminate many of the regulatory efficiencies that could be gained through MYRPs, contrary to the well-understood policy goals. In addition, the Companies recommend that the Commission not add any additional pro forma adjustments in the rules in order to maintain flexibility to decide which adjustments are appropriate during consideration of each PBR application. The Companies' proposed rule strikes the right balance by having the Commission approve pro forma adjustments in its rate case order. Second, while it is not appropriate to include any specific pro forma adjustments in the rules beyond what is required in the statute, it is not appropriate at any time to lock in cost of debt as the Public Staff's proposed rule does. Cost of debt is a real cost to the utility

[36] Public Staff Proposed Rule R8-__(j)(2)e.

and can change significantly over three years just like any other costs considered in the test year. Actual debt costs change, and the ESM should reflect that.

The Companies also disagree with several of the Public Staff's proposed filing requirements for a PBR application. For instance, the Public Staff's proposed rule appears to require detailed forecasted test years when rates are not set on those test years.[37] This section requires the utility to include in its PBR application detailed forecasts of operating revenue, revenue deductions (or operating expenses), rate base components, and billing determinants. HB 951 is very specific in terms of how rates are to be established for each Rate Year in a MYRP and unless these items are related to the identified capital projects, they cannot be used to establish rates. Since they cannot be used to establish rates in the MYRP, it is inappropriate to require a utility to file these time-consuming detailed forecasts with its PBR application, which would once again increase administrative burdens without any commensurate benefit.[38] As discussed at length in the Companies' General Reply Comments, North Carolina's PBR statute does not include fully forecasted test years, so there is no reason for the filing requirements for a PBR application to include such information.

The Public Staff's proposed Rule R8-__(e)(6) requires a PBR application to "include a statement acknowledging that any true-up that is associated with any aspect of the PBR application that occurs after the end of an annual MYRP rate period will not constitute retroactive ratemaking." It is unclear what purpose such a provision would serve if the Commission applies the PBR statute as written. The Companies agree that the

[37] Public Staff Proposed Rule R8-__(e)(2).
[38] *See also*, PEG Report, at 22 ("these proposed filing requirements would require significant effort while providing little or no practical benefit to the Commission when setting rates.").

three annual adjustments spelled out in N.C. Gen. Stat. § 62-133.16 – decoupling, ESM, and PIMs – do not constitute retroactive ratemaking. However, any other "true-up" *would* constitute retroactive ratemaking – whether it is a "clawback" of savings that result from the capital costs of approved projects being less than projected levels, refunds for cancelled or delayed projects, or anything else. As discussed in the PEG Report, these clawbacks are not provided for in the statute, would weaken performance incentives, require significant resources to administer, and tend to be one-sided, *i.e.*, requiring the utility to compensate customers for any underspending while offering less protection to the utility against overspending.[39]

Another area of disagreement with the Public Staff is whether policy goals should be established in a separate docket in advance of a PBR application being filed. The Public Staff proposes that policy goals should be addressed a generic proceeding held every three years, and the policy goals approved in the generic docket would apply to all North Carolina electric utilities who thereafter file a PBR application.[40] The Companies oppose this approach. Policy goals and associated PIMs may differ on a case-by-case basis, and the PBR rule should allow them to be tailored to an individual utility – establishing a one-size-fits-all approach and divorcing policy goals from a utility's rate case, as the Public Staff suggests, would not lead to the best result. Policy goals and the associated PIMs should be considered in the context of a PBR rate case – not before. Moreover, as discussed at length in the Companies' response to NCSEA's recommendation of a separate policy goals docket, the statutory language does not require or even contemplate a distinct policy

[39] PEG Report, at 2, 11.
[40] Public Staff Proposed Rule R8-__(c)(1).

goals proceeding. Layering on additional proceedings beyond what is required by the PBR statute is inefficient and a waste of the Commission's and the parties' time and resources. As PEG points out, "Some of the parties' proposals may inadvertently hamper the Commission's ability to optimally administer PBR by predetermining results outside of specific MYRP proceedings – the proceedings where the Commission can best assess all aspects of PBR and consider utility-specific factors."[41]

In addition, the Companies do not agree that it is necessary for the Commission to establish special rules regarding the burden of proof for PBR rate cases as recommended in the Public Staff's proposed rule.[42] N.C. Gen. Stat. § 62-134(c) provides that "[a]t any hearing involving a rate changed or sought to be changed by the public utility, the burden of proof shall be upon the public utility to show that the changed rate is just and reasonable." Thus, the burden of proof to show that rates are just and reasonable is always on the utility. For the Company's prima facie case, all costs are presumed reasonable unless challenged; thus, intervenors have a burden of production in the event that they dispute an aspect of the utility's prima facie case. *See*, *e.g.*, *State ex rel. Utils. Comm'n v. Conservation Council*, 312 N.C. 59, 64 (1984) (utility's costs are "presumed to be reasonable" unless challenged); *State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76 (1982) ("The burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses…"). If the intervenor meets its burden of production, of

[41] PEG Report, at 2.
[42] Public Staff Proposed Rule R8-__(f)(7) and R8-__(l).

course, the ultimate burden of persuasion reverts or shifts to the utility, in accordance with N.C. Gen. Stat. § 62-134(c). Therefore, intervenors may not rest merely on arguments and theories, they must adduce actual evidence challenging some aspect of the Company's cost recovery case. The Commission has consistently followed this burden-shifting framework,[43] and there is no reason to establish a different standard for a rate case that also includes a PBR application. As a PBR rate case is clearly a "hearing involving a rate changed or sought to be changed by the public utility," N.C. Gen. Stat. § 62-134(c) and the case law interpreting § 62-134(c) applies.

Finally, in its comments, the Public Staff expresses concern over rate case timing under the MYRP approach and recommends that the Commission adopt a staggered filing approach for rate cases filed pursuant to N.C. Gen. Stat. § 62-133.16. Under the Public Staff's recommended approach, utilities would initially file PBR rate cases in designated years in three-year cycles. However, HB 951 provides no basis for the staggered rate case approach recommended by the Public Staff, and this approach will likely result in utilities filing additional traditional rate cases under N.C. Gen. Stat. § 62-133 as discussed in more detail below in response to CIGFUR's similar recommendation. HB 951 seeks to reduce the frequency of rate case filings and other complex regulatory proceedings; the Public Staff's suggested approach runs contrary to these policy goals.[44]

B. CIGFUR

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[43] *See*, *e.g.*, *Order on Remand*, Docket No. E-7, Sub 989 (October 23, 2013), p. 34.

[44] *See* PEG Report, at 5 ("MYRPs should approve the efficiency of regulation and the statutory framework should accomplish this, first and foremost by reducing the frequency of rate cases. Regulatory resources will thereby be freed up to focus more on utility capital expenditure ('capex') proposals, rate designs, and miscellaneous generic issues.")

CIGFUR argues that, at the end of the 36-month MYRP period, a utility's rates should revert back to pre-MYRP base rates established pursuant to N.C. Gen. Stat. § 62-133. CIGFUR contends that because the statute provides that an approved PBR application shall remain in effect for a plan period of not more than 36 months (*see* N.C. Gen. Stat. § 62-133.16(f)), rates must automatically default back to pre-MYRP base rates at the end of the three years. Quite simply this recommendation is not supported by PBR statute, punitive to the utility, inhibits the policy goals of HB 951, would create an inflexible regulatory process (that could potentially impose unnecessary regulatory burdens), and has no precedent in any other ratemaking construct in the country.

First, the limited duration of a PBR "plan period" prescribed by § 62-133.16(f) is intended to reasonably limit the period of time over which incremental capital investments are projected. While one of the important benefits of a MYRP is creating a cost recovery mechanism for smaller capital investments required to achieve North Carolina's policy goals without the need for frequent time-consuming and costly rate cases, this must be properly balanced with the need for a MYRP to be limited to a period in which a utility can accurately forecast future capital spending projects for forward-looking rate years. The legislature determined that a period of three years' worth of projected capital investments struck the right balance. However, limiting the MYRP "plan period" (*i.e.*, the period of time over which the utility's projected capital investment plans are to be considered) to three years is quite a different policy issue than whether Commission-approved rates reflecting prudent and reasonable investments should be completely discarded at the end of the MYRP, effectively denying recovery of prudent costs and forcing the utility to file a rate case even where such a step might not be necessary if the Rate Year 3 rates were to remain in place. If the legislature had intended for such a punitive and unreasonable outcome, it would have said so – it did not. Moreover, reverting to stale rates established using a historical test year that is four years old is punitive, not representative of the utility's current operations, and exposes the utility to increased – not decreased – regulatory lag when compared to traditional ratemaking. As noted by PEG, rates set at the outset of a plan would likely not reflect input prices, operating scale, or other cost pressures at the end of the plan. Utilities would be very likely to file rate cases in the last plan year in order to prevent such an outcome. Instead, in PEG's experience, when MYRPs end, base rates typically continue at their final-year levels until a commission approves new rates through a traditional rate case, a new MYRP, or another regulatory proceeding.[45]

The Public Staff and the Companies agree that Year 3 Rates should stay in effect upon expiration of the PBR plan period.[46] This position minimizes rate cases while preserving customer protection and preventing utility overearning through continuation of the ESM. By contrast, CIGFUR's proposal essentially guarantees rate case filings in the third year of the MYRP to ensure that new rates are in place by the end of the plan period.

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[45] PEG Report, at 15.

[46] *See* the Public Staff's proposed Rule R8-__(n): "Rates following Expiration of PBR Ratemaking Mechanisms – Following the expiration of the multiyear plan period, the rates for the current MYRP rate year shall remain in effect until further order of the Commission."

See also the Companies' proposed Rule R1-17(m)(10)(g.):

> If the electric public utility does not file a general rate case or successor PBR application to become effective after the final Rate Year, any approved PIM(s) shall expire but the base rates, Earnings Sharing Mechanism, and Decoupling Rate-making Mechanism effective for the final Rate Year will continue until the effective date of Commission-approved base rates from a subsequent general rate case. The electric public utility shall continue to file an Annual ESM and PIM(s) Review Report for each 12-month period beyond the end of the last Rate Year of the PBR plan for the ESM and continue to file annual adjustments to the Decoupling Rate-making Mechanism.

The policy goals encouraged under HB 951 and the implementation of PBR—including the ability of the Companies to receive more timely rate recognition of smaller capital investments needed to facilitate the energy transition—would be thwarted by such a counter-intuitive outcome. For these reasons, the Commission should adopt the post-MYRP rate outcome recommended by the Companies.

CIGFUR recommends that the Commission consider instituting a requirement that utilities stagger their PBR application filings by adopting a rule that a utility cannot file notice of intent to file PBR application if another utility has filed a PBR application within the preceding 180 days. There is no statutory basis for this requirement, and it is not a realistic requirement. A utility cannot control the timing of other companies' financial needs. CIGFUR's proposal could actually lead to increased workload because a utility blocked from filing a PBR application may be forced to file a rate case without a PBR if its rates are insufficient, and then 6 months later file another rate case with a PBR application. In other words, while the PBR process is intended to reduce the amount of rate cases needed and increase regulatory efficiencies, CIGFUR's overly rigid proposal could actually result in the opposite. It is also unclear how such a requirement would be administered. For example, what if both Dominion and DEC seek to file PBR applications at same time and have spent months preparing their cases for filing? Who gets to file? How does the Commission decide?[47] Finally, other parties are not necessarily

[47] While CIGFUR points to fuel rider proceedings to support its position, fuel rider proceedings are staggered within a 12-month period (June for DEC, September for DEP, and November for Dominion). Accordingly, fuel adjustments happen annually for every utility under Commission Rule R8-62, so the precise timing is not important. By contrast, staggering rate cases could mean a significant delay and requiring a "stay out" of at least 6 months (or a year if another utility files first on the 181st day) when another PBR application is pending, which could be devastating for an underearning utility.

disadvantaged when DEC and DEP rate case filings are close in time. Since the merger of Duke Energy and Progress Energy, all of DEC's and DEP's North Carolina general rate cases have been filed close together, which has resulted in synergies for everyone involved (including discovery, settlement discussions, consolidated hearing topics, stipulations of live testimony from same or similar witnesses to avoid duplicative cross-examination, etc.).

CIGFUR contends if a utility's PBR application is rejected and the utility elects to attempt the curing process, the timeframe for implementation of the utility's proposed *base rates* restarts (*i.e.*, a new 300-day clock would begin to run as of the date the utility refiles the "cured" PBR application). This is clearly not the intent of the statute. If the Commission rejects a PBR application, base rates under traditional ratemaking are still implemented. *See* N.C. Gen. Stat. § 62-133.16(d)(3) ("In the event that the Commission rejects a PBR application, the Commission shall nevertheless establish the electric public utility's base rates in accordance with G.S. 62-133 based on the PBR application."). Since there is no MYRP in place, the utility is free to file a new PBR application instead of curing the deficiencies of the rejected application. As a result, having the process for review of a cured application be the same as for a new application basically nullifies statute's provision that a utility have an opportunity to cure a deficiency. There would be no incentive to try to work with stakeholders to cure if rejection of a PBR plan resets the clock as CIGFUR suggests; instead, the utility may be better off filing an entirely new PBR application (rather than a "cured" application, which could just mean a few tweaks). This would be inefficient and a waste of the parties' resources. The provision for a utility to be able to cure deficiencies in a rejected PBR application was included in the draft PBR legislation recommended by the NERP.[48] This earlier version of the legislation did not provide the Commission the ability to modify a PBR application, only to approve or reject. In the NERP discussions, stakeholders expressed frustration that they might go through an entire PBR docket, and if the Commission rejected the PBR application, all of their efforts to implement a PBR framework would have been wasted. In response to that concern, the provision allowing a process to cure deficiencies was added to the NERP proposed legislation. Clearly, CIGFUR's proposal would nullify this provision. CIGFUR also suggests that the stakeholder process following the rejection of the PBR application should be facilitated by an independent and impartial third party. The Companies believe that this would add time and expense to the process, which should be a quick attempt to cure, not a redo of the initial rate case as CIGFUR seems to suggest.

CIGFUR recommends that the Commission require DEC and DEP[49] to include in their PBR applications an explanation, including all supporting data, of how each and every proposed capital expenditure for which the utility intends to recover costs through a MYRP complies with the "least cost" standard in N.C. Gen. Stat. § 62-2(a)(3a) and in HB 951. This requirement is not appropriate or necessary as a blanket obligation given that there are a variety of types investments that will be made under a MYRP, some of which will be required for general reliability and compliance purposes and others of which will be

[48] The NERP-recommended PBR legislation is the final four pages of NCSEA's Exhibit 4 to its initial comments.

[49] CIGFUR only recommends this least cost standard as a filing requirement for DEC and DEP. CIGFUR proposes several other filing requirements specific to DEC and DEP – some of which have nothing to do with the Carbon Plan – reasoning that because the Carbon Plan section of HB 951 applies only to the Companies, they should have additional filing requirements. However, the PBR section of HB 951 does not create any distinction between the various North Carolina utilities, so there is no basis to establish special requirements specific to PBR applications filed by the Companies.

specifically part of the "least cost" path to achieve carbon reduction targets established under HB 951. The nature of the justification provided for each investment will vary based on the nature of the investment and it is not appropriate to impose a one size fits all requirement.

CIGFUR also proposes a requirement that a utility indicate how it is going to remove a plant from rate base when it retires. First, this is not how ratemaking works. For normal plant retirements, the plant balance is removed from electric plant in service, but then it is credited to accumulated depreciation, which is also in rate base, so the level of overall rate base does not change. For abnormal retirements, the utility must request regulatory asset treatment from the Commission, and the Commission has typically allowed a return on these balances. Second, HB 951 is very specific on how Year 2 and Year 3 Base Rates are adjusted and says nothing about plant retirements.

In addition, CIGFUR suggests several across-the-board benchmarks for PIMs, including: the extent to which PIM-related expenses defer or displace capital expenditures such that the utility would ostensibly be indifferent to whether it meets customer and grid needs through rate-based traditional infrastructure, or through third-party owned DER; and PIMs should be designed so that they are narrowly tailored to achieve the intended policy goal and result in greater benefits to all classes of ratepayers than what the utility would or could have produced absent the PIM. First, as discussed above in the Companies' General Reply Comments, the Commission should decline to adopt specific guidelines for designing of PIMs outside of what is prescribed by statute in order to preserve flexibility. Second, it is unclear how a utility would show that it meets these benchmarks. Similarly, CIGFUR contends that each and every PIM should be tailored so that it provides demonstrable benefits to all classes of ratepayers and the utility shall provide a detailed statement of such anticipated benefits expected to flow to all classes of ratepayers as a result. HB 951 does not contain any requirement that a PIM should benefit all classes, and imposing such a requirement would severely limit the Companies' ability to propose PIMs relating to affordability issues, economic development, and other laudable goals. If a certain customer class does not benefit from a PIM, the allocation of the financial impacts of that PIM could exclude that class, such that the class is not impacted; however, there is no reason to prohibit such a PIM altogether. Again, the Companies' recommend rules that allow flexibility and the ability for the Commission and all parties to learn and adapt as policy issues evolve.

Finally, CIGFUR argues that discovery should be permitted to begin upon the filing by the utility to initiate a technical conference. The Companies oppose this recommendation. As outlined in the Companies' overview of a PBR rate case, the technical conference is designed to give the Commission and parties a preview of what is coming and is, in effect, a form of discovery in that the utilities will provide the parties with information relating to its planned T&D projects. From a practical perspective, conducting written discovery during the 60-day window prior to a rate case filing is unworkable – the utility is fully occupied with preparing its application, testimony, exhibits, and E-1s at this point, and written discovery would be burdensome, premature, and would divert the utility from preparing its filing and technical conference materials. As PEG observes, technical conferences are usually less formal than contested cases. The introduction of discovery into the technical conference might be difficult to accommodate within the 60-day period and would further appear to be premature when the utility could modify its plan based upon stakeholder feedback.[50]

C. CUCA

CUCA and Synapse start from the faulty premise that N.C. Gen. Stat. § 62-133.16 is more pro-utility than MYRPs in other states and suggest that the Commission should somehow course-correct with its rules. In doing so, they ignore that (a) North Carolina's PBR statute is the statute the Commission is directed to address via rulemaking, and the Commission cannot deviate from this statute; and (b) in many ways, the statute is less favorable to the utility than other MYRP mechanisms around the country, so even if it could, the Commission does not need to overcompensate by making rules more onerous and detrimental to the utility than the statute allows.

The Commission is not tasked to adopt rules to implement statutes in other states or the statute CUCA and Synapse wish had been passed. Synapse notes that "t]he elements set forth in North Carolina's PBR statute, *if implemented,* constitute a significant departure from both traditional ratemaking and the typical application of MYRP principles. Through shifting the balance of risk between customers and the utility, the statute's provisions could increase costs and risk substantially for utility customers if not balanced with robust customer protections."[51] First of all, there is no "if" – North Carolina's PBR statute *must* be implemented, and it must be implemented *as written*. Moreover, the statute already contains robust customer protections (many of which CUCA and Synapse downplay or ignore). For example, the ESM automatically refunds to customers 100% of earnings that

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[50] PEG Report, at 21.
[51] Synapse Report, at 1 (emphasis added).

are 50 basis points above the utility's allowed ROE. However, there is no corresponding ability for the utility to automatically collect additional revenue from customers if the utility is underearning. The utility's only remedy would be to file another rate case, which as discussed below, would result in significant regulatory lag. The asymmetrical narrow ESM therefore puts all the downside risk on the utility.

Synapse and CUCA also rely on the fact that the statute does not include a "stay out" provision to argue that the utility does not bear as much risk and that the Commission should, therefore, compensate with additional customer-centric provisions. However, for practical purposes, if the utility is underearning, it cannot increase rates for at least two years due to timing of rate year review. For example, under the Companies' proposed PBR schedule, if the utility underearned in Rate Year 1, the earliest it could file a rate case is 60 days after the end of Rate Year 1. Since the rate case process with a PBR application takes approximately 12 months (11 months for a Commission order and 1 month to calculate and implement new rates), the earliest the utility could have new rates effective from such a rate case is two months after the end of Rate Year 2 – just 10 months before the end of a three-year MYRP. If the utility underearns in Rate Years 2 or 3, there is no way that a utility could file a rate case and have new rates effective prior to the end of a three-year MYRP. So, the lack of "stay out" provision that CUCA highlights is actually not unreasonable and furthermore has very minimal practical impact. In reality, the utility bears the risk of underearning for a two-year period with no opportunity to recover the shortfall.

CUCA and Synapse also criticize North Carolina's PBR statute for not using external indices to set rates in the MYRP. They argue that because the annual revenue increases will be based on utility cost forecasts, rather than external benchmarks, the utility's incentives to constrain spending will be eroded. However, in other states that use external indices, such indices are often focused on O&M costs, with capital costs often recovered through separate trackers. N.C. Gen. Stat. § 62-133.16 does not provide for any escalation of O&M outside of what is tied to specific capital projects. As PEG noted, "In reality, the role of cost forecasts is fairly limited in the [North Carolina] statutory framework. Only the costs of discrete, identifiable capital projects for which the utility requests cost recovery are forecasted."[52] As such, if inflation is expected to be unusually high over the MYRP term, the utility cannot factor this into its Year 2 and Year 3 rates. Again, this adds more risk to the utility, compared to other mechanisms, especially when the utility is entering a period of anticipated increasing inflationary cost pressures.

In any case, the Commission cannot, through its rulemaking, layer on additional "protections" that the North Carolina legislature did not see fit to include in the statute. For instance, Synapse and CUCA urge the Commission to "include a proposal for returning any under-spend to customers through a rider or other mechanism and refrain from seeking recovery of any utility over-spend through the MYRP. This proposal would provide greater protection for ratepayers than the statute's proscribed 50 basis point cap on overearnings."[53] However, a comprehensive true-up or "one way cost reconciliation" as suggested by Synapse is not permitted by the statute – there is simply no provision in HB 951 for returning underspend to customers (or collecting cost overruns, for that matter).

[52] *See* PEG Report, at 9.
[53] Synapse Report, at 2, 12.

Moreover, there may be good reasons why capital costs could be lower than forecasted, including normal market fluctuations and efficient management.

Along the same lines, CUCA and Synapse argue that because the annual revenue increases will be based on utility cost forecasts, rather than external benchmarks, the utility's incentive to constrain spending will be eroded. However, the Commission has to approve discrete capital projects, and to the extent CUCA/Synapse's concern is with the accuracy of capital cost estimates, the utility's estimates will be fully vetted in the rate case. The asymmetrical ESM also serves as a safety valve to prevent overearning as a result of underspending, and ultimately, the Commission or the Public Staff can request to initiate a proceeding to adjust rates if rates are not reasonable.

Synapse also recommends that a PBR application be required to include a cost benchmarking study using data from peer utilities. More specifically, they request that utilities submit data from the largest group of peer utilities available that are electric-only investor-owned utilities with ownership of generating resources and at least 400,000 customers.[54] It is unclear how many utilities this would encompass and how granular the data would be (*e.g.,* would such a study include detailed peer data for every capital item included in a utility's forecast?). Such a benchmarking study is unnecessary, overly burdensome, and inconsistent with the statute. The Public Staff, intervenors, and the Commission will have ample opportunity to examine a utility's forecasted and actual capital expenditures through the process set out in the PBR statute and the Companies' proposed rules. Plus, other than the specific increases related to certain capital projects,

[54] *Id*. at 2, 11.

the utility retains all of the same cost containment incentives of traditional ratemaking. The utility must manage negative regulatory lag from items such as increases in O&M, general taxes, material and supplies, and depreciation not related to specific MYRP projects with positive regulatory lag from items such as load growth and depreciation of existing plant. If the utility underearns, it must underearn for two years before rates can be adjusted. As a result, there is a strong incentive for a utility to contain costs.

Other potentially onerous filing requirements that CUCA and Synapse recommend include, without limitation, providing a summary of alternatives that are considered, presenting specific details on each large project, and providing specific details on deviations. Depending on what is meant by "specific details" and how "large" is defined, the information requested may exceed what a utility's engineers and project managers are able to provide considering the number of projects that are likely to be included in a MYRP. In addition, depending on how a project is structured and the reasons for the project, there may not be many alternatives to present. For instance, if a utility is required by law or regulation to implement a capital project, it would be unnecessary to prepare a cost-benefit analysis or weigh alternatives. The filing requirements and reporting obligations contained in the Companies' proposed rules strike the right balance – they provide detailed and relevant information necessary for the Commission and parties to thoroughly evaluate a PBR application and conduct subsequent annual reviews, without requiring immaterial information that is unduly burdensome to prepare.

Synapse suggests a utility proposing a PBR plan also be required to demonstrate post-test year cost increases do not exceed forecasts of regional public utility cost escalation rates and that the average customer rates (by class) and bills (for residential customers) will be within a reasonable range of peer utilities' rates and bills. As an initial matter, Synapse's concerns have no grounding in reality, as the Companies have through the cost of service regulatory model consistently delivered outstanding reliability and customer service at rates below the national average. But as a matter of principle, Synapse's suggestion that comparisons to other utility rates should somehow guide the Commission's PBR determinations has no basis in HB 951 and is contrary to well-established law in North Carolina.[55] The rates to be set by the Commission must be just and reasonable and must reasonably and fairly reflect the cost to serve *North Carolina* customers.[56] There is no basis in law to impose a separate limitation on the utility's rates.

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[55] *See, e.g., State ex rel. Utils. Comm'n v. Lee Tel. Co.*, 263 N.C. 702, 140 S.E.2d 319 (1965) ("Where company operates in two or more states, operations are treated as separate businesses for purpose of rate regulation, and inadequate return in foreign state would not of itself justify rate increase in North Carolina, nor would high rate of return in foreign state justify less than fair and reasonable rate in North Carolina."); *see also, Order Approving Merger Subject to Regulatory Conditions & Code of Conduct*, Docket No. E-7, Sub 795, at 71 (March 24, 2006) ("The Commission agrees with Duke Energy witness Hager that the reliance of CIGFUR III on rate disparities between North and South Carolina, standing alone, is contrary to North Carolina law.") (citing *State ex rel. Corp. Comm'n v. Cannon Mfg. Co.*, 185 N.C. 17, 28, 116 S.E. 178, 185 (1923) ("The Corporation Commission [now Utilities Commission] in this State is empowered and directed to make reasonable and just rates as applied to the distribution and sale of power in this State and not otherwise, and such power cannot be directly controlled or weakened by conditions existent in other states, either from the action or nonaction of official bodies there, or the dealings between private parties. To hold otherwise would, in its practical operation, be to withdraw or nullify the powers that the statute professes to confer and should not for a moment be entertained.")).

[56] The Commission is required to set just and reasonable rates for public utilities. N.C. Gen. Stat. § 62-130(a). Just and reasonable rates are those that provide the utility an opportunity to earn a fair return on its property and are fair to the utility's customers. *State ex rel. Utils. Comm'n v. Piedmont Nat. Gas Co.*, 254 N.C. 536, 119 S.E.2d 469 (1961); *State ex rel. Utils. Comm'n v. Duke Power Co*., 285 N.C. 377, 206 S.E.2d 269 (1974). To achieve just and reasonable rates, the utility's revenue must be sufficient to cover the utility's cost of service, plus allow the utility the opportunity to earn a reasonable return on its rate base but must be fair to customers. To this end, the North Carolina Supreme Court has counseled:

> [T]he fixing of "reasonable and just" rates involves a balancing of shareholder and consumer interests. The Commission must therefore set rates which will protect both the right of the public utility to earn a fair rate of return for its shareholders and ensure its financial integrity, while also protecting the right of the utility's intrastate customers

Moreover, North Carolina's costs and rates could increase more than regional utilities' for a variety of reasons driven by differing policy, law, regulation etc., and the Commission should not be hamstrung by the decisions of other jurisdictions. In addition, as explained by PEG, Synapse's proposal that cost increases in Years 2 and 3 of the MYRP should not be permitted to exceed forecasts of regional public utility cost escalation rates is unreasonable because the statute already includes a reasonable 4% cap on the annual increase in base revenue requirements, and it is widely recognized that capex requirements of utilities sometimes cause their cost trends to deviate from industry trends for several years.[57]

Synapse recommends that a utility proposing a PBR plan be required to demonstrate that the PBR plan is more likely than current regulation to advance the goals of utility cost control, lower rates, and reduced administrative burden. As an initial matter, it is well recognized that PBR is, in fact, designed to advance policy goals such as those established by the General Assembly in HB 951. Moreover, it should go without saying that it is reasonable to assume that in authorizing PBR, the General Assembly viewed PBR as a necessary tool to implement the state's energy policy objectives—elsewise, the General Assembly would not have provided such tools to the Commission. Had the General Assembly intended the PBR tools to only be used under a narrow set of

> to pay a retail rate which reasonably and fairly reflects the cost of service rendered on their behalf.

State ex rel. Utils. Comm'n v. Nantahala Power & Light Co., 313 N.C. 614, 691, 332 S.E.2d 397, 474 (1985), rev'd on other grounds, 476 U.S. 953, 90 L.Ed.2d 943 (1986), appeal after remand, 324 N.C. 478, 380 S.E.2d 112 (1989). Thus, if the Commission were to set rates based on peer utilities', as CUCA urges, to the extent that the rates were to impair the Company's ability to earn its authorized return, such impairment would constitute an unconstitutional taking of property. *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).
[57] PEG Report, at 25-26.

circumstances, it could have so indicated but instead, the Commission simply made PBR available for use by the Commission. Synapse's recommendation would establish an evidentiary hurdle – in effect, a burden of proof – that is not contemplated by the statute and is unnecessary given that the legislature has already decided that PBR is a ratemaking approach that should be encouraged.[58] Imposing an additional hurdle on the utility to show that PBR is more likely than traditional regulation to advance certain goals that are not even included in the North Carolina statute is inconsistent with this legislation.

D. NCSEA

In its initial comments, NCSEA offers several recommendations that impact (and delay) nearly every aspect of PBR implementation. For some recommendations, NCSEA relies on incorrect readings and interpretations of HB 951. Furthermore, NCSEA repeatedly asks that this Commission deviate from the statutory language and framework

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[58] The 1995 Massachusetts decision upon which Synapse bases this recommendation (aptly titled, "Investigation by the Department on its own motion into the theory and implementation of incentive regulation for electric and gas companies under its jurisdiction") is not based on any enabling legislation or statutory criteria, but rather was an attempt to set parameters for utilities who wish to deviate from traditional cost-of-service ratemaking. The Massachusetts Department of Public Utilities notes upfront that despite the Department's reliance on cost-of-service/rate of return regulation in recent decades, the form and method of regulation of public utilities is not fixed by statute, and it has the authority to consider alternate methods of regulation in setting just and reasonable rates. *See Massachusetts Department of Public Utilities Investigation by the Department on its own motion into the theory and implementation of incentive regulation for electric and gas companies under its jurisdiction*, D.P.U. 94-158 (1995), pp. 4, 35. Available at https://www.mass.gov/doc/94- 158pdf/download.

Accordingly, the Department decided that if a utility would like to propose a new incentive approach it must demonstrate that this approach "is more likely than current regulation to advance the Department's traditional goals of safe and reliable energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation." *Id*. at 48. Here, the North Carolina legislature has already decided that the specific form of PBR it has authorized in § 62-133.16 is an alternative form of ratemaking that the Commission may allow – provided, of course, that the proposed PBR would result in just and reasonable rates, is in the public interest, and is consistent with the criteria established in the statute and Commission rules.

established by the General Assembly to impose new requirements and standards that prolong PBR implementation.

NCSEA proposes multiple rules that prevent utilities from submitting PBR applications until the Commission resolves issues in separate regulatory proceedings. For example, NCSEA argues that the Commission should prohibit utilities from submitting PBR applications until January 1, 2023. It explains that this restriction is designed to ensure that the Commission's Carbon Plan – due December 31, 2022 – would inform capital investments included in PBR proposals. NCSEA claims that "allowing Duke to file a PBR application prior to the finalization of the Commission's first Carbon Plan would seriously undermine the General Assembly's intent in adopting House Bill 951."[59]

NCSEA's arguments disregard the plain language of HB 951. Section 4.(b) of HB 951 provides that "[t]he Commission shall adopt rules as required by G.S. 62-133.16(j), as enacted by subsection (a) of this section, *no later than* 120 days after the date this section becomes law" (emphasis added) – *i.e.*, February 10, 2022. This expedited rulemaking period makes plain that the PBR option is to be available in North Carolina in short order, not more than a year in the future as NCSEA suggests. Section 4.(c) of HB 951 provides further that the PBR section of the statute "is effective when it becomes law and applies to any rate-making mechanisms filed by an electric public utility *on or after the date that rules adopted pursuant to G.S. 62-133.16, as enacted by subsection (a) of this section, become effective*" (emphasis added). In North Carolina, legislative intent is ascertained by the plain words of the statute.[60] Here, HB 951 requires that the Commission adopt PBR

[59] NCSEA Initial Comments at 3.
[60] *Rhyne v. K-Mart Corp.*, 149 N.C. App. 672, 562 S.E. 2d 82 (2002).

implementation rules no later than February 10, 2022 and expressly allows a utility to file for approval of a PBR ratemaking mechanism once those rules are effective. NCSEA's position that the Commission should, through its rules, essentially postpone the effective date of the PBR statute would render these statutory provisions and the specific deadline for adoption of PBR rules meaningless. *See Winkler v. N. Carolina State Bd. of Plumbing*, 374 N.C. 726, 730, 843 S.E.2d 207, 210 (2020) ("[C]ourts should construe the statute so that none of its provisions shall be rendered useless or redundant."); *Williams v. Holsclaw*, 128 N.C. App. 205, 212, *aff'd*, 349 N.C. 225 (1998) ("[A]n individual section of a statute will not be interpreted in such a manner that renders another provision of the same statue meaningless.").

The Companies certainly appreciate the importance of the Carbon Plan and recognize that capital spending projects that advance the Carbon Plan will be reflected in their rate case filings in accordance with applicable statutes and Commission orders. However, the General Assembly established a statutory timeline for PBR independent of the Carbon Plan – a timeline that clearly contemplates and allows PBR filings prior to January 1, 2023.

NCSEA also recommends that the Commission establish a separate docket, six months prior to a PBR application filing, to determine policy goals, PIMs, and tracking metrics (what it refers to as a "Policy Consideration Docket"). Under this Policy Consideration Docket approach, the Commission would (1) establish policy goals that the future PBR application should address; (2) establish PIMs for the PBR application and establish PIM criteria for approval; and (3) develop tracking metrics *in a separate* *proceeding prior to a utility submitting a PBR application*. The Companies oppose this approach.

First, a Policy Consideration Docket is unnecessary. HB 951 establishes initial policy goals and principles that should guide initial PBR implementation. The NERP facilitated a robust stakeholder process that yielded a variety of policy proposals and proposed legislation that were carried forward into legislation proposed in 2021. To the extent that the parties wish to propose and the Commission wishes to consider policy goals and objectives in addition to the initial policy goals outlined in HB 951, they may do so in the context of a PBR rate case.[61] In any event, the initial policy goals established by HB 951 coupled with existing Commission policy provide a solid foundation for initiating the PBR process without an independent docket.

Second, a rule prohibiting utilities from employing PBR mechanisms until the Commission and stakeholders establish and deliberate additional policy issues in a separate docket extends beyond the text, purpose, and intent behind HB 951. NCSEA argues that N.C. Gen Stat § 62-133.16(a)(8) anticipates that policy goals may be set by the Commission "prior to and independent of" a PBR application. However, when read in context, that section does not support NCSEA's argument. Section 62-133.16(a)(8) defines "Policy Goal," in relevant part, as "an expected or anticipated achievement of operational efficiency, cost-savings, or reliability of electric service that is greater than that which already is required by State or federal law or regulation, including standards the

[61] NCSEA emphasizes that HB 951 does not prohibit intervenors from also recommending performance and tracking metrics, which it contends should be proposed, debated, and decided in the Policy Considerations Docket. The Companies agree that parties other than the utilities can propose performance and tracking metrics; however, the proper venue for such proposals is a rate case docket after a PBR application has been filed.

Commission has established by order prior to and independent of a PBR application…." All this means is that the policy goal must be greater than that which is already required by an existing Commission order in an unrelated docket – not that the Commission has to establish a separate docket to pre-establish policy goals. To read it the way NCSEA suggests, would make no sense – why would a policy goal have to be greater than what the Commission just established immediately prior to a PBR application? The actual language, when read in context with the "greater than" language, merely establishes that a utility should not be rewarded for meeting an existing standard that it is already required to meet – whether that standard is in a law, regulation, or prior Commission order.

NCSEA also cites the Hawaii PBR development process as an example supporting its recommendation of a Policy Consideration Docket. The Hawaii legislature implemented a multiyear process for establishing policy goals and debating PBR framework issues. However, the General Assembly neither took such action nor authorized this Commission to do so. Instead, HB 951 includes specific timelines and targeted deadlines for initial implementation. HB 951 tasks this Commission with implementing a North Carolina statute passed by the North Carolina General Assembly – not Hawaii's. Of note is the fact that Hawaii already had MYRPs and limited PIMs in place for years before the referenced process to establish policy goals was initiated. Hawaii's example actually does not support NCSEA's proposal that a Policy Consideration Docket be held before any MYRP or PIM can be implemented. Regardless, in North Carolina, PIMs are not set in separate docket but intended to be evaluated as part of the PBR filing.

Along the same lines, NCSEA argues that the Commission should approve capital spending projects in the context of the Carbon Plan and *before a utility submits a PBR* *application*. This recommendation relies upon a misreading of N.C. Gen. Stat. § 62-133.16(c)(1)a, which provides, in relevant part, that:

> 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. *Subsequent changes in base rates in the second and third rate years of the MYRP shall be based on projected incremental* ***Commission-authorized*** *capital investments* that will be used and useful during the rate year and associated expenses, net of operating benefits, including operation and maintenance savings, and depreciation of rate base associated with the capital investments, that are incurred or realized during each rate year of the MYRP period…

(emphasis added). NCSEA argues that "Commission-authorized," as used in this Section, means that Commission pre-approval, in a separate docket, is required for all capital investments that will be included in a PBR application. Importantly though, HB 951 only uses "Commission-authorized" when describing Year 2 and Year 3 capital spending projects, indicating that the General Assembly intended for the Commission to authorize these projects, along with Year 1 projects, in the order approving or modifying a proposed PBR application and MYRP. If the General Assembly intended to establish a separate process prior to the filing of a PBR application for pre-approval of capital spending projects, it would have used specific language outlining such a pre-approval process. While, of course, future capital spending projects that are part of a MYRP must be authorized by the Commission, this is done so in the context of a PBR rate case – not beforehand.[62] To require the Commission to pre-approve projects more than a year in advance of when the MYRP starts is not beneficial and not at all intended by the legislation.[63]

Regarding tracking and performance metrics, NCSEA recommends that the Commission adopt monthly reporting requirements for PBR rate plans that would include (1) specific tracking metrics; (2) average customer class data; and (3) monthly surveillance reports. NCSEA also asks that the Commission establish transparency rules that would require utilities to submit detailed plans and support for proposed PBR investments. The Companies oppose monthly reporting requirements. From a practical perspective, quarterly reporting would provide the Commission with the most useful information for evaluating PBR plan performance. As noted above, the Companies already provide the Commission with E.S.-1 surveillance reports on quarterly basis.

Finally, like CIGFUR, NCSEA argues that parties should be permitted to conduct discovery in connection with the technical conference and that at the end of MYRP, rates should revert to base rates set prior to Years 1, 2, and 3 of the MYRP. For the reasons set forth in the Companies' rebuttal of these recommendations in the section addressing CIGFUR's comments, these recommendations should be rejected.

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[62] CIGFUR agrees with the Companies that projects are authorized by the Commission to be included in the MYRP *during the PBR application process*, not prior to, which affords all of the parties the full ability to litigate the issues. CIGFUR Initial Comments, at 6-7.

[63] NCSEA also urges the Commission to allow the parties to conduct discovery related to the technical conference presentations during the pendency of the technical conference process based on their mistaken assumption that if they were not allowed to do so, the Commission would authorize capital investments without intervenors having the opportunity to conduct discovery. Because the Commission should authorize capital spending projects as part of the rate case (not beforehand), this concern is moot – the parties will have ample opportunity to conduct discovery relating to capital investments during a PBR rate case prior to Commission authorization.

In sum, it is clear that under HB 951, the legislature wanted to ensure that the Commission initiated an expeditious process that would advance toward providing PBR as a rate option in North Carolina. NCSEA's proposed Policy Considerations Docket approach, when combined with its recommendation that utilities be prohibited from filing a PBR rate case until 2023, and the recommendation that the Commission separately review and pre-approve capital spending projects prior to a PBR filing, could delay PBR implementation by years and negate nearly all the potential efficiency benefits associated with MYRPs by burying the Commission and the parties with a proliferation of unnecessary filings and proceedings.

E. NCJC, et. al

The North Carolina Justice Center ("NCJC"), North Carolina Housing Coalition ("NCHC"), Sierra Club, and the Southern Alliance for Clean Energy ("SACE") (collectively "NCJC et al.") developed proposed rules that rectify what they perceive to be structural and policy shortcomings of HB 951 through new requirements, standards, and constraints that are not permitted by the statute.

Under the NCJC et al. proposed partial rules, PBR applications must contain six Commission-required PIMs, including reduction in non-fuel cost per kWh, maintenance of adequate reliability, DER promotion and advancement, accelerated achievement of carbon goals, and EE program deployment improvements ("Required PIMs"). The proposed rule states that "the utility shall include the specific required PIMs . . . regardless whether the utility supports adoption of these PIMs."[64] Rules requiring that PBR applications include

[64] Comments & Partial Proposed Rules Submitted on Behalf of North Carolina Justice Center, North Carolina Housing Coalition, Sierra Club, Sierra Club, & Southern Alliance for Clean Energy, at 31 ("NCJC et al. Comments").

six PIMs covering specific topics contradict the flexible framework established by the General Assembly. Importantly, HB 951 requires that PBR applications include at least one PIM proposal and also outline certain policy and structural requirements for PIM proposals.[65] As a matter of policy, this flexibility makes sense: HB 951's structure allows both the Commission and utilities to adapt as policy goals and objectives change over time. Therefore, the Commission should consider the content, propriety, and merit of PIM proposals in each PBR application. This less prescriptive approach will facilitate learning and innovation as the Commission and utilities employ new regulatory tools under this new legislative framework, in contrast with the recommendation of NCJC et al., which hard code in requirements that would inhibit the Commission's future flexibility.

NCJC et al. also recommend additional burden of proof requirements for revenue decoupling adjustments included in PBR applications. The proposed rule requires that parties model and consider rate designs that reduce fixed charges or incorporate inclining block rate adjustments. The Commission should reject this recommendation for the very simple and obvious reason that HB 951 requires PBR applications to include decoupling adjustments and NCJC et al.'s proposed rule would burden utilities with justifying a statutorily-required adjustment.

NCJC et al. argue further that HB 951 retains traditional cost-of-service framework features and believe that in so doing, "HB 951 is unusual in comparison with other leading examples of PBR from other states."[66] In an effort to "partially overcome this shortcoming," the NCJC et al. proposed rule adds new criteria for PBR applications—

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[65] *See* N.C. Gen. Stat. § 62-133(c)(3)-(4).
[66] NCJC et al. Comments, at 11.

requiring that utilities address affordability, adhere to carbon reduction goals, and increase EE and DER adoption.[67] NCJC et al. also request that the Commission mitigate the negative impacts of HB 951's requirement that the minimum system method be used for allocating distribution system costs between customer classes. According to NCJC et al., this method favors large utility customers and inflates residential customer costs. Again, N.C. Gen. Stat. § 62-133.16(j) instructs the Commission to adopt rules for implementing this legislation. Whether other state legislatures included or excluded certain concepts or provisions should not drive this Commission's process for implementing North Carolina law.

Regarding tracking and performance metrics, NCJC et al. recommend that the Commission establish: (1) clearly defined metrics for evaluating PIMs; (2) a supplemental rulemaking process to establish PIMs related to low-income affordability pursuant to the recommendations of the Affordability Collaborative; and (3) an integration of concrete goals for carbon reduction PIMs connected to HB 951 Part I's carbon reduction plan. NCJC et al. also includes a rule that prohibits the Companies from submitting a PBR application until after the Affordability Collaborative issues a final report and recommendations to the Commission. Simply put, the Act does not support these recommendations. Section 1(4) of HB 951 specifically affords the Commission latitude in achieving carbon reduction goals, including extending deadlines for limited exceptions listed in the statute. In addition, N.C. Gen. Stat. § 62-133.16(a)(8) prohibits PIMs that are more stringent than state or federal environmental laws. The Companies also disagree with

[67] NCJC et al. note that "the reliance of traditional cost-of-service regulation is explicitly reaffirmed in the section detailing what should apply to a multi-year rate plan." *See id.* at 12.

delaying PBR implementation until the Affordability Collaborative issues a final report. As it stands, the Affordability Collaborative could develop a suite of program proposals or recommendations that would not be appropriate as PIMs. The legislature established timelines for PBR implementation in North Carolina and the Commission should reject requests that ignore those timelines in anticipation of outcomes in separate regulatory proceedings. PEG acknowledges that while it is important to develop sound affordability and environmental metrics, as contemplated by the Affordability Collaborative and Carbon Plan processes, MYRP applications should not be delayed as a result. "There are never 'perfect' rules that can anticipate every issue. A supplemental rulemaking won't solve that problem, but it may delay progress. Stakeholders and the Commission can incorporate any new information and decisions resulting from other proceedings [such as the Affordability Collaborative and Carbon Plan] into PIMs on an ongoing basis — as the need arises."[68]

NCJC et al. also highlight several public interest factors that the Commission statutorily "may" consider when evaluating PBR plans; the NCJC et al. proposed rule converts this into a requirement.[69] Importantly, N.C. Gen. Stat. § 62-133.16(d)(1) and (2) set forth the standard the Commission must apply in evaluating PBR applications.

[68] PEG Report, at 19.

[69] *See* N.C. Gen. Stat. § 62-133.16(d)(2):

> 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; and 11) Promotes rate designs that yield peak load reduction or beneficial load-shaping.

(emphasis added).

Throughout HB 951, the legislature intentionally uses "may" and "shall" to differentiate permissive from mandatory factors relevant to the review process. To that end, the provisions in N.C. Gen. Stat. § 62-133.16 (2)(c), (d), (e) and (f) provide that the Commission *may* consider whether a PBR application encourages DERs, reduces low-income energy burdens, encourages EE and encourages carbon reductions. Again, NCJC et al. disagree with the permissive statutory language and propose a rule affirmatively addressing issues important to their constituencies. It would be improper for the Commission to impose requirements by rule that the statute says *may* be considered.[70]

V. CONCLUSION

For the reasons set forth herein, the Companies respectfully request that the Commission adopt the Companies' proposed rules filed in the above-referenced docket on November 9, 2021.

Respectfully submitted, this the 17th day of December, 2021.

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[70] *See Chisum v. Campagna*, 376 N.C. 680, 699, 855 S.E.2d 173, 187 (2021) (use of "may" generally connotes permissive or discretionary action and does not mandate or compel a particular act).

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Contents

1. Introduction and Executive Summary

In October 2021 Governor Cooper signed into law House Bill 951 which sanctions multiyear rate plans ("MYRPs") and other kinds of performance-based regulation ("PBR") for North Carolina electric utilities. The law directed the North Carolina Utilities Commission ("the Commission" or "NCUC") to establish rules for implementing PBR. Four rules issues were specifically raised in the law.

- Specific implementation procedures and requirements
- Criteria for evaluating PBR applications
- Parameters for a technical conference process
- Process for addressing a rejected PBR application.

Parties filed initial comments in the rules proceeding (Docket No. E-100, Sub 178) on November 9th. A second round of comments are due December 17th.

Pacific Economics Group Research LLC ("PEG") is a leading consultancy in the field of PBR for energy utilities. Our personnel have been active in the field since the late 1980s. We have written several surveys and white papers on alternatives to traditional rate regulation ("Altreg") for the Edison Electric Institute.[1] Our many publications on PBR include a recent report on MYRPs for Lawrence Berkeley National Laboratory.[2]

Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively the "Companies") have asked PEG to review and comment on North Carolina's new PBR legislation and the first round of comments in the rules proceeding. This is our report. In Section 2 we review and appraise the statutory framework for PBR that is set forth in House Bill 951. There follows in Section 3 a discussion of the initial PBR rules comments. An appendix contains an overview of PBR, including multiyear rate plans, decoupling, performance incentive mechanisms, and earnings sharing mechanisms, a glossary of ratemaking terms, and details the PBR experience of PEG.

We conclude from our evaluation of the statutory framework that it provides for a thoughtful and cautious transition to PBR in North Carolina. Compromises between the negotiating parties produced a fair balance between utility and stakeholder interests. Under the statutory framework, incentives to control cost will be strengthened relative to a continuation of current regulation and progress should be made toward the state's policy goals while still providing utilities a reasonable opportunity to earn their allowed returns on equity. A more efficient regulatory system should free up resources to address more carefully the continuing swirl of new regulatory issues. Customer protections

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[1] See for example, Lowry, M. N., Makos, M., and Waschbusch, G. "Alternative Regulation for Emerging Utility Challenges: 2015 Update," for Edison Electric Institute, November 2015.

[2] Lowry, M.N., Makos, M., Deason, J., and Schwartz, L., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," for Lawrence Berkeley National Laboratory, Grid Modernization Laboratory Consortium, U.S. Department of Energy, July 2017.

are numerous and include a cap on utility earnings, increased rate certainty, and commission discretion over funding for many capex projects.

Parties addressed a wide array of issues in the initial round of comments on PBR rules. While we agree with some of these comments we found others to be controversial.

First, there are assertions that the statutory framework favors utilities and omits some provisions of state of the art PBR plans. In our report we explain that the statutory framework has an unusually extensive array of customer protections and draws ideas from many approved MYRPs plans.

Second, parties propose filing requirements, policy proceedings, and implementation proceedings that are not specifically authorized in House Bill 951. Many of these additional requirements and proceedings would offer limited value and could significantly reduce the regulatory efficiency of MYRPs or even make MYRPs less efficient than current regulation. Additionally, some of these proposals may inadvertently hamper the Commission's ability to optimally administer PBR by predetermining results outside of specific MYRP proceedings – the proceedings where the Commission can best assess all aspects of PBR and consider utility-specific factors.

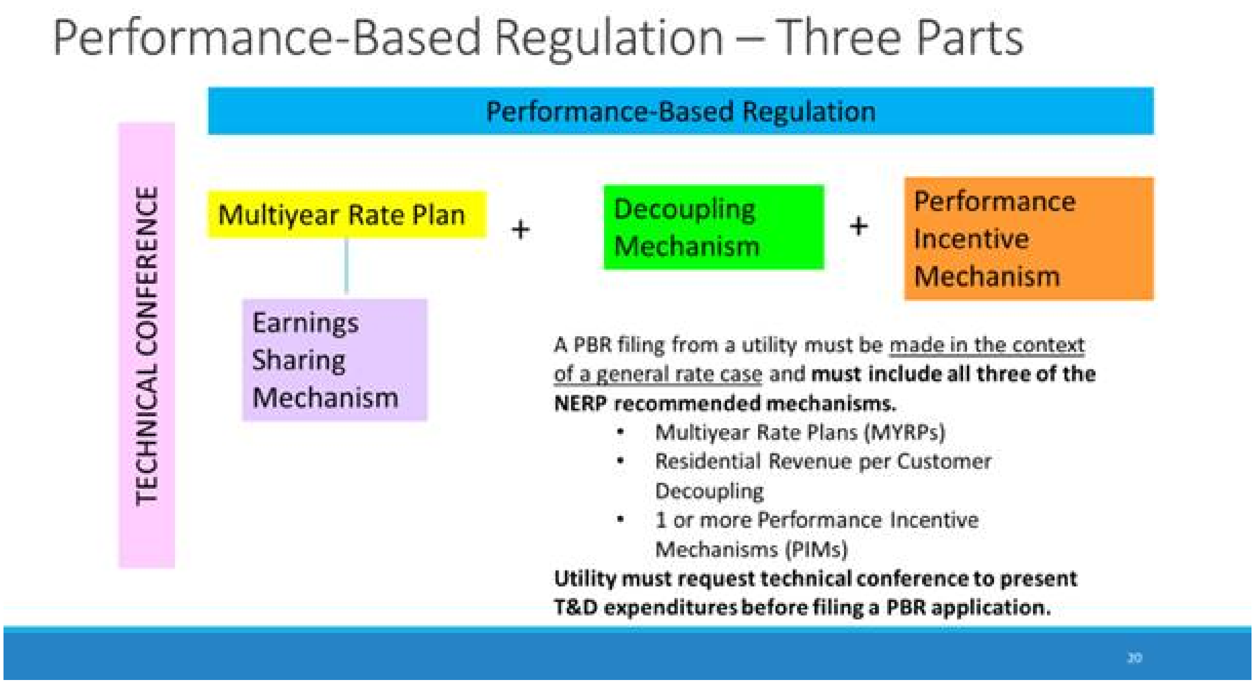
Third, while the statute provides clear direction regarding how rate escalation would be established during the term of an MYRP, we are concerned that requests for information on future costs could devolve into a fully forecasted approach to establishing the revenue requirement. There are several precedents for the general approach to revenue escalation that is featured in the framework.

Fourth, parties propose reconciliations to ensure that utilities are compensated for no more than their actual costs — particularly the costs of new investments. These clawbacks are not provided for in the statute, would weaken performance incentives, require significant resources to administer, and tend to be one-sided, i.e., requiring the utility to compensate customers for any underspending while offering less protection to the utility against overspending.

2. North Carolina Legislative Guidelines

2.1. The Legislated PBR Template

House Bill 951 authorizes the Commission to approve PBR for retail rates of North Carolina electric utilities. Utility applications for PBR must include a multiyear rate plan ("MYRP") with the following features that we will call the statutory framework. These features are summarized in the diagram below.



In summary House Bill 951 provides for the following.

- Revenue decoupling applies to residential services (which may exclude electric vehicle rates).
- Revenue growth between rate cases is determined by several provisions.
    - Revenue per customer decoupling automatically escalates allowed residential revenue for annual customer growth.
    - Commercial and industrial ("C&I") revenue would continue to rise and fall, as it now does, with changes to C&I billing determinants.
    - The revenue requirement is escalated in each plan year for the Commission-approved annual cost of certain itemized additions to the value of plant.

    - No other provision escalates or reduces revenue for most operation and maintenance ("O&M") expenses, miscellaneous plant additions that aren't itemized, or the (depreciating) value of older plant.
    - A 4% cap is placed on annual revenue requirement growth compared to the initial revenue requirement.
    - Utilities may continue to request separate deferral treatment of the costs of any large generation plant additions (e.g., $500 million + projects).
    - Utilities may continue to also request deferral treatment of the costs of extraordinary events.

- Established rate riders (e.g., for fuel expenses) may continue.
- An asymmetrical earnings-sharing mechanism ("ESM") returns to customers all weather-normalized earnings that exceed the authorized rate of return on equity ("ROE") by more than 50 basis points.
- The Company can file a rate case after its weather-normalized ROE falls below that authorized for a year.
- A performance metric system features targeted performance incentive mechanisms ("PIMs") and additional tracking metrics.
- The term of the plan is 3 years.
- A pre-filing technical conference is held to discuss transmission and distribution projects.
- Eleven criteria are suggested to guide the assessment of PBR applications.

2.2. Appraisal of the Template

Fairness

The statutory framework approach seems fair on balance. The template does provide some benefits to utilities:

- Residential revenue is automatically escalated for customer growth instead of growing with billing determinants.
- Residential revenue decoupling reduces the risk of declines in average use of power from all sources.
- There is timely funding for the approved cost of some plant additions.
- Separate and deferred ratemaking treatment of major generation plant additions is possible but not guaranteed.
- A utility can file a rate case if it has underearned.

However, the framework also provides several customer protections:

- Initial rates will be established in a proceeding that has a historical test year.
- While residential revenue is escalated automatically for residential customer growth and C&I revenue rises with billing determinant growth, the corresponding cost of service is also driven by input price inflation (which tends to be more rapid than the growth in customers and other billing determinants), by capital expenditures that are unrelated to service growth and difficult to itemize, and possibly also by new safety, reliability or environmental requirements.
- There is a 4% cap on annual revenue requirement growth.
- The Commission decides whether to fund a utility's proposals for itemized plant additions. It also decides whether to grant deferral treatment of major generation plant additions that cannot be included in the MYRP.
- The utility absorbs the risk of fluctuations in C&I loads. Downturns in these loads constitutes a significant business risk, particularly during periods of economic contraction (such as from pandemics, troughs of a business cycle, natural disasters, etc.)
- Rate growth is more predictable.
- The ESM asymmetrically favors customers. The entirety of weather-normalized earnings in excess of a modest 50 basis point dead band are returned to customers. In contrast, many approved MYRPs have wider dead bands and/or permit utilities to share in surplus earnings beyond the dead band. Some plans do not have an ESM.

  In the event of underearning, the utility must absorb the entirety of any ROE shortfall for a full year, after which it can file for a rate case that does not guarantee the elimination of underearning in a future rate effective year. In contrast, some approved MYRPs have shared underearnings automatically with customers.
- The term of the plan is only three years.
- The Commission, or Public Staff on a motion may, at any time during a plan, conduct reviews, hold hearings, and initiate a proceeding to adjust rates.
- The Commission is afforded considerable discretion over the details of MYRPs.

Regulatory Efficiency

MYRPs should approve the efficiency of regulation and the statutory framework should accomplish this, first and foremost by reducing the frequency of rate cases. Regulatory resources will thereby be freed up to focus more on utility capital expenditure ("capex") proposals, rate designs, and miscellaneous generic issues. This is a notable advantage in a period of rapid change when North Carolina's commission must contend with a swirl of issues. Of course, the magnitude of these benefits will depend on the other filings and processes that are required as part of, or in conjunction with, the PBR plan.

Cost Control Incentives

The Company's cost control incentives would be strengthened by the plan. Under continued cost of service regulation utilities would be free to file rate cases at any time. Given system modernization needs and the current national and state-specific goals to significantly accelerate carbon reductions by 2050, the Duke companies would likely file cases frequently.

The ability of underearning utilities to file a rate case during the plan is a fairly unusual feature of the framework. However, this provision is unlikely to trigger a rate case given the three-year plan period since a utility cannot file until a year of underearnings has been established and the utility is already allowed to file a rate case at the beginning of Year 3 in order to have new rates effective upon the expiration of a plan. Therefore, the only time this provision could be exercised is in Rate Year 2. This provision affords utilities some protection, but since it only allows the utility to file a rate case in Year 2 to have new rates effective for a portion of Year 3, if it underearns in Year 1, it is not likely to have a material, negative impact on the cost control incentive.

We also note that the template only gives utilities the *right* to file a rate case if it underearns in the first year. They would sometimes not file a case even if they are eligible to do so because the situation is expected to be temporary, and it is in their long-term interest to make MYRPs work.[3] There are fairly similar provisions in the approved MYRPs of some other utilities and in the new PBR law in Washington state.[4]

Moreover, there are significant incentives to contain O&M expenses (or "opex") and many kinds of capital expenses since the revenue for these kinds of cost is not linked to the actual costs. Incentives to contain O&M expenses and capital expenses are also fairly balanced under the framework.

Attentiveness to Other Goals

The goals of utility regulation extend beyond ensuring that rates reflect the efficient cost of service. There is, for example, mounting concern around the world at how utility operations affect the

[3] In PEG's experience small underearnings often will not prompt a utility to file a rate case. The decision to file a rate case is based on several factors including the magnitude of the earnings deficiency, forecasted changes in costs or revenues, expectations in changes in the authorized rate of a return resulting from a potential rate case, the ability to seek supplemental revenue through deferrals or cost trackers, and political considerations.

[4] Several generations of MYRPs in Georgia and Florida have included mechanisms with approximately 100 basis point dead bands below the authorized ROE before a utility is allowed to request rate relief for underearning. The utility is required to absorb any underearnings until new rates are set. Florida MYRPs also include a provision allowing interveners to petition for a rate review if the company overearns by more than 100 basis points. Recent legislation in Washington allows utilities the option to file a new MYRP for the 3rd and 4th years of a previously approved MYRP. The Washington law also requires utilities to defer any overearnings that are greater than 50 basis points from the allowed ROE for further determination by the commission.

environment. The template encourages attention to other goals through its revenue decoupling and metric provisions and a lengthy list of criteria for reviewing PBR applications. Other sections of the legislation encourage carbon reductions.

Hard Wiring and Commission Restrictions

Legislation in several states has detailed a particular approach to Altreg and limited Commission discretion to choose a different approach to regulation.[5] The PBR plan provisions detailed in the statutory framework are, in contrast, not set in stone. The legislation directs the Commission to establish implementation rules. The Commission will have some discretion over the design of any plans that are implemented.

[5] See for example, Illinois Public Acts 097-0646 and 102-0662 and Virginia Senate Bill 1349 of 2015.

3. Response to Stakeholder Comments on PBR Rules

3.1. General Intervenor Criticisms of the Statutory Framework

Stakeholders offered a number of controversial general comments about the legislated PBR template. Some salient examples are discussed below.

Framework Overview

The group of four intervenors that includes the North Carolina Justice Center ("NCJC et al.") states the following in their initial comments:

> HB951 missed an opportunity to put North Carolina in the vanguard of states making significant progress on utility regulatory reform.[6]
>
> HB951 maintains traditional COS regulation at the heart of its attempt to create "performance-based regulation."[7]

PEG notes that MYRPs are a popular alternative to traditional cost of service ratemaking ("COSR"), but are still less the rule than the exception in U.S. ratemaking. COSR is the norm, and the most popular alternative to COSR is to address a wider array of costs with trackers and rate riders. Many southern states use formula rate plans, which are tantamount to comprehensive cost trackers, to regulate electric utilities (e.g., Arkansas), gas utilities (e.g., Oklahoma, South Carolina, Tennessee, and Texas) or both (e.g., Alabama, Louisiana, and Mississippi). In Illinois, Maryland, and the District of Columbia, ratemaking systems that are called multiyear rate plans have recently been approved that, due to "fine print" reconciliation provisions, symmetrically true up a utility's revenue to its actual costs. These plans are better described as formula rates. In Ontario and Quebec, larger electric utilities typically operate under "incentive ratemaking" plans that feature an essentially cost of service treatment of capital revenue.

In many jurisdictions, first generation MYRPs take the form of cautious steps away from traditional ratemaking. One reason is that many parties to regulation are, at least in the transition to PBR, reluctant to see a utility's revenue differ very much from its cost of service. Plan designs and rules can evolve as parties gain experience. North Carolina is under no obligation to be in the vanguard of regulatory reform. We agree with the following NCJC et al. statement on pages 9-10 of their comments:

> [W]ith the proper guardrails, carefully targeted performance incentives, and Commission oversight, the legislation may provide some improvement over traditional cost-of-service regulation as practiced in North Carolina.[8]

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[6] North Carolina Docket E-100, Sub 178, NCJC et al., "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," filed November 9, 2021, p. 2.

[7] *Ibid*., p. 9.

[8] North Carolina Justice Center, et. al, op. cit., pp. 9-10.

That would be quite an accomplishment and set the stage for further improvements. Ironically, by calling for strict accounting of differences between the forecasted and actual costs of new capital projects (as discussed further below), some commenters would actually increase the link between rates and actual costs.

Melissa Whited of Synapse Energy Economics ("Synapse") states on page 2 of her comments for the Carolina Utility Customer Association ("CUCA") that:

> [t]he elements set forth in North Carolina's PBR statute, if implemented, constitute a significant departure from both traditional ratemaking and the typical application of MYRP principles.[9]

In reality, a wide range of MYRP provisions have been approved in North America and around the world. Many plans have an unusual feature or two. These features oftentimes address special circumstances, and some are innovations that add to the array of worthwhile precedents.

Cost Forecasts

Synapse and NCJC et al. complain that revenue escalation is based on cost forecasts. For example, Synapse states on page 1 of their comments that:

> the MYRP's annual revenue increases are based on utility cost forecasts, which further erodes the utility's incentives to constrain spending, while also exacerbating information asymmetries between the utility and regulator.[10]

In reality, the role of cost forecasts is fairly limited in the statutory framework. Only the costs of discrete, identifiable capital projects for which the utility requests cost recovery are forecasted. The revenue that compensates utilities for other capital and most O&M expenses would not be based on forecasts. The capital structure and cost of debt appear to be frozen at the levels in Year 1 of the MYRP; hence, the financing costs in Years 2 and 3 of the plan are not adjusted for forecasted changes to the capital structure or cost of debt.

Capex as the Main Determinant of Rates

NCJC et al. argues that "capital investment is 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."[11] This assessment overlooks several key features of the statutory framework. First, the costs of the itemized new capital projects for which the utility seeks cost recovery will constitute only a small percentage of the overall revenue requirement. Second, as we explain in Section A.4 of the Appendix, the revenue growth provisions of many MYRPs are based on capital cost forecasts. This

[9] North Carolina Docket E-100, Sub 178, Melissa Whited, Synapse Energy Economics, Inc., "Implementing PBR with Customer Protections in North Carolina," Prepared on Behalf of the Carolina Utility Customers Association, filed November 9, 2021.

[10] Synapse, op. cit.

[11] North Carolina Justice Center, et. al., op. cit., p. 12.

includes MYRPs in the British "RIIO" ratemaking system. The particular approach to using forecasts of the cost of new plant additions that is detailed in the North Carolina statute obviates the need to explicitly escalate the revenue for most O&M and capital costs. Some examples of MYRPs designed in this way are discussed in Appendix Section A.4. Third, capital costs are not tracked, as in several MYRPs. Fourth, PIMs can encourage DERs and non-wire alternatives to growth-related capex.

Revenue Escalation Using Indexes

NCJC et al. states on p. 7 of their initial comments that:

> an attrition relief mechanism usually takes the form of an index that is independent of a utility's actual costs, that accounts for inflation and recognizes industry-wide changes in productivity.

They further state on page 9 that the PBR template lacks common features of incentive regulation, such as indexed revenue escalation and "a consumer dividend" that creates ratepayer benefits. PEG's experience does not support this assessment. Most MYRPs in the United States have not relied on indexes to escalate revenue. One reason is that rate and revenue cap indexes are difficult to design for vertically integrated electric utilities, such as DEC and DEP. The design of indexed revenue escalators using calculations of industry cost or revenue trends can involve complex and controversial calculations. Revenue escalators that are not based on industry cost trend research typically do not feature stretch factors. Indexed revenue escalators in Australia and Britain are based on capex forecasts.

The COSR Alternative

A table on page 9 of the Synapse report suggests that COSR has moderate cost containment incentives, which are tied to regulatory lag and prudence reviews.[12] This invites the view that MYRPs should not be approved unless they generate incentives that are stronger than moderate. However, we explained in our Berkeley Lab paper that cost containment incentives under COSR depend on the frequency of rate cases.[13] When utilities expect to underearn chronically due to unfavorable business conditions, frequent rate cases ensue that weaken cost containment incentives.

3.2. Proposals for Additional Plan Provisions

HB 951 provides a list of matters that should be addressed in the PBR rules proceeding. This list does not include the establishment of additional mandatory PBR plan provisions. Nonetheless, some parties proposed additional provisions in their initial comments. One problem with these proposals is that the short period available for comments and the lack of discovery and oral testimony in this proceeding does not allow for a full discussion of important plan design issues. Another is that some specific proposals are controversial. Below PEG offers some preliminary responses to parties' comments.

[12] Synapse, op. cit.

[13] Lowry, M.N., Makos, M., Deason, J., and Schwartz, L., op. cit., p. 5.1.

Clawback of Capital Underspends

Synapse, NCJC et al., and the Public Staff ("Public Staff") have proposed that any savings that result from the capital costs of new, approved projects being less than projected levels be passed through to customers. There is some precedent for such "clawbacks" in New York and Minnesota.[14] In Ontario, clawbacks occur in certain "custom" MYRPs but not in most MYRPs.

House Bill 951 does not appear to provide for such clawbacks. Even if they were authorized, the potential pitfalls of such an approach include the following:

- Capex containment incentives would be weakened.
- The statutory framework returns all surplus earnings in excess of 50 basis points to customers. This provides customers with a great deal of protection against underspends.
- The proposal could be implemented too strictly. Projects often are installed a little before or after their anticipated in-service dates. It would be unfair to penalize a utility for short delays while providing no offset for projects that are placed in-service earlier than anticipated. A similar concern arises if utilities must credit customers for any incremental project costs that are lower than forecasted, while absorbing any project costs that are greater than forecasted. The integrity of a capital budgeting process should be assessed based on its overall reasonableness, not the utility's ability to project each in-service date and investment cost with 100 percent accuracy.
- Public Staff's proposed rules require the Company to file a rate adjustment proposal for each capital project that is cancelled or postponed.[15] The same concern stated above applies to postponements. Moreover, this requirement seems administratively burdensome.
- This quest for precision, if implemented equitably, could ultimately devolve into a capital tracker for approved projects.
- While we advise against a clawback, if the Commission nonetheless decides that it wants clawbacks they should be based on the cumulative overall cost of new plant additions, thereby accounting for costs below forecasted levels as well as costs above forecasted levels. In addition, substitute projects should be permitted and subject to a prudence review in the next rate case.

PIMs

Some stakeholders are doubtless anxious to ensure that metrics and PIMs play an important role in the new regulatory system and further certain policy goals, such as decarbonization. This has

[14] See for example, the MYRPs approved in Minnesota PUC Docket GR-15-826 and New York Cases 19-E-0065 and 19-G-0066.

[15] Public Staff's Initial Comments, Appendix A, p.15

prompted some to promote specific areas for PIMs in their initial comments rather than focusing on general rules for developing PIMs without predetermining their focus. For example, NCJC et al. wants to require inclusion of PIMs in six areas as part of any PBR filing: cost efficiency, SAIDI/SAIFI (penalties only), deployment of DERs (rewards only), accelerated achievement of carbon reduction targets (rewards only), improvements in energy efficiency program deployment (rewards only), and low-income affordability/energy burdens.

PEG offers the following response to these comments.

- The Commission must at some point decide in which areas PIMs are needed to strengthen utility performance incentives. We believe that this can be accomplished in the early years of the MYRP implementation in a utility-specific PBR application proceeding.
- The performance areas shortlisted by NCJC et al. are generally reasonable, and some may well be addressed by PIMs in future plans. However, after further reflection by the regulatory community, some of these areas might instead end up being addressed by metrics without financial incentives. The rules for metrics established in this proceeding should not be overly prescriptive. The statute already provides the Commission with 11 suggested and sensible criteria for appraising PBR applications. At most, the rules should provide general guidelines as to the appropriate areas for PIMs. The Commission can then approve PIMs based on the specific circumstances of each utility and each PBR plan.
- Given that the statute authorizing alternative regulation in North Carolina is new, it might be preferable to start with a conservative approach to PIMs — both in terms of their number and their goals. The role of PIMs can then be expanded as the stakeholders and the Commission gain experience.

In addition, Public Staff's proposed rules include the following provisions:

> (3) Each recommended policy goal shall be accompanied by:
>
> a. A clear statement defining and explaining the policy goal;
>
> b. an explanation as to why the goal is appropriate;
>
> c. suggested metrics for measuring success in achieving the goal;
>
> d. a timeline to achieve the policy goal. Any policy goal extending beyond one year must also include incremental annual achievement targets; and
>
> e. supporting analyses, workpapers, modeling, and any other information needed to provide reasonable justification for implementing the policy goal. [16]

and

> (4) One or more clearly defined PIMs that include:

[16] NCUC Docket E-100, Sub 178, "Initial Comments and Proposed Rule of the Public Staff," Appendix A, filed November 9, 2021, p. 4.

a. Identification of one or more policy goals adopted by the Commission pursuant to R8-__(c)(2) or (3) that the PIM targets;

b. A detailed explanation of how the proposed PIM supports or advances the policy goal(s);

c. An estimate of the impact to annual and total revenue requirements (NC retail jurisdiction and customer classes) that would result from implementation of the policy goal;

d. Identifiable and measurable metrics that will be used to assess compliance, including but not limited to projections of costs to be incurred, along with information on how the electric public utility intends to evaluate, measure, and verify compliance or achievement, and the proposed resources (labor, contractors, materials, etc.) the electric public utility plans to use to implement the policy goal;[17]

PEG offers the following comments on these provisions:

First, Public Staff's proposed rules require the utility to estimate the impact of a PIM on annual and total revenue requirements. But this net cost impact will depend on the utility's performance. It is unclear if the Public Staff simply intends to estimate the cost impact if the target is achieved — ignoring the potentially wide variations in net cost assuming worse or better performance.

Second, Public Staff's proposed rules refer to metrics used to assess "compliance." This requirement appears to be based on the assumption that the goal of PIMs will always be compliance with some target or threshold. While PIMs certainly include metrics and targets, the goal of PIMs is not always compliance with a predetermined target; instead, the goal may be the optimization of an initiative or initiatives that can result in achievement levels beyond the target.

Third, the Public Staff's proposed rules for PIMs require both a reward and a penalty. However, in some cases a reward-only or penalty-only PIM might make more sense. For example, in the NERP report, one of the key principles to consider for PIMs was the following:

> 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.[18]

Certain kinds of PIMs that are more experimental in nature, such as beneficial electrification PIMs, tend to be rewards only. PEG believes the Commission should retain the discretion to implement reward-only PIMs.

[17] *Ibid*., p. 11.

[18] NERP Report, p. 20.

NCSEA cautions that existing DSM incentives must be clearly distinguished from PIM incentives established in PBR proceedings. We agree with this observation; there is potential for double-counting.

NCSEA also points out that the statute doesn't prevent stakeholders from proposing performance and tracking metrics. PEG agrees with this position, as long as stakeholders are required to support their proposals in the PBR proceeding by meeting the same criteria that utilities are required to meet.

NCJC et al. specifically proposes a PIM that is based on the non-fuel cost per kWh delivered. PEG disagrees with a PIM based on such a crude cost performance metric. The cost of a utility also depends on other business conditions that include input prices, the number of customers served, and peak demand.

Benchmarking Studies

Synapse recommends that utilities be required to:

> submit a cost benchmarking study using data from the largest group of peer utilities available that are electric-only investor-owned utilities with ownership of generating resources and at least 400,000 customers.[19]

PEG acknowledges that statistical cost benchmark studies (which we pioneered in North American regulation) can be a worthwhile addition to rate regulation. However, these studies are complicated, sometimes controversial, and are not required in most MYRPs. In North America, only Ontario and Massachusetts have made benchmarking a routine feature of proceedings to approve MYRPs.[20]

Plan Termination Provisions

NCJC et al. criticizes the statutorily required three-year term of proposed plans, claiming that this is one of several examples of where the statute "fails to include some of the most important and common features of incentive regulation adopted and under consideration in other states…." However, there are many precedents for MYRPs with terms of three years.[21] Moreover, NCJC et al. attached a *PBR Regulatory Guidance* report by the North Carolina Regulatory Process ("NERP") and urges the Commission to consider the analyses and recommendations in this report. One of the recommendations, found on page 5 of the report, is that "[a] maximum of three years should be the term of an initial MYRP." Consequently, NCJC et al.'s criticism of the three-year term appears to contradict the report it endorses in its comments.

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[19] Synapse, op. cit., p. 11.

[20] In Massachusetts benchmarking was a feature of three out of the four currently approved plans. In Ontario annual benchmarking studies are undertaken to appraise power distributor cost performance. The Massachusetts regulator adopted a similar requirement as part of Massachusetts Electric's current MYRP.

[21] See, for example, the current MYRPs of Georgia Power (Georgia PSC Docket No. 42516), Duke Energy Florida (Florida PSC Docket No. 20210016-EI), and Consolidated Edison (New York Cases 19-E-0065 and 19-G-0066).

CIGFUR argues that if there is nothing to replace the MYRP at the end of the term, rates should revert to the rate year 1 levels (those determined in the rate case for the first plan year). NCSEA stated in related comments that:

> equity requires that customer rates revert to the rates set pursuant to N.C. Gen. Stat. § 62-133 at the termination of the PBR plan period. Both N.C. Gen. Stat. § 62- 133 and § 62-133.16 require that rates are fair to both the utility and to the consumer. N.C. Gen. Stat. § 62-133.16 deviates from the traditional "used and useful" ratemaking paradigm by creating a bargain of sorts between utilities and consumers: the utility will be able to recover costs associated with certain capital investments and the consumer will have policies in place that incent the utility to provide improved performance via PIMs. N.C. Gen. Stat. § 62-133.16(f) makes clear that PIMs expire after 36 months, and thereafter consumers will no longer be receiving their end of the bargain. Therefore, it would be inequitable for the utilities to continue receiving their end of the bargain after 36 months without consumers receiving improved performance, so rates must revert to those set by the Commission pursuant to N.C. Gen. Stat. § 62-133. Reverting to the rates set by the Commission pursuant to N.C. Gen. Stat. § 62-133 would also provide protection for ratepayers, including LMI residential customers.[22]

However, as we discuss in the Appendix, when MYRPs end base rates typically continue at their final-year levels until the Commission approves new rates through a traditional rate case, a new MYRP, or another regulatory proceeding. California and Georgia are examples of jurisdictions that require utilities to file rate cases at or before the end of the MYRP term.[23] Rates set at the outset of a plan would likely not reflect input prices, operating scale, or other cost pressures at the end of the plan. Utilities would be very likely to file rate cases in the last plan year in order to prevent such an outcome.

New Rate Designs

NCJC et al.'s proposed partial rules related to revenue decoupling require:

> any utility applying for a multiyear rate plan to also model and consider new rate designs that reduce or eliminate the fixed charge or that incorporate inclining block rate elements.[24]

PEG observes that the statutorily required decoupling mechanism does encourage rate designs that promote DSM, and reconsideration of rate designs is a good use of the regulatory resources that are freed up by less frequent rate cases. However, there is no statutory basis for requiring specific new designs as part of a PBR Plan. All stakeholders should advocate for whatever rate designs they deem appropriate. The PBR rules should not predetermine the results.

[22] NCSEA, op. cit., p. 32.

[23] California Public Utilities Commission Decision No. 20-01-002 and Georgia Public Service Commission's Order Adopting Settlement Agreement in Docket No. 42516 decided December 17, 2019.

[24] North Carolina Justice Center, et al., op. cit., p. 15.

Authorized ROE

NCJC et al. proposes to lower the authorized ROE for utilities operating under an MYRP, stating the following in their initial comments:

> 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.[25]

PEG believes this recommendation is at best premature. The statute already authorizes the Commission to consider any impact of an MYRP on customer or utility risk when setting the authorized ROE for the term of the MYRP. The statute seems to direct the Commission to evaluate such risk impacts on a case-by-case basis; consequently, there should be no predetermined risk adjustment memorialized in rules. Moreover, it is important to recognize that the statutory framework does not shield the utility from risk for at least the following reasons:

- Test years in North Carolina rate cases are historical.
- Decoupling applies only to residential revenue and does not protect Duke from fluctuations in C&I billing determinants due to recessions, unusual weather, or other factors.
- There are no provisions in the framework to expressly compensate utilities for input price inflation, even though there is mounting concern in the United States about this risk.
- For this and other reasons, there is a real risk that revenue for many O&M expenses and plant additions will be undercompensatory.
- The Commission may render adverse decisions on initial rates, plant additions, or requested revenue deferrals.

Regarding precedent, MYRPs generally do not feature low authorized ROEs even if they include decoupling.[26]

3.3. Implementation Rules

HB 951 likely did direct the Commission to establish rules for mechanisms that are part of the PBR template. In our comments below PEG will identify and respond to some of the parties' initial proposals regarding implementation rules.

[25] North Carolina Justice Center, et. al, op. cit., p. 9.

[26] There are a handful of precedents for an explicit increase in the allowed ROE due to the risks involved with an MYRP.

Revenue Decoupling

NCSEA proposes that utilities demonstrate how decoupling has affected the residential class — including the benefits of increased energy efficiency, the energy burden on LMI customers, the equality of rates among customers in the residential class, and whether rate shock has occurred.

The value of these proposed requirements is dubious.[27] Examining the benefits of increased energy efficiency may be helpful when evaluating the need for decoupling, but has little value when, as in North Carolina, a residential decoupling mechanism is already required by statute. Moreover, any evaluation of either low-income issues or rate shock must consider many other factors of equal or greater importance than revenue decoupling. Only analyses that incorporate all of these factors can allow for a comprehensive assessment.

Earnings Sharing

Public Staff's proposed rules refer to a range of Commission-approved ROEs. PEG notes that such a range was not assumed in the statute — which refers to a single authorized ROE. If a range were approved, the utility should have the right to file a traditional rate case during the MYRP term if its weather-normalized ROE falls below the floor of the range; and the utility should have the obligation to provide refunds to customers only if the weather-normalized ROE is 50 basis points above the ceiling of the range.

PEG also believes that the utility's requirement to document its earnings for the purpose of applying the annual earnings test raises the following questions:

- Will there be a "mini rate case" to evaluate the reasonableness of the utility's financial presentation?
- Is there a standard list of Commission-approved pro forma adjustments utilities may reflect or are required to reflect when reporting earnings?
- Will the schedule for reviewing the annual filing accommodate the required reviews?

3.4. PBR Implementation Proceedings

Both Public Staff and NCSEA propose additional proceedings to implement any PBR plan. Below PEG will offer brief responses to these proposals.

Additional PBR Policy Proceedings

Public Staff recommends on page 3 of their Appendix that a generic docket be established in 2022 and at least every three years thereafter to address policy goals that PIMs proposed in an MYRP

[27] Revenue decoupling on its own does not create an explicit incentive for increased energy efficiency, but rather reduces the utility disincentive to provide energy efficiency programs.

proceeding may target. Proposals would evidently be due April 1 of this year. PEG offers the following observations regarding this proposal:

- PBR in a given jurisdiction is sometimes preceded by lengthy initial generic proceedings, but sometimes is not. Jurisdictions that have opted for such proceedings include Great Britain and Quebec. Examples of jurisdictions that have not taken this path include California, Maine, New York, and Massachusetts.[28] Some jurisdictions (e.g., Hawaii, British Columbia, and Ontario) started PBR without a generic proceeding but held generic proceedings several years later.

- Hawaii's commission considered a new approach to PBR in a multiyear proceeding that included consideration of goals, metrics, PIMs, and other PBR plan provisions.[29] A collaborative developed PIMs that were included in the MYRP proposals of the three Hawaiian Electric utilities.[30] Since the approval of MYRPs for these companies, a collaborative has continued to consider additional PIMs for them. In Minnesota, the Commission approved an MYRP for Xcel Energy and then continued to consider additional PIMs. A large electric utility in Washington state is preparing a rate case and MYRP proposal even though the Commission there is just embarking on a multiyear generic proceeding to consider policies for PIMs and other PBR approaches.

- A proceeding of this kind may last for many months -- or years —and could delay the commencement of MYRPs.[31] The submission of MYRP proposals should not have to wait until such a proceeding is concluded.

- Appropriate PIMs will vary by utility, and views about PIMs may evolve even within the proposed three-year cycle of generic PIM proceedings.

- Utilities and intervenors alike should be free to recommend PIMs not explicitly approved in a generic proceeding.

- The Commission and stakeholders will experience a learning curve with PIMs and may ultimately not need periodic generic proceedings to reconsider PIMs.

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[28] PEG is aware that Massachusetts opened an investigation into the appropriateness of PBR and some high-level commentary in D.P.U. 94-158 prior to energy utilities filing PBR proposals. However, PEG's understanding of that proceeding was that it was similar to North Carolina HB 951 and the current proceeding. Notably, the decision spends one paragraph discussing the need for metrics to appraise the success of incentive mechanisms and only mandated performance indicators for safety, reliability, and service quality. Massachusetts subsequently held generic proceedings to address specific issues including service quality and revenue decoupling. California and New York only investigated PBR after obtaining years of experience evaluating MYRP proposals and their effectiveness. Neither jurisdiction has subsequently held a similar proceeding.

[29] Hawaii PUC Docket No. 2018-0088.

[30] *Id.*

[31] The Minnesota proceeding to consider PIMs for Northern States Power began in 2017 and has continued beyond the MYRP term.

NCSEA proposes that a mandatory PIM proceeding be initiated to determine policy goals and the performance metric system six months before the filing of any PBR plan.[32] Below PEG offers some preliminary comments on this proposal:

- Evaluating utility-specific factors is indeed critical, but that evaluation can be better conducted within the context of the PBR application, where stakeholders can consider all aspects of the plan. Considering utility-specific factors before the filing would be premature.
- In conjunction with other pre-filing requirements and other envisioned processes, the entire PBR process could become unwieldy and protracted under NCSEA's proposal.
- This requirement seems duplicative if the Commission were to also initiate generic policy proceedings, as the Public Staff proposes.

NCJC et al. is seeking a supplemental rulemaking process to continue after the current proceeding to address the complexity of PBR and interplay of PBR with technical conferences on projected transmission and distribution expenditures, the Carbon Reduction Plan, and the Affordability Stakeholder working group.[33] They are seeking a delay in any MYRP filing to late 2022 in order for affordability and the carbon plan processes to be incorporated into the MYRP.[34] This delay is unwarranted.[35] While it is important to establish sound affordability and environmental metrics, and the referenced proceedings are certainly important for achieving this goal, MYRP applications need not be delayed. There are never "perfect" rules that can anticipate every issue. A supplemental rulemaking won't solve that problem, but it may delay progress. Stakeholders and the Commission can incorporate any new information and decisions resulting from other proceedings (including proceedings other than the two NCJC references) into PIMs on an ongoing basis — as the need arises.

Prefiling Requirements

Capital Projects

NCSEA proposes that utilities be required to secure pre-approval of all capital projects for which they seek cost recovery. Specifically, they suggest that the utility file for approval at least six months prior to the application. (In contrast, CIGFUR proposes that the Commission approve capital projects in the PBR proceeding.) NCSEA states the following on page 14 of its comments:

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[32] North Carolina Utilities Commission, Docket E-100, Sub 178, "NCSEA's Initial Comments," filed November 9, 2021, p. 13.

[33] NCJC et al., *op.cit. p*age 4.

[34] NCJC et al., *op.cit.* page 21 and 24.

[35] Under NCJC et al.'s proposal, utilities that are underearning may be in a situation where they would need to file back to back rate cases. The first would address 2022 underearnings, while the second would be needed to request an MYRP. This would increase regulatory cost and be contrary to the recommendations of other parties.

> The Commission's rules governing the authorization of capital investments should examine how the investments are targeted to achieve the PIMs that are set by the Commission in the Policy Consideration Docket, should include information about how the investments are targeted to help achieve the requirements of Section 1 of House Bill 951 (the Carbon Plan), should include information about how the investments support the ownership of solar generation by independent power producers as required by Section 1(2)b. of House Bill 951, should demonstrate how the investments are informed by the Integrated System Operations Planning ("ISOP") process, as has previously been required by the Commission for Duke, and demonstrate how the investments address congestion relief on the grid, as has previously been required by the Commission for Duke.

NCSEA continues on page 16 of its comments:

> Such supporting data should include information about how the investments are targeted to achieve the factors the Commission considers in authorizing a capital investment plan: how the investments are targeted to achieve the PIMs that have been set by the Commission, how the investments are targeted to help achieve the Carbon Plan, how the investments support the ownership of solar generation by independent power producers, how the investments are informed by the ISOP process, and how the investments address congestion relief on the grid.

PEG believes that extensive and compelling evidence on proposed capital projects is a reasonable expectation of stakeholders and will be a key to the success of MYRP proposals in North Carolina. Nonetheless, NCSEA's proposal raises the following concerns:

- Contrary to NCSEA's assertions, the statute seems to expect that the Commission will approve capital projects within the context of the PBR proceeding itself. The fact that the statute uses the past tense ("authorized") when discussing this approval does not preclude such authorization from being secured in the PBR filing. For example, regulatory commissions routinely approve rate designs based on a class cost of service study ("CCOSS") in rate cases without previously approving the CCOSS; both approvals are afforded in the same proceeding.
- NCSEA's proposal is based in part on their assertion on page 13 that "the legislature intended for the Commission to authorize capital investments prior to a utility filing a PBR application." We disagree. The statute permits approval of capital investments within the MYRP proceeding.
- While PEG has not tracked precedents in the U.S. for the prefiling of rate case and MYRP evidence, we are aware of a similar practice only in California. This process was mandatory and required the filing of the entire rate case before the case was officially filed. PEG's

latest review of California regulation found that prefiling was no longer required.[36] In Ontario, PBR plan filings have occasionally been preceded by stakeholder engagement.[37]

- The legislature explicitly calls for utilities to address their T&D capex proposals via a technical conference. Clearly, the legislators carefully considered pre-filing requirements and provided for no pre-approval of capital projects.
- From a policy perspective, it seems sub-optimal to require approval of capital projects before the entirety of a PBR case is filed and vetted. For example, the utility's initiatives aside from capital projects may provide an important context for the capital projects, as could overall rate impacts and the PIMs.
- It seems odd to initiate a proceeding to approve capital investments six months before the application while convening a technical conference to provide information on the same projects two months before the filing date. While NCSEA suggests that the technical conference be incorporated into the capital approval process, it is unclear how that incorporation would be accomplished in a timely and efficient manner.
- The incorporation of a capital approval process into the Carbon Plan prompts additional questions regarding how multiple proceedings can be coordinated in a timely manner.

Technical Conference for T&D Capital Projects

Regarding the technical conference for capital projects, NCSEA and Synapse propose that stakeholders be allowed to conduct discovery related to the utility's presentation. NCSEA observes that it would be "unprecedented" for the Commission to authorize capital investments without allowing the opportunity for discovery.

PEG notes that the 60-day process for the technical conference will allow stakeholders to better understand the utility's T&D investment plans and provide meaningful feedback. As such, the pre-filing technical conference presentation by the utility essentially serves the purpose of discovery. Furthermore, because the statute explicitly provides for stakeholder comment and feedback as part of the technical conference, it gives the utility the opportunity to consider such stakeholder feedback prior to finalizing and filing the PBR application. Nonetheless, technical conferences are usually less formal than contested cases. The introduction of discovery into the technical conference might be difficult to accommodate within the 60-day period and would further appear to be premature when the utility could modify its plan based upon stakeholder feedback.

Public Staff recommends that the utility provide extensive information during the technical conference to justify proposed capital projects. Most of the proposals appear reasonable, with a couple exceptions:

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[36] California Public Utilities Commission Decision 20-01-002.

[37] See, for example, the stakeholder engagement undertaken by Ontario Power Generation prior to the filing of its MYRP proposal in OEB proceeding EB-2016-0152.

- Public Staff again apparently excludes environmental protection as reason for a project.
- Public Staff requires a benefit-cost ("B-C") analysis, which may be difficult for some projects (e.g., it is sometimes difficult to quantify the benefits of projects that improve reliability or offer environmental protections). For some projects it may be difficult to do more than demonstrate that they are the least expensive alternatives for achieving the desired goal. This demonstration is different from a B-C analysis, which typically requires that all significant costs and benefits of an initiative be identified to determine if the initiative is cost-effective.

NCSEA's proposal that the utility demonstrates how each capital investment meets various goals is not unreasonable with a couple caveats:

- Incentives are provided in large part to spur the utility to consider new and better ways to achieve a goal. The utility will not know everything before the filing date. If that were true, there would be no need for incentives; we could just rely on command-and-control.
- Some investments crucial to providing responsible utility service will not fit into the factors that NCSEA lists for supporting capital investments, i.e., carbon reductions, congestion relief, PIMs, Integrated System Operations Planning process, and support of third-party solar.
- Clear directions on how a utility demonstration is made should be developed and implemented in a manner that does not raise regulatory cost unduly.
- It may be better for the utility to provide some of this analysis in the context of the MYRP proceeding.

Filing Requirements

Revenue Requirements

Public Staff's proposed rules would require the utility to submit, as part of its PBR filing, detailed forecasts of costs — by specific cost element — for each year of the MYRP. PEG notes that this information would be useful for setting rates during the term of the MYRP *only* if the statute authorized the use of forecasted test years. But, as explained previously, the statute authorizes forecasts only for the limited purpose of recovering the costs of new, Commission-approved investments; the statute clearly does not authorize the Commission to set rates based on fully forecasted test years. Consequently, these proposed filing requirements would require significant effort while providing little or no practical benefit to the Commission when setting rates. As explained previously, the statute provides for effective MYRPs without the use of fully forecasted test years.

Rate Design

Public Staff proposed filing requirements would require extensive forecasts of load data and revenue, similar to the filing requirements for revenue requirements. Specifically, Public Staff's proposed rules would require submission of a variety of load information by class for each year of the MYRP. It is unclear why Public Staff wants this information, but such load data is usually requested for rate-design purposes. This interpretation appears to be confirmed by the fact that the Public Staff's proposed rules explicitly require a separate CCOSS for each year of the MYRP.

PEG's understanding is that DEC and DEP plan to submit a CCOSS for each year of the MYRP. But the provision of forecasted billing determinants and revenues for each year of the MYRP would be superfluous, since the statute does not authorize fully forecasted test years. In fact, no revenue forecasts are authorized.

Because the statute does not authorize the use of forecasted billing determinants to develop rates for Years 2 and 3, it would be difficult to reconcile rates based on frozen levels of billing determinants with CCOSS and revenue proofs that incorporate projected load data and billing determinants.

This concern with the Public Staff's proposed filing requirements is not trivial; requiring utilities to provide forecasted billing determinants and revenues could significantly increase the time and cost of preparing and evaluating the filing.

Capital Projects

CIGFUR requests that the Companies be required to provide the following:

> An explanation, including all supporting data, of how each and every proposed capital expenditure for which the applicable utility intends to recover costs through an MYRP complies with the "least cost" standard set forth in the "least cost" requirements set forth in N.C. Gen. Stat. § 62-2(3a), and reiterated repeatedly in the recently-enacted House Bill 951, specifically in subsections (1), (2), (2)b., and (4) of Part I, Section 1. S.L. 2021-165;[38]

In House Bill 951, "least cost" was discussed in the context of generation and decarbonization investments. Our understanding is that transmission and distribution investments and expenses are subject to reasonableness and prudency standards. Regardless of the legal standard, it is unclear if a "least cost" standard could be practically and effectively applied to many transmission and distribution investments (or even minor generation projects), as many of these projects are required to comply with certain reliability, customer growth, safety, or environmental regulations.

Incorporation of Stakeholder Feedback

CIGFUR proposes that each PBR application include a statement explaining how the utility incorporated stakeholder feedback in its filing, "including all supporting data."

PEG is unsure of what supporting data is envisioned but believes a narrative should suffice.

[38] CIGFUR Initial Comments, p. 19.

Subsequent Filing Requirements

NCJC et al. proposes four "Subsequent Filing Requirements." Two of these requirements are to file "Proposed Second Year PBR Revenues" and "Proposed Third Year PBR Revenues."

PEG notes that for each year the proposed revenues would be equal to the proposed base revenue requirement. We are unsure why these revenue requirements for Year 2 and Year 3 would not be part of the initial filing. Perhaps NCJC et al. is suggesting that the utility identify revenues in Years 2 and 3 that include all of the various rate adjustments attributable to the PBR Plan. Another possibility is that they anticipate revisions to the capex plan.

Rules for Refiling PBR Plans

CUCA proposes that any refiled PBR application be subject to a process allowing for intervenor discovery and testimony. This process could be time-consuming and administratively burdensome. The Commission can decide if the utility has rectified deficiencies in the initial filing without intervenor testimony. A streamlined process with comments would be more efficient and minimize regulatory cost.

In contrast, CIGFUR proposes that the curing rules not be prescriptive, to preserve Commission flexibility to design a process that reflects the specific curing issues. This proposal seems reasonable.

Limits on Filing

As explained previously, NCJC et al. proposes to prohibit a utility from filing a PBR plan until the Carbon Plan is completed, the Commission can consider the final recommendations of the Affordability Collaborative, and the Commission promulgates supplementary rules. In the meantime, utilities would be able to file only traditional, non-PBR rate cases.

Similarly, NCSEA proposes that "Duke" be prohibited from filing a PBR application until January 1, 2023, so that any capital investments to be approved will be informed by the Carbon Plan. (Apparently, VEPCO would not be so restricted.)

It is unclear when the supplemental rulemaking envisioned by NCJC et al. could be completed, particularly since the carbon reduction and affordability initiatives must be completed before supplemental rules could be promulgated. Regardless, the restrictions that NCJC et al. and NCSEA propose seem contrary to the legislative intent of promulgating rules relatively quickly and allowing for applications to be filed soon afterwards.

Periodic Reports

The Public Staff proposes quarterly filing requirements. PEG has not undertaken a comprehensive review of periodic PBR filing requirements but can offer the following comments.

- The frequency of reporting varies between jurisdictions. For example, Massachusetts Electric is required to provide reports on the PBR plan annually as part of its current MYRP.

Similarly, Georgia Power is only required to file earnings reports annually as part of its current MYRP. By contrast, Florida utilities are required to file earnings reports monthly.[39] Utilities with MYRPs may not be required to report their earnings during the MYRP term.

- The annual review process should not be a mini-rate case. Here are some examples from other jurisdictions as to how an annual review process is undertaken.
    - Under its current MYRP, Georgia Power files its earnings report each March. Staff reviews this report and prepares a summary report a few months later. The Commission issues a decision on earnings in the summer.
    - PS New Hampshire's current MYRP has an annual filing process tied to the review of its plant additions. Staff and the Consumer Advocate have 90 days to review the plant additions and rate adjustment, including an audit by Staff. They have an opportunity to file discovery on the company's plant additions and comment on the prudence of the additions.

NCSEA proposes monthly reporting to help monitor the effectiveness of the PBR plan. PEG believes this reporting could become burdensome for the utility and test the ability of stakeholders to conduct meaningful reviews. Quarterly reporting may make more sense.

3.5. Criteria for Evaluating PBR Applications

Some of the parties' proposed criteria for evaluating PBR plans are controversial and ignore the statutory interpretations of "shall" (required) versus "may" (permissive) language in the statute. Below we provide some examples of these proposals and offers some short responses

CUCA witness Synapse proposes the following criteria:

> Plan is more likely than current regulation to advance the goals of utility cost control, lower rates, and reduced administrative burden.[40]
>
> The benefits of achieving any approved PIMs are likely to outweigh the costs of doing so, and the targets represent measurable improvements over the utility's historical or expected performance.[41]

The first criterion references important touted benefits of MYRPs and worthy goals, but can be difficult to prove. Also, MYRPs would be preferable to COSR even if they were superior based on only one of these criteria and equal based on the others. Satisfying the second criterion would be difficult and, in some cases, cost prohibitive.

Synapse also proposes in comments that utilities be required to demonstrate that their proposed cost increases in Years 2 and 3 of the MYRP do not exceed forecasts of regional public utility

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[39] This provision does not appear to be tied to MYRPs.

[40] Synapse, op. cit., p. 3.

[41] Synapse, op. cit., p. 4.

cost escalation rates.[42] But in the proposed rules attached to these same comments, Synapse appears to treat this regional cost test as only one factor the Commission should *consider* when evaluating MYRPs — not as an absolute requirement.

Regardless of whether the regional cost test is proposed as a requirement or a consideration, such a test is unreasonable for the following reasons:

- The template already includes a reasonable 4% cap on the annual increase in base revenue requirements.
- Capex requirements of utilities sometimes cause their cost trends to deviate from industry trends for several years. This principle has been widely recognized by regulators in Canada and has on many occasions prompted those who use indexed ARMs to sanction supplemental capital revenue for utilities that demonstrate a need.[43]

CUCA proposes that utilities demonstrate that their average customer rates and bills (residential) will be within a reasonable range of peer utilities' rates and bills during and at the conclusion of the plan. This proposal suffers from the following problems:

- Even utilities in the same region can have various advantages and disadvantages that result in rate and bill differences.
- The utility cannot know what other utilities' rates will be at the end of an MYRP plan.
- The utility may be starting at an unfavorable rates and bill position. The MYRP could help improve the utility's relative position, but be rejected because the utility's rates and bills are still higher. Such a rejection might make the rate and bill comparison even worse.

[42] Synapse, op. cit., p. 3.

[43] See, for example, Alberta Utilities Commission Decision 20414-D01-2016.

Appendix

A.1 Traditional Utility Ratemaking and the PBR Alternative

COSR

The traditional cost of service approach to electric utility regulation ("COSR") has the following essential characteristics.

- A revenue requirement is established for the utility in occasional rate cases which reflects the costs that it has recently, is currently, or soon will incur for capital, labor, materials, and services. The retail revenue requirement is reduced by the other operating revenue from miscellaneous non-tariffed services that the utility provides using rate-based assets. The revenue requirement is then allocated between tariffed services. Rates are designed to recover the portion of the revenue requirement which is allocated to each service class. Utilities are typically free to file rate cases as needed to address financial attrition.
- Cost trackers expedite recovery of energy commodity expenses. Balancing accounts are typically used to track unrecovered costs that regulators deem prudent. Recovery of these costs is then typically initiated promptly using rate riders.[44]
- Costs are sometimes deemed imprudent by regulators and disallowed.
- Rate designs are expressly approved by the regulator and may reflect a wide range of considerations that include affordability, cost causation, and appropriate price signals to inform customer usage decisions. Regulators have traditionally favored rate designs with high usage charges that recover a sizable share of utility costs that are fixed in the short run, along with energy commodity costs.

Alternative Regulation

Alternative approaches to rate regulation have included forward test years, lower volumetric charges in rate designs, and expanded use of trackers and riders to address rapidly-growing costs of base-rate inputs. Formula rate plans, which essentially track all costs, are now used in several American states in retail energy utility ratemaking.

The various Altreg approaches can be evaluated using criteria that include regulatory efficiency and the utility performance incentives that they generate. The group of ratemaking approaches with relatively strong incentive properties is called performance-based ratemaking. Some of these approaches also improve regulatory efficiency.

[44] The costs may, alternatively, be treated as a regulatory asset earning interest and considered for inclusion in the revenue requirement in future rate cases.

The PBR Alternative

The term PBR encompasses approaches to regulation designed to strengthen utility incentives to perform well. There are four well-established PBR approaches.

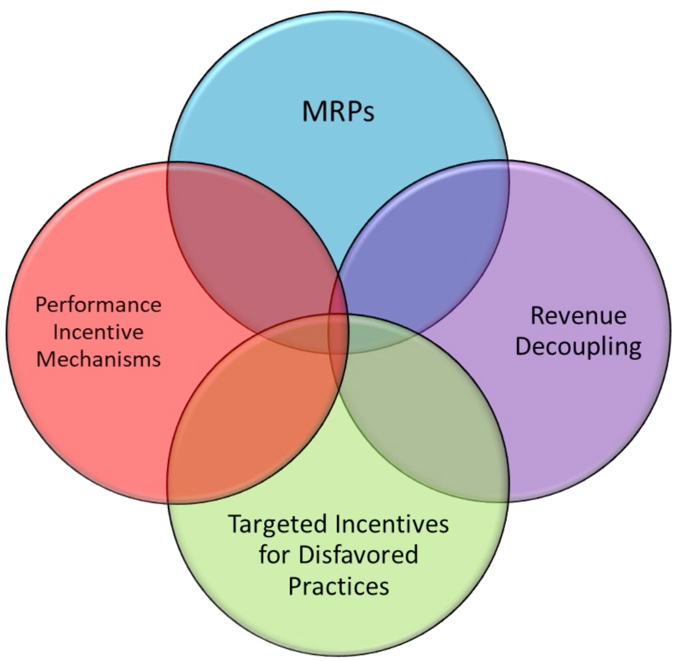
- Relaxation of the link between revenue and system use
- Targeted performance incentive mechanisms
- Special incentives to use disfavored practices (e.g., cost trackers, rate of return premiums, and pilot projects)
- Multiyear rate plans

The various approaches to PBR can be and frequently are combined, as Figure A-1 illustrates. One reason for these combinations is that the individual tools may not satisfactorily address all incentive problems. Another is that some tools can produce undesirable side effects that other PBR tools can counteract.

The stronger incentives provided by PBR can result in improved utility operating efficiency. Some PBR approaches have other benefits that encourage their use. For example, MYRPs can streamline regulation and facilitate greater utility operating flexibility. Revenue decoupling can address some attrition problems and thereby reduce rate case frequency.

Figure A-1

PBR Approaches are Frequently Combined



A.2 Relaxing the Revenue/Usage Link

Introduction

Regulators are increasingly interested in relaxing the link between a utility's revenue and the use of system use by customers. This is a form of PBR because it reduces incentives that utilities may otherwise have to boost the utilization of their systems (aka "throughput").

Two methods are widely used in North America for relaxing the revenue usage link: revenue decoupling and lost revenue adjustment mechanisms ("LRAMs"). We confine our discussion here to the revenue decoupling option.

Revenue Decoupling

Revenue decoupling adjusts a utility's rates mechanistically to help its *actual* revenue track its *allowed* revenue more closely. Most decoupling systems have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism ("RAM"). The RDM tracks variances between actual and allowed revenue and adjusts rates periodically to reduce them. A rate rider is commonly used to draw down these variances by raising or lowering rates.

The RAM escalates allowed base rate revenue to provide relief for cost pressures. The great majority of decoupling systems have some kind of revenue adjustment mechanism since, if allowed revenue is static, the utility will experience financial attrition as its costs rise. Costs of utility base rate inputs typically rise since input prices typically rise and the demand for utility services typically grows.

When utilities do not have multiyear rate plans, revenue adjustment mechanisms approved in the United States typically escalate allowed revenue only for customer growth. While this is helpful, the cost of most U.S. energy utilities is driven more by input price inflation than by customer growth.

The potential benefits of revenue decoupling are numerous. It eliminates the lost-margin disincentive for a wide array of utility initiatives to encourage DSM and DGS, without relying on complicated load impact calculations or rate designs with high fixed charges that could discourage customers from adopting DSM.[45] For example, it reduces the risk from offering customers time-sensitive usage charges that shift loads away from peak demand periods. Decoupling can also compensate utilities for reduced usage-charge revenue due to DER promotion by third parties, such as government agencies. Because it encourages a wide range of DSM initiatives and DGS, environmental intervenors are typically strong supporters of decoupling. Rate cases are less frequent to the extent that utilities are experiencing declining average use. Decoupling also reduces controversy over billing determinants in rate cases with future test years.

Revenue decoupling may not be desirable for all services. For example, some customers may have a demand for utility services that is particularly sensitive to the terms of services. This category includes industrial establishments that have a choice between utilities and consume large amounts of

[45] Load impact calculations may nonetheless be undertaken to help ascertain the effectiveness of DSM programs.

natural gas and/or electricity. Electrification of motor vehicles and space heating can produce positive environmental impacts and permit reductions in rates to other customer classes.

Quite commonly, only revenues from residential and smaller commercial business customers are decoupled. These customers account for a high share of a distributor's base rate revenue, and are often the primary focus of DSM programs.[46] The incentive to promote low carbon electrification of transportation could in principle be accomplished by decoupling only a fraction of the resulting base rate revenues.

States that have recently utilized revenue decoupling for electric and gas utilities are indicated on the maps below in Figures A-2a and A-2b, respectively.[47] In the electric utility industry, it can be seen that decoupling is currently used in 19 jurisdictions. DSM is aggressively encouraged by policymakers in many of these jurisdictions. Decoupling is especially common in the gas distribution industry and is the most widespread means of relaxing the revenue/usage link there. This reflects the fact that gas distributors often experience declining average use and that this has been due chiefly to external forces.

[46] In a multiyear rate plan, service classes excluded from decoupling can be subject to price caps.

[47] The maps reflect the status of decoupling circa March 2021.

Figure A-2a

Recent Electric Revenue Decoupling Precedents in the United States

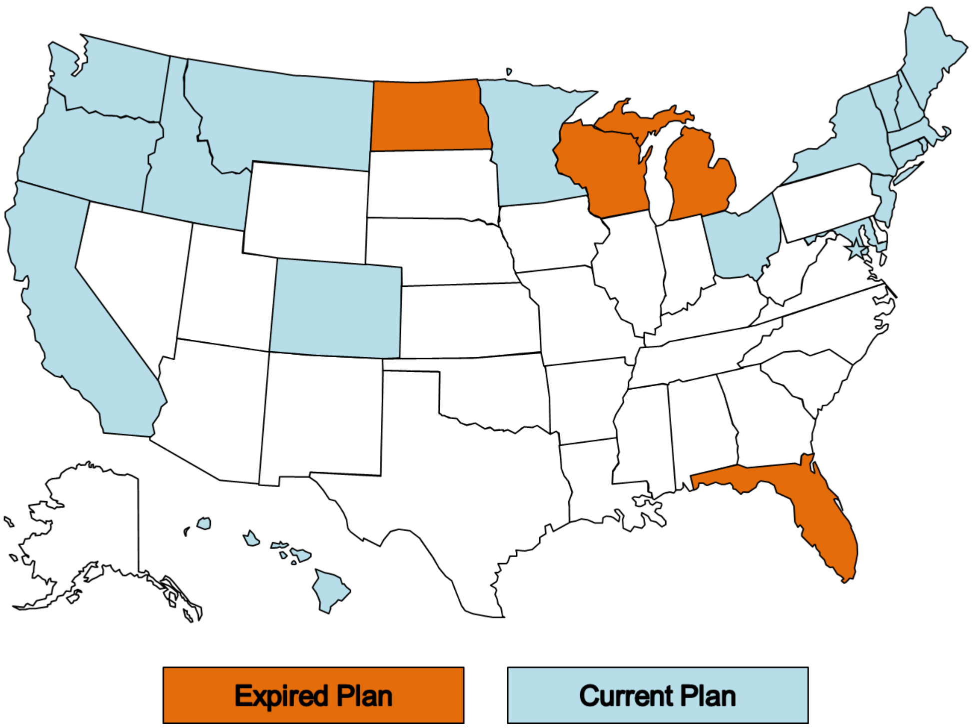
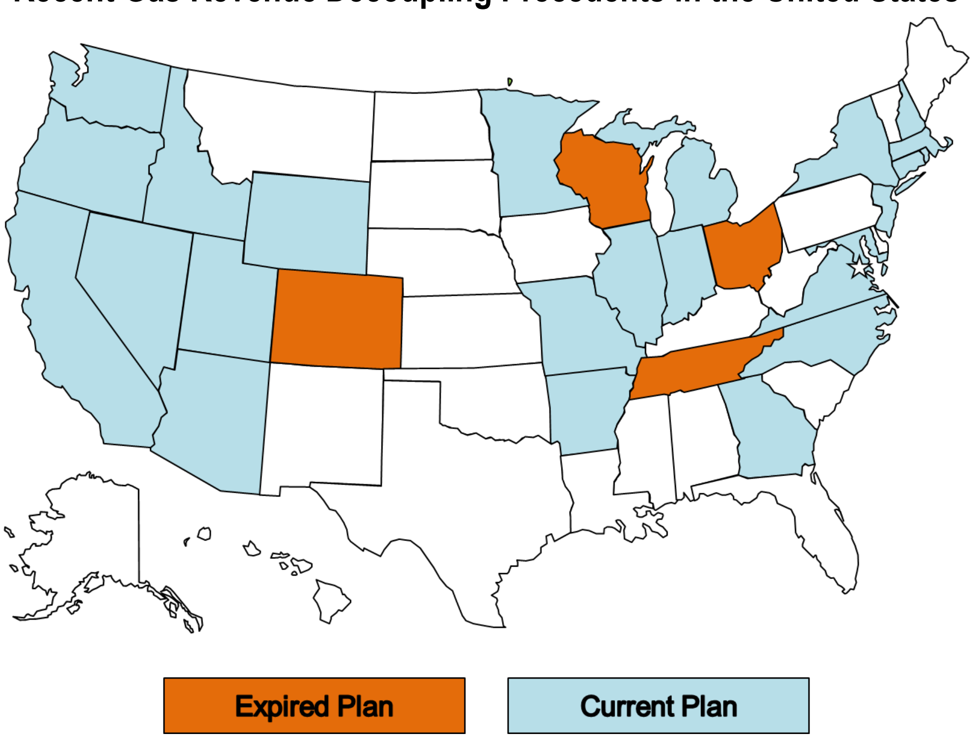


Figure A-2b

Recent Gas Revenue Decoupling Precedents in the United States



A.3 Performance Metric Systems

The Basic Idea

Performance metrics quantify aspects of utility operations (called "outputs in Britain") which matter to customers and the public. A performance metric system is a system for routinely monitoring select metrics and using them in performance appraisals. Target (aka "benchmark") values are usually established for some metrics. Performance can then be measured by comparing a utility's values for these metrics to the targets. This is typically done by taking the differences or ratios between the actual and target values. Performance appraisals can focus on the *level* of a metric or on its *trend*. Scorecards summarizing results for key metrics are often tabulated and may be posted on a publicly-available website or included in customer mailings.

Quantitative performance appraisals using metrics are sometimes used in ratemaking. A performance incentive mechanism or ("PIM") can, for example, link revenue mechanistically to the outcomes of performance appraisals based on metrics. These revenue adjustments can be made in rate cases and/or between rate cases. The following simple mechanism for a hypothetical utility called Atlantic Power is one example of how a PIM can be designed:

$$Revenue\ Adjustment^{Atlantic} = \$ \ x \ (SAIFI^{Atlantic} - SAIFI^{Target}).$$

Here, SAIFI is the performance metric. The SAIDI value attained by Atlantic is compared to a target. The term "$" is the award/penalty rate per unit of deviation from the target. If Atlantic meets the target, then $SAIDI^{Atlantic}$ equals $SAIDI^{Target}$ and the revenue adjustment is zero. If Atlantic performs better than the benchmark, the company may increase its revenue. By the same token, if Atlantic underperforms it must decrease its revenue.

Metrics

Various kinds of metrics are used in ratemaking.

- Outcome (aka output) metrics quantify aspects of utility operations that ultimately matter customers & society. Examples include the cost of service, reliability, and greenhouse gas emissions. Utilities have more freedom to choose best strategy. A focus on what ultimately matters is one advantage of these metrics. Since improvement in performance can typically be achieved by several means, the utility has more freedom to choose between these means.
- A net benefit metric takes the difference between program benefits and costs. A PIM that is based on such a metric can then be designed to share net benefits. However, net benefit metrics tend to be limited to programs with measurable costs and benefits. Program benefits may be controversial.
- Another kind of metric gauges actions and characteristics that tend to promote desirable outcomes. Metrics of this kind are especially useful when other metrics aren't practical.

Examples include an integrated grid planning best practice checklist and the number of customers enrolled in TOU pricing.

Targets that provide a realistic stretch goal for the utility and properly reflect circumstances that it can't control can be difficult to establish. For example, the SAIDI of a utility depends on the extent of system undergrounding, forestation, and the prevalence of severe storms. Improved reliability can be costly. The full set of business conditions that "drive" a metric and their relative importance is often unclear.

Consideration of conditions that influence the *level* of a metric can be sidestepped by making the *trend* in its value the focus of the performance appraisal. A PIM could, for example, focus on the change in a utility's SAIDI from its recent average historical value, and not address whether historical reliability was appropriate. A focus on trends is thus especially convenient when there is not much reason for the target to change over time.

A.4 Multiyear Rate Plans

Multiyear rate plans are complex regulatory systems with essential characteristics and numerous option provisions. We provide an overview of MYRPs in the first section before discussing precedents, MYRP design issues, and MYRP pros and cons in the sections that follow.

The Basic Idea

MYRPs commonly have the following characteristics.

- A moratorium is placed on general rate cases. Rate cases are typically held every three to five years, but plan terms of eight and ten years have been approved.
- There is usually a need for utility revenue to grow between rate cases, as we discussed in the revenue decoupling section. In an MYRP, an attrition relief mechanism ("ARM") permits rates or revenue to grow in the face of such pressures without closely tracking the cost that the utility actually incurs. This externalization of revenue escalation can be accomplished in various ways, as we discuss further below.
- Costs that are difficult to address with the ARM may instead be addressed using trackers and associated rate riders or deferrals. Costs scheduled *in advance* for tracker treatment are sometimes said to be Y factored. Y-factored costs typically include those for energy commodities and frequently also include pension and benefit expenses.
- Revenue adjustments are typically also permitted for hard to foresee events that are largely beyond utility control but affect utility finances. These events are sometimes said to be Z factored. Events commonly eligible for Z factoring include major storms, changes in accounting standards, highway construction programs, and changes in taxes and regulatory policies.

- A performance metric system typically contains PIMs that link revenue to the utility's service quality.

A number of other provisions are sometimes added to MYRPs. These include the following

- When an MYRP features an indexed ARM, provisions are often made to provide supplemental revenue for unusually high capex if this is deemed necessary during the plan term.
- Revenue decoupling and/or lost revenue adjustment mechanisms can reduce the sensitivity of earnings to DERs and demand volatility and reduce concerns about the accuracy of demand projections that have been used in setting rates.
- Many plans have additional performance metrics and PIMs.
- Some plans feature an <u>earnings sharing mechanism</u> ("ESM") that shares surplus or deficit earnings (or both) with customers when the utility's rate of ROE varies from the commission-authorized target.
- <u>Off-ramp mechanisms</u> may permit reconsideration and possible suspension of a plan under pre-specified outcomes such as extreme ROEs.
- Special incentives for underused practices are common in MYRPs. For example, costs of some disfavored inputs may be tracked and/or capitalized.
- Some plans have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services. Provisions like these can help utilities respond to the complex and changing needs of customers and encourage beneficial loads.
- To reduce regulatory cost and bolster incentives to achieve lasting efficiency gains, any updates to rates after the expiration of a plan may not be based entirely on a full traditional general rate case. If a rate case does occur, an <u>efficiency carryover mechanism</u> ("ECM") can permit the utility to keep a share of any lasting cost savings that are reflected in the new revenue requirement.

In practice, the revenue from an energy utility MYRP typically doesn't vary too far from the utility's cost for an extended period. Utilities aren't the only party to regulation that seeks to preserve some cost basis for MYRP rates. For example, consumer groups are customarily wary of letting a utility's revenue rise substantially above its cost for lengthy periods.

MYRP Precedents

MYRPs have been used in North America since the 1980s. They were first used on a large scale for railroads and incumbent telecommunications carriers. Companies in these industries faced significant competitive challenges and complex, changing customer needs that complicated COSR. MYRPs streamlined regulation and afforded companies in both industries more marketing flexibility and a chance to earn superior returns for superior performance. In the United States, both industries achieved rapid productivity growth under MYRPs. Some American states still use MYRPs to regulate incumbent local exchange carriers.[48] The Federal Energy Regulation Commission ("FERC") has used MYRPs for many years to regulate oil pipelines.[49]

MYRPs have also been used on many occasions to regulate retail services of gas and electric utilities.[50] In the United States, California has used these plans since the 1980s, and MYRPs became popular in some northeastern states (e.g., Maine, Massachusetts, and New York) in the 1990s. In addition to MYRPs, several states approved extended rate freezes for electric utilities during their transition to retail competition. Rate freezes have also been part of the ratemaking treatment for utility mergers and acquisitions.

Figure A-3a shows American states that have recently used MYRPs to regulate retail gas and electric services.[51] It can be seen that these plans are now a fairly common alternative to COSR. Energy distributors operate under MYRPs in California, Ohio, New York, and New England. Use of MYRPs has recently spread to VIEUs in diverse states that include Arizona, Florida, Minnesota, Vermont, and Virginia. In addition to North Carolina, a new law authorizes MYRPs in Washington.

Figure A-3b shows that MYRPs are even more widely used to regulate Canadian energy utilities. British Columbia was an early innovator. MYRPs are also common in Alberta, Ontario, and Québec. Overseas, MYRPs are the norm in many English-speaking countries (e.g., Australia, Ireland, New Zealand, and the United Kingdom). Great Britain's RIIO approach to regulation involves MYRPs with elaborate performance metric systems and has drawn considerable interest in other countries. Countries in continental Europe which have used MYRPs to regulate energy utilities include Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania, and Sweden. MYRPs are also common in Latin America.

[48] See, for example, California Public Utilities Commission, Decision Approving Settlement, Case 13-12-005, Decision 15-10-027, October 2015.

[49] See, for example, Federal Energy Regulatory Commission, Order Establishing Index Level, Five-Year Review of the Oil Pipeline Index, Docket RM15-20-000, December 2015.

[50] MYRP precedents for gas and electric utilities have been monitored by the Edison Electric Institute in a series of surveys. See, for example, Lowry, M., Makos, M., and Waschbusch, G., *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute, November 2015.

[51] These maps reflect the status of North American MYRPs ca July 2021.

Figure A-3a

Recent MYRPs for Energy Utilities in American States*

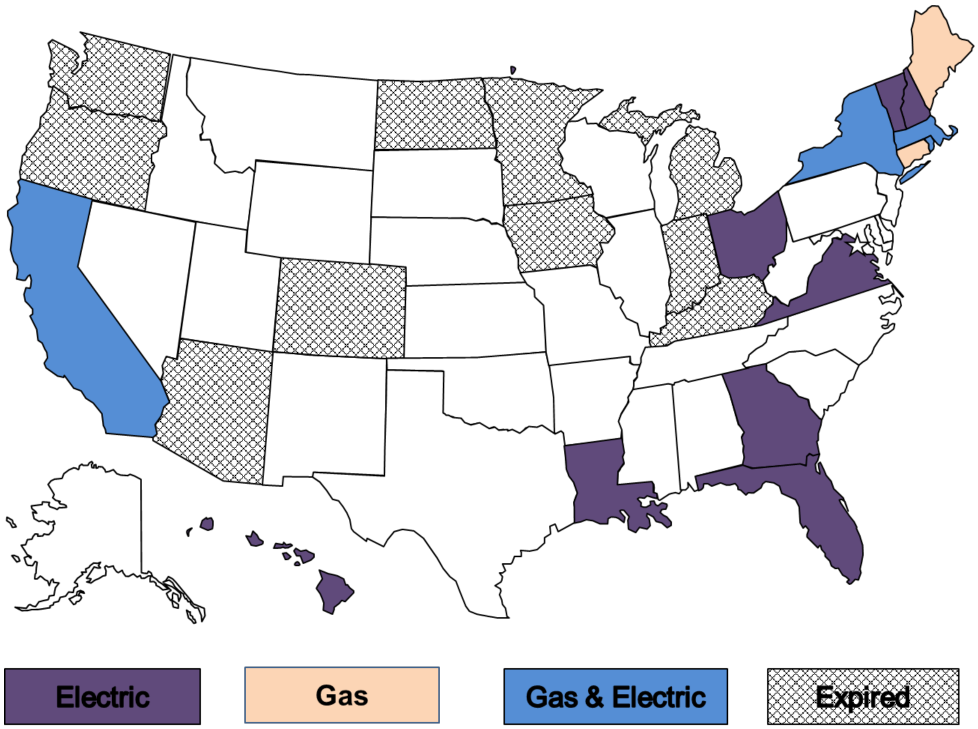
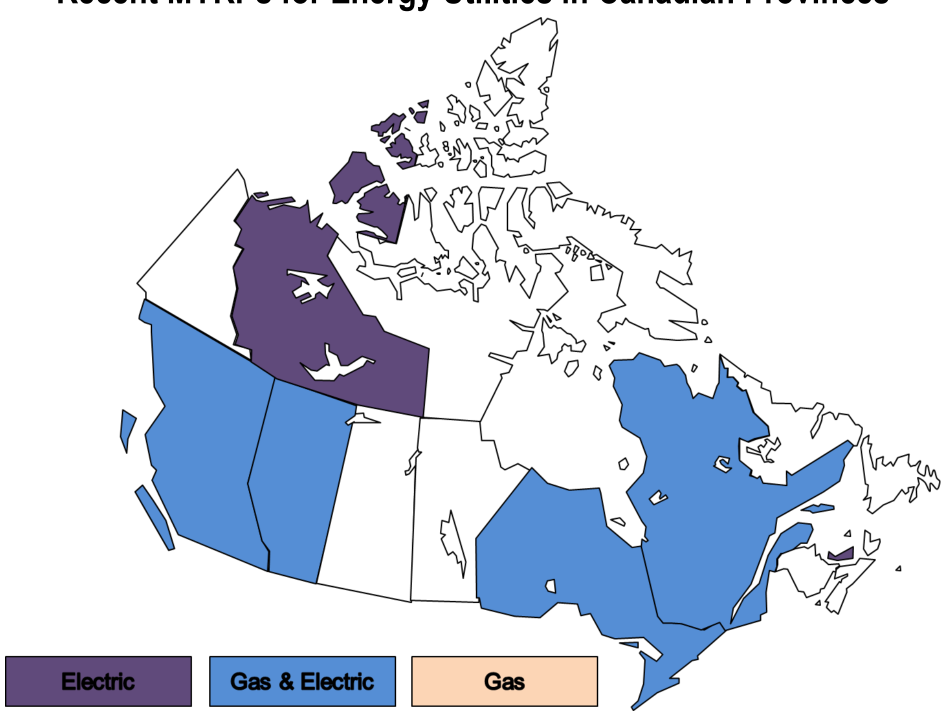


Figure A-3b

Recent MYRPs for Energy Utilities in Canadian Provinces



Attrition Relief Mechanisms

The attrition relief mechanism is one of the most important components of an MYRP. As we have noted, ARMs can substitute for rate cases and cost trackers as a means to adjust rates for trends in input prices, demand, and other external business conditions that affect utility earnings. Utilities can bolster earnings from better performance, and this strengthens performance incentives. In this section we discuss salient issues in ARM design. We first consider how ARMs are used to cap the growth in rates and revenue. Major approaches to ARM design are then discussed at a high level.

Rate Caps vs. Revenue Caps

ARMs can explicitly escalate rates or allowed revenue. Limits on rate growth are sometimes called "price caps." Revenue growth under price caps depends, additionally, on growth in billing determinants. Limits on revenue growth are sometimes called revenue caps.

Price caps have been widely used to regulate industries, such as telecommunications, where it is desirable for utilities to market their services aggressively and promote system use. Growth in system use is generally desirable to the extent that utilities have excess capacity and use of their systems does not involve negative externalities. When rates have high usage charges, price caps make utility earnings more sensitive to the kWh and kW of system use and thereby strengthen utility incentives to encourage greater use.

Under *revenue* caps, the escalator permits growth in allowed revenue (aka the revenue requirement). The allowed revenue yielded by a revenue adjustment mechanism must be converted into rates, and this conversion requires assumptions regarding billing determinants. Rate growth typically does not equal allowed revenue growth since the growth rates of allowed revenue and billing determinants differ.

Revenue caps are often paired with a revenue decoupling mechanism that reduces utility disincentives to embrace DER. However, revenue caps have intuitive appeal with or without decoupling because revenue cap escalators deal with the drivers of *cost* growth, whereas price cap escalators must also reflect the trends in billing determinants.[52] As a consequence, revenue caps are sometimes used even in the absence of decoupling. In the balance of this paper we will often assume for expositional simplicity that growth in allowed *revenue* (rather than *rates*) is capped so that an ARM can be called a *revenue* adjustment mechanism.

Approaches to ARM Design

It is challenging to design ARM that reasonably compensate a utility for growing cost pressures without linking revenue growth to the utility's actual cost growth. Several well-established approaches to ARM design accomplish this. Most can be used, with modifications, to escalate rates or revenues.

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[52] If cost is growing by 2%, for example, and billing determinants are growing by 1% on average, rates need rise only 1%.

Forecasted ARMs

A forecasted ARM is based primarily on multi-year cost forecasts, which are sometimes called proposals. A revenue cap requires a forecast of the (net) cost of service. A price cap requires, additionally, a forecast of billing determinants.

In the United States, a revenue adjustment mechanism based on forecasts typically increases revenue by a certain predetermined percentage in each year of the plan (e.g., 4% in 2021, 5% in 2022, and 3% in 2023).

Apart from such inflation adjustments, and any earnings sharing mechanism that the plan may include, there is typically no adjustment to rates during the plan if the actual cost incurred differs from the forecast. This approach to ARM design might therefore generate strong cost containment incentives despite the use of forecasts.

Forecasts are the most common basis for ARM design in MYRPs of American energy utilities. They are, for example, currently used by electric utilities in California and New York. Ofgem's use of forecasts in ARM design is sometimes called the "building block" approach since the revenue requirement is built up from forecasts of component costs.

Indexed ARMs

The indexing approach to ARM design is based primarily on industry cost trend research. In this research, cost trends are usually decomposed into input price, productivity, and output trends using indexes. Controversy is common concerning cost trend research in a proceeding to approve an indexed ARM. Most utility productivity research to date has focused on gas and electric power distributors.

California, Maine, and Massachusetts were early adopters of indexed ARMs in retail energy utility regulation. ARMs based chiefly on index research are now used more widely to regulate utilities in Canada than in the United States.

Hybrid ARMs

"Hybrid" approaches to ARM design use a mix of index research and cost forecasts. A popular hybrid approach in the United States involves separate treatment of the revenue (or rates) that compensate utilities for their O&M and capital costs. Indexes address O&M expenses while forecasts address capital cost.

The hybrid approach to ARM design that is popular in North America was pioneered in California in the 1980s. This approach has been found to be adaptable to the diverse cost trajectories of California's gas and electric utilities and has been used before and since the restructuring of the electric power industry.

Rate Freezes with Supplemental Capex Funding

Some MYRPs feature a rate freeze in which the ARM provides no automatic rate escalation during the plan. Revenue growth then depends on growth in billing determinants and any costs there are tracked.

Rate freezes are compensatory for utilities when the growth in the costs addressed by these rates matches the growth in their billing determinants. Such favorable operating conditions have occurred over the years under special circumstances. However, favorable circumstances like these are less common today. Inflation is currently brisk, billing determinant growth has slowed, and some utilities need high capex.

Rate freezes have nonetheless recently been approved for several U.S. electric utilities. These are typically vertically integrated utilities that need a few large plant additions. Provided that a few costs that are growing are tracked or accorded a forecasting treatment, they do not need any further rate escalation for several years.

The annual cost of plant additions during an MYRP can be added to allowed revenue on a gross or net basis. If added on a gross basis, no account is taken of the depreciation of older plant. This depreciation is then available to fund growth of O&M expenses and the cost of any untracked plant additions. This approach to ARM design has been used by VIEUs in Arizona, Colorado, Florida, Georgia, Louisiana, and Virginia. Here are some further details of ARMs that combine a rate freeze with a capex revenue bump.

- An ARM for PS New Hampshire took the form of predetermined "stairstep" rate increases.[53] Escalation in the years of the plan was based on plant additions. For each annual rate change a prudence review was undertaken.[54] A tracker to address costs associated with capital additions and O&M expenses for a reliability program was approved alongside this ARM. A similar ARM was approved for PS of New Hampshire in 2020 in a successor MYRP.[55]
- Arizona Public Service has had two MYRPs that featured a rate freeze and a capex revenue bump.[56] These ARMs froze base rates but allowed supplemental funding for various generation and transmission projects. For example, the first MYRP provided supplemental funding for the purchase of part of a large generating facility, environmental improvement

[53] New Hampshire Public Utilities Commission (2010), Order No. 25,123 in DE 09-035. This kind of ARM was approved for Unitil Energy Systems in New Hampshire PUC Case DE 10-055.

[54] This was due to a provision in New Hampshire statutes requiring that return on plant is not permitted in base rates prior to a Commission finding that the plant was prudent, used, and useful.

[55] New Hampshire Public Utilities Commission (2020), Order No. 26,433 in DE 19-057.

[56] Arizona Corporation Commission, In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Develop Such Return, Docket No. E-01345A-11-0224, Decision 73183, May 24, 2012.

projects, and incremental renewable generation.[57] Transmission services were accorded tracker treatment.

- Florida's electric utilities have had several generations of MYRPs, some of which have had ARMs that took the form of rate freezes with capex revenue bumps.[58] These ARMs freeze base rates, but allow utilities to request supplemental funding for selected projects, primarily related to generation. The recently approved MYRP for Tampa Electric, for example, features an initial base rate increase, followed by a base rate freeze. Supplemental revenue for specific projects including generation additions, system hardening, and environmental costs is funded by trackers. The provisions of the MYRP also allow Tampa Electric to request recovery of "costs that are (a) of a type which traditionally or historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) incremental costs not currently recovered in base rates which the Legislature expressly requires shall be clause recoverable."[59]

- Georgia Power has operated under a series of MYRPs for years, at least one of which had only allowed escalation for the cost new generating facilities in base rates with supplemental funding for capex and other costs.[60] Trackers for environmental costs, the costs of new nuclear generating facilities, DSM expenses, and franchise fees provided supplemental revenue.

Plan Termination Provisions

Plan termination provisions are one of the more important issues in MYRP design. The MYRP may include a provision requiring a rate filing near the end of the plan term.[61] Successor rates are often reset in a general rate case, and this typically occurs in the last year of the plan. This option passes all benefits of any long run cost savings achieved during the plan to customers. A true up to cost is also welcomed if poor plan design had caused marked earnings surpluses or deficits.

The downsides of scheduling rate cases in advance are several and include the following.

- This option involves relatively high regulatory cost.

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[57] Arizona Corporation Commission, In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Develop Such Return, Docket No. E-01345A-11-0224, Decision 73183, May 24, 2012.

[58] Florida Public Service Commission, In re: Petition for increase in rates by Florida Power & Light Company. Order No. PSC-13-0023-S-EI, Docket No. 120015-EI, January 14, 2013.

[59] Florida Public Service Commission Order No. PSC-2021-0423-S-EI Attachment A, p. 28.

[60] Georgia Public Service Commission Docket 31958.

[61] MYRPs in California and for Georgia Power typically include a requirement to file a rate case including an MYRP prior to the expiration of the plan.

- Performance incentives are weakened. The incentive to realize longer-term gains is known to attenuate in the later years of an MYRP. This occurs because utilities would in those years incur the upfront costs of performance-improving initiatives but receive few (or none) of the benefits that result.
- Marketing flexibility is complicated.
- Scheduled rate cases can provide perverse incentives to utilities. Utilities may be incented to defer certain costs so that they are high in the test year for new rates and/or ask for supplemental revenue in the out years of the new plan.

Several alternatives to scheduled rate cases have been devised that can mitigate these problems. If a plan does not contain a requirement for a rate case, typically rates will continue at the same level until new rates are approved by the regulator.[62] The MYRP may also continue certain provisions beyond the plan term, such as revenue decoupling, certain cost trackers, certain reporting requirements, and the earnings sharing mechanism.[63]

Plan extensions are also possible for MYRPs. One option is to provide the company with an option to unilaterally extend the plan for a preset period of time (e.g., 1-2 years). Another option is to allow the utility to request an extension of the existing plan.[64] Unless prohibited by statute, parties usually retain the option to negotiate a plan extension.

MYRP Proceedings

A proceeding to approve an MYRP often includes a conventional rate application to establish the revenue requirement for the first plan year. The advantage of this approach is that the parties to the proceeding can consider the initial rates and rate escalation as a "package deal." However, the rate effective year following a rate case provides sufficient time for a proceeding to establish a multiyear plan that escalates the rates in succeeding years.

In many proceedings to establish MYRPs the utility files the first plan proposal. If an indexed ARM is proposed, this filing will include a report on cost trend research. Other parties then provide commentary on the utility's proposal and counterproposals. It is common for either the Commission or consumer groups to sponsor a productivity counter-study. Some proceedings are fully litigated, but many result in a negotiated settlement between the parties.

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[62] In some cases, rates will need to be adjusted after the plan expires to account for the wind down of earnings sharing mechanisms, revenue decoupling, or cost trackers.

[63] Massachusetts achieved this by approving revenue decoupling and service quality performance incentive mechanisms independent of the MYRP approval. Consolidated Edison's service quality PIMs, as approved for their current MYRP, will remain in effect until the regulator decides to change them.

[64] PacifiCorp has requested numerous extensions of its MYRPs in California. The most recent request for an extension was approved in California Public Utilities Commission Decision 21-01-006.

At the outset of MYRP ratemaking, or where a common approach to MYRP design is sought for multiple utilities, a generic proceeding is often convened that is independent of the rate case process. This approach affords parties the time for a more in-depth consideration of PBR issues. Collaborative discussions are common.

Earnings Sharing Mechanisms and Off-Ramps

Some MYRPs include explicit controls on the earnings utilities can achieve. Two approaches to earnings control are common: earnings sharing mechanisms and off-ramp mechanisms. These approaches can be used separately or in combination.

Earnings Sharing Mechanisms

The Basic Idea

ESMs share surplus and/or deficit earnings between the utility and its customers. Such earnings arise when a utility's ROE deviates from its commission-approved target. An earnings surplus, for example, is earnings that cause the actual ROE to exceed its target.

Numerous decisions must be made in the design of an ESM. For example, allocations of earnings variances may also differ with the magnitude of the variances. Small variances (e.g., less than 100 basis points) are often not shared with customers. This provision is often called a "dead band." Beyond the dead band there may be one or more bands in which earnings are shared in different proportions between customers and the company. An ESM may also include earnings caps and/or floors, beyond which the utility will return further incremental earnings surpluses to customers or recover further incremental deficits. A simpler approach is to share all earnings variances by the same proportion.

Here's an example of an ESM with a dead band and multiple sharing bands. Imagine that an ESM is established that allows for a dead band of +/- 50 basis points around the target ROE, followed by an even split of the earnings between +/-50 and +/-150 basis points from the allowed ROE, and beyond these bands 75% of the earnings variance is retained by the customers. Given this ESM structure and assuming an allowed ROE of 10%, the company will not share any earnings corresponding to a 9.5 - 10.5% ROE. The company will retain 50% of earnings variances (positive or negative) in the 8.5 – 9.5% or 10.5 - 11.5% range, and 25% of variances outside of this range.

The symmetry of sharing provisions must also be addressed. ESMs need not be symmetrical. For example, they can share only earnings surpluses or deficits. Even if an ESM shares both surpluses and deficits, the sharing provisions for these can differ.

An additional decision to be made in ESM design is the way in which customers share surplus earnings. Most plans include provisions for immediate rate adjustments, while others allow the customers' share of surplus earnings to be used to reduce the balances of regulatory assets or to fund special efforts. For example, the most recently expired MYRP of Central Maine Power featured an ESM in which the customers' share of surplus earnings was used to help fund improvements to the distribution system, up to a $25 million cap. Amounts in excess of the cap were to be refunded to customers.

Another decision is the definition of earnings eligible for sharing. Most ESMs define earnings as a company's actual earnings. However, an ESM included in Northern States Power's MYRP in North Dakota adjusted earnings for the effects of weather before any sharing occurs.

Precedents for ESMs

ESMs are featured in roughly half of current US and Canadian MYRPs. While some ESMs share both surplus and deficit earnings, most share only surplus earnings.[65] This maintains an incentive for companies to become more efficient to avoid underearning. Dead bands are a common feature of ESMs. Dead bands are used in situations where the company shares earnings surpluses, earnings deficits, or both.

Off-ramps

Off-ramp mechanisms allow MYRPs to be reconsidered before their expiration if certain events occur during the plan. The qualifying events typically involve extreme ROEs but may instead involve other considerations such as unusual inflation or reliability events. The rules for what happens following a qualifying off-ramp event vary. A formal proceeding to reconsider plan terms may be mandatory or at the commission's discretion. Reconsideration may be limited to a revision of plan terms but may also include the possibility of a new rate case.

We have not performed a comprehensive survey of off-ramp mechanisms, but provide here a few recent examples. One can be found in the recent MYRP of MidAmerican Energy in Iowa. The plan has an off-ramp with two specific triggers. First, if the company projects that its ROE would be less than 10% in any year of the MYRP term, any party can file a rate case. Second, MidAmerican can change its rates if ordered to do so by the regulator. Another example is Florida Power & Light's current MYRP which has an off-ramp allowing for a rate review if the actual ROE varies by more than 100 basis points from the allowed level. As a third example, Enbridge Gas Distribution in the Canadian province of Ontario had an off-ramp that allowed for a review of the MYRP if the actual ROE, adjusted for the effects of weather, varies by more than 300 basis points from the allowed ROE in a single year.

A.5 Glossary of Terms

<u>Attrition Relief Mechanism ("ARM")</u>: A common component of multiyear rate plans that automatically adjusts rates or revenues to address utility cost pressures without closely tracking the utility's *own* cost. Methods used to design ARMs include forecasts and indexation to quantifiable business conditions such as inflation and customer growth.

[65] A few ESMs have been approved that share only earnings deficits.

Base Rates: Base rates recover costs that are not otherwise recovered through trackers, riders, or deferral mechanisms. The costs recovered through base rates vary from utility to utility. However, base rates almost always collect most capital and labor expenses.

Capex: Capital expenditures.

Cost of Service Regulation ("COSR"): The traditional North American approach to utility regulation that resets rates in occasional rate cases to recover the cost of its service that regulators deem prudent.

Cost Tracker: A mechanism providing expedited recovery of targeted costs that are approved by regulators. A tracker is an account of costs that are eligible for recovery. These allowances are then typically recovered via rate riders. Tracker treatment was traditionally limited to costs that are large, volatile, and largely beyond the control of the utility. In more recent years, trackers have been used to address energy efficiency expenses, rapidly rising costs, and costs that are difficult to address by other means in MYRPs.

Distributed Energy Resources ("DERs"): Technologies, services and practices that can improve efficiency or generate, manage or store energy on the customer side of the meter. DERs can include energy efficiency, demand response, distributed generation, energy management systems, batteries and more. Plug-in electric vehicles are considered as part of distributed storage. DERs can be implemented by utilities, customers, third-party vendors or combinations thereof.

Earnings Sharing Mechanism ("ESM"): An ESM automatically shares surplus or deficit earnings, (or both), between utilities and customers, which result when the rate of return on equity deviates significantly from its commission-approved target. ESMs often have dead bands in which earnings variances aren't shared.

Lost Revenue Adjustment Mechanism ("LRAM"): A ratemaking mechanism that compensates utilities for the estimated base revenue that is lost from specific causes such as their demand-side management programs and distributed generation. Requires estimates of load impacts.

Marketing/Pricing Flexibility: Flexibility afforded to utilities to fashion rates and other terms of service in selected markets. Typically accomplished via light-handed regulation of rates and services with certain attributes. Services that have been deemed eligible for flexibility include optional tariffs for standard services, optional value-added (aka discretionary) services, and services to competitive markets. Price floors sometimes established for eligible services to discourage predation and cross-subsidization.

Multi-Year Rate Plan ("MYRP"): A common approach to PBR that typically features a multiyear rate case moratorium, an attrition relief mechanism, and several PIMs.

Off-Ramp Mechanism: An MYRP provision that permits suspension of a multiyear rate plan under pre-specified conditions (e.g., persistent, extreme ROEs).

Ofgem: British Office of Gas and Electricity Markets, the regulator of gas and electric utilities in the United Kingdom.

Performance-Based Regulation ("PBR"): An approach to regulation designed to strengthen utility performance incentives.

Performance Incentive Mechanism ("PIM"): A mechanism consisting of metrics, targets, and financial incentives (rewards and/or penalties) designed to strengthen performance incentives in targeted areas such as service quality and the embrace of DERs.

Productivity: The ratio of outputs to inputs is a rough measure of operating efficiency that controls for impact of input prices and operating scale on cost. Productivity may be measured for all inputs or just for O&M or capital inputs.

Rate Base: The net (depreciated) value of utility investment used to provide service, including working capital.

Rate Case: A proceeding, usually before a state regulatory commission, to reset rates that involves a review of the utility's cost and the resetting of rates to recover the revenue requirement. These proceedings may also consider other issues such as rate designs.

Rate Case Moratorium: A set period of time between rate cases designed to reduce regulatory cost and strengthen utility performance incentives. Electricity prices (or revenues) are generally capped during this period, with the exception of cost trackers.

Rate Rider: An explicit mechanism outlined on tariff sheets to allow a utility to receive rate adjustments between rate cases.

Return on Equity ("ROE"): The rate of return on the value of equity capital invested.

Revenue Adjustment Mechanism ("RAM"): A mechanism for escalating allowed revenue between rate cases. These mechanisms are common in multiyear rate plans and are also typically combined with revenue decoupling in regulatory systems that lack such plans.

Revenue Cap Index: A formula that typically includes an inflation index which is used to escalate allowed revenue in multiyear rate plans.

Revenue Decoupling: A mechanism for relaxing the link between a utility's revenue and use of its system which makes periodic rate adjustments to ensure that actual revenue closely tracks allowed revenue. A companion revenue adjustment mechanism typically escalates allowed revenue between rate cases.

Revenue Requirement: The annual revenue that the utility is entitled to collect. The amount is periodically recalculated in rate cases and may be escalated by other mechanisms (e.g., cost trackers and ARMs) between rate cases. It is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base less other operating revenues.

RIIO: The British approach to PBR. The acronym stands for Revenues = Incentives + Innovation + Outputs. RIIO involves MYRPs that include relatively long rate case moratoria (currently eight years), a forecast-based attrition relief mechanism, and an extensive and innovative set of PIMs.

Statistical Benchmarking: The use of statistics on the operations of other utilities to appraise utility performance. In North American regulation, methods commonly used in statistical cost benchmarking include unit cost and productivity metrics and econometric models.

Test Year: A specific period in which a utility's costs and billing determinants are considered in a rate case to establish new rates. Some states use a historical test year and adjust billing determinants and costs for known and measurable changes. Other states use a fully forecasted test year that considers other possible changes.

Throughput Incentive: Under traditional regulation, utilities can increase revenues by increasing sales between rate cases. Increased sales will in turn result in increased profits for the utility, because the marginal cost of providing additional service is typically well below the rate per unit of use.

A.6 About PEG

Pacific Economics Group Research LLC ("PEG") is an economic consulting firm based in Madison, Wisconsin. We are best known for our work in the field of energy utility economics. PBR and statistical research on the performance of energy utilities are company specialties. Our personnel, which include several Ph.D. economists, have over 90 person years of experience in these fields, which share a foundation in economics and statistics.

The University of Wisconsin in Madison ("UW"), renowned for its economics programs, has trained most of our staff. We periodically write articles on our work in respected professional journals. Our practice is multinational and has to date involved projects in twelve countries. Work for mix of utilities, regulators, government agencies, and consumer groups has given us a reputation for objectivity and dedication to good regulation.

PBR

PEG personnel have been active in the PBR field since 1989. Our PBR services include consultation, PBR plan design, expert witness testimony, and research on related empirical issues like utility cost performance and input price and productivity trends. We maintain an international library of PBR decisions.

Our personnel have been North America's leading MYRP consultants for decades. Indexed ARMs with X factors based on input price and productivity research have been used in several jurisdictions around the world. PEG personnel have done more than fifty energy utility X factor studies and published several papers on this research in professional journals. PEG has also done a number of projects that address the use of metrics and PIMs in regulation.

Altreg White Papers and Surveys

PEG personnel are also recognized as experts on other alternatives to traditional cost of service regulation ("Altreg"), which include capital cost trackers, formula rates, attrition allowances, and forward test years. We routinely survey and analyze Altreg precedents and periodically summarize our

Altreg research and analysis in polished white papers. For example, we have prepared three papers surveying PBR and other Altreg trends and precedents for the Edison Electric Institute ("EEI"). In 2015 we completed a multiclient study on PBR which was organized by EEI.

Other Altreg Experience

PEG personnel are also recognized as experts on other alternatives to traditional cost of service regulation ("Altreg"), which include capital cost trackers, formula rates, attrition allowances, and forward test years.

Recent PBR Projects

The ongoing vitality of our PBR practice is also indicated by the following projects and publications that we have undertaken in the last five years (dating back to 2016).

- In 2016 and 2017, Dr. Lowry co-authored two influential white papers on PBR for Lawrence Berkeley National Laboratory. The first considered the role that PIMs and multiyear rate plans can play in a high distributed energy resources future. The second was an in-depth look at MYRPs. Berkeley Lab has also funded presentations by Dr. Lowry about PBR in meetings across the country.
- Dr. Lowry testified in support of MYRPs proposed by Public Service of Colorado for both its gas and electric services.
- Dr. Lowry testified for Northern States Power in Minnesota on the need to add PIMs to the company's recently-approved MYRP.
- Dr. Lowry has provided the Ontario Energy Board with research and testimony on productivity trends, benchmarking, and MYRP design in several recent proceedings, one of which is ongoing. These filings have considered PBR for power transmission and distribution, hydroelectric generation, and gas distribution.
- PEG has also recently done benchmarking and MYRP design work for Green Mountain Power. Our work included a presentation on PBR at the state capital.
- Dr. Lowry has played a prominent role in the development of PBR in Québec. He recently prepared a power transmission productivity and benchmarking study as part of an ongoing Régie de l'énergie proceeding.
- PEG has advised the Hawaiian Electric companies on PBR for more than twenty years. Dr. Lowry recently provided them with research and testimony for their next-generation PBR plan.
- For British Columbia's utilities commission, PEG prepared a white paper last year on PBR and its possible application to BC Hydro, a large, vertically-integrated electric utility.

- Recent articles that Dr. Lowry wrote about PBR include "Revenue Decoupling at 40, Venerable PBR Tool Goes National," which appeared in the April issue of *Public Utilities Fortnightly,* "Four Common Myths About Performance-based Regulation," in the April 27, 2021 *Utility Dive,* and "PBR and Climate Change," in July's *Climate and Energy.* An article, "Escalating Power Distributor O&M Revenue," on our recent research to develop a mechanism for escalating O&M revenue of power distributors appeared in the July issue of the *Electricity Journal.*

- PEG is currently helping Puget Sound Energy develop MYRPs for its gas and electric services. Dr. Lowry led a collaborative process to discuss metrics and PIMs for the proposal. He is currently preparing expert witness testimony in this case.

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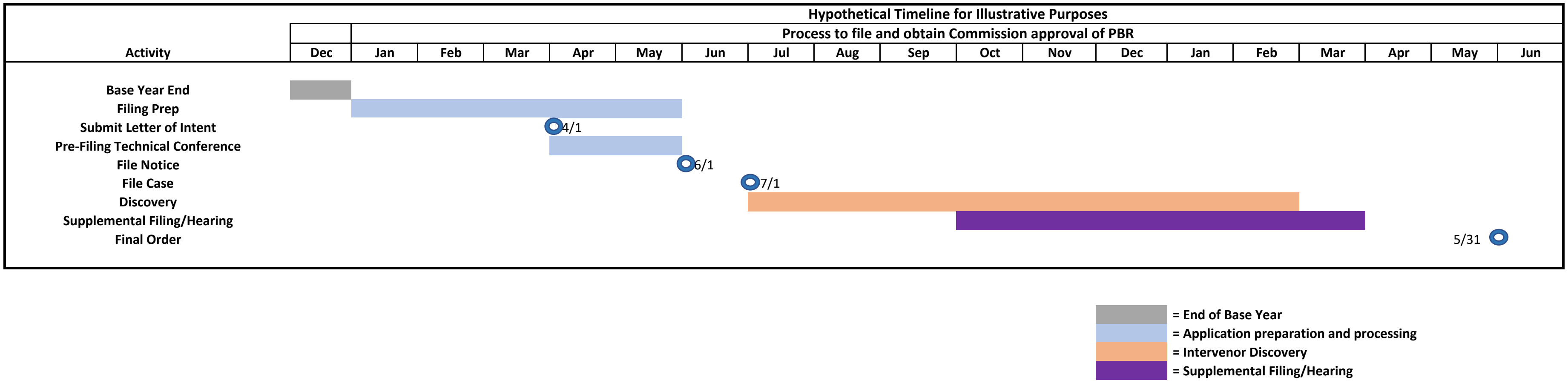
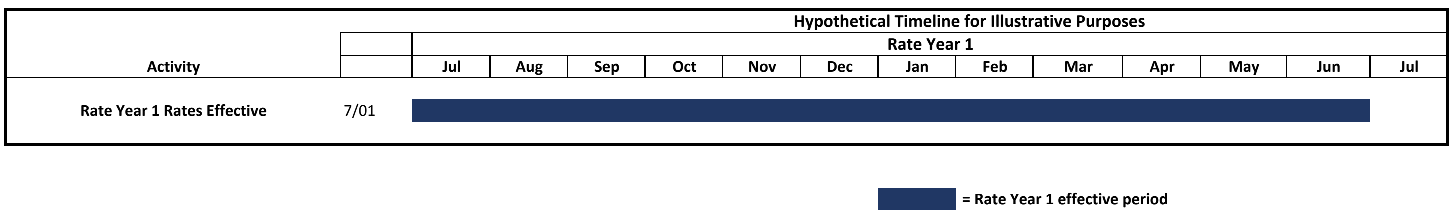
Docket No. E-100, Sub 178





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Hypothetical Timeline for Illustrative Purposes

Rate Year 2 (Jul, Aug, Sep, Oct, Nov, Dec, Jan, Feb, Mar, Apr, May, Jun, Jul)

Activity	
Rate Year 2 Rates Effective	7/01
File Annual Decoupling Rider Calculation Adjustment for Year 1	8/15
Public Staff Verification of Decoupling Rider Rates Adjustment	
Decoupling Order Issued	8/27
Decoupling Rider Rate Adjustment Year 1	9/01
Commission Intiates Annual ESM and PIMs Review	8/31
Annual ESM and PIM(s) Report Filing Rate Year 1	9/30
ESM and PIM(s) Staff Review	
ESM and PIM(s) Company Reply	12/31
ESM and PIM(s) Order Issued	3/27
ESM and PIM(s) Rates Adjustment Year 1	7/1

= Rate Year 2 effective period
= Public Staff Verification
= Decoupling Rider Rates Effective
= Public Staff Review
= ESM and PIM(s) Rates Effective

Hypothetical Timeline for Illustrative Purposes

Rate Year 3 (Jul, Aug, Sep, Oct, Nov, Dec, Jan, Feb, Mar, Apr, May, Jun, Jul)

Activity	
Rate Year 3 Effective	7/01
File Application for Next Case (if applicable)	7/01
Annual Decoupling Rider Calculation Adjustment Year 2	8/15
Public Staff Verification of Decoupling Rider Rates Adjustment	
Decoupling Order Issued	8/27
Decoupling Rider Rate Adjustment Year 2	9/01
Decoupling Rider Rate Adjustment Year 1	
Commission Intiates Annual ESM and PIMs Review	8/31
Annual ESM and PIM(s) Report Filing Rate Year 2	9/30
ESM and PIM(s) Staff Review	
ESM and PIM(s) Company Reply	12/31
EMS and PIM(s) Order Issued	3/27
ESM and PIM(s) Rates Adjustment Year 2	7/01
ESM and PIM(s) Rates Adjustment Year 1	

= Rate Year 3 effective period
= Public Staff Verification
= Decoupling Rider Rates Effective
= Public Staff Review
= ESM and PIM(s) Rates Effective

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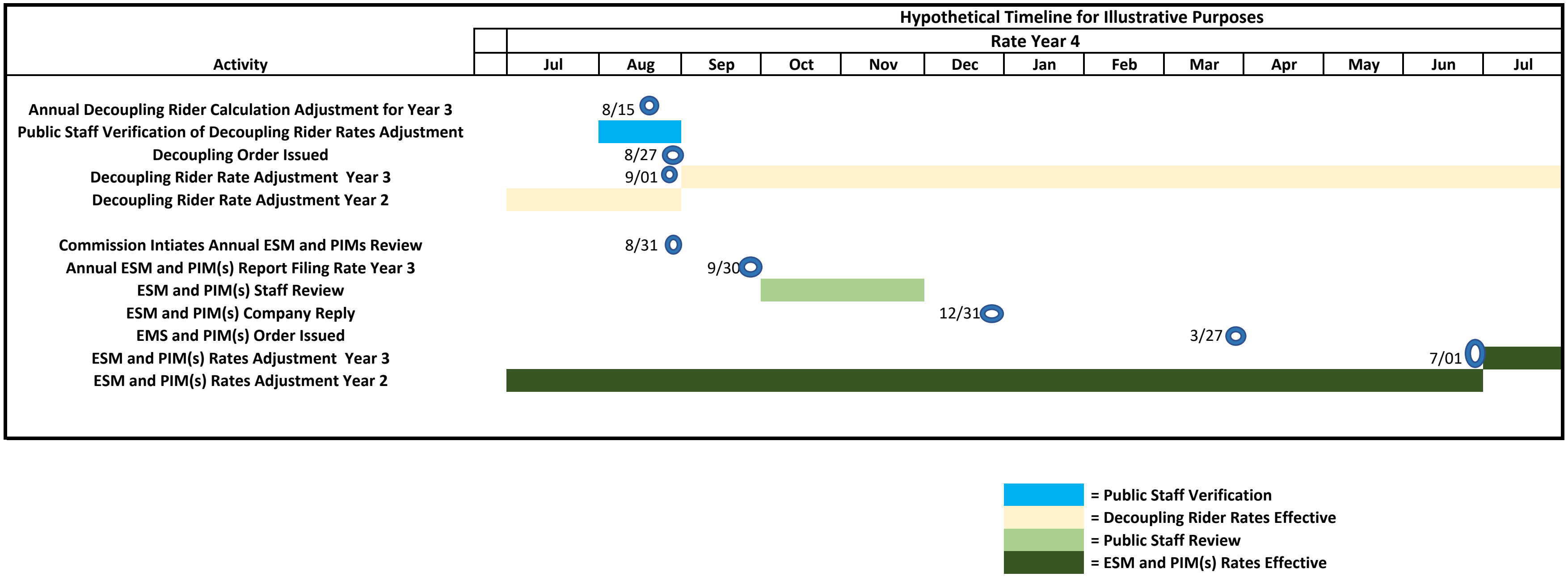

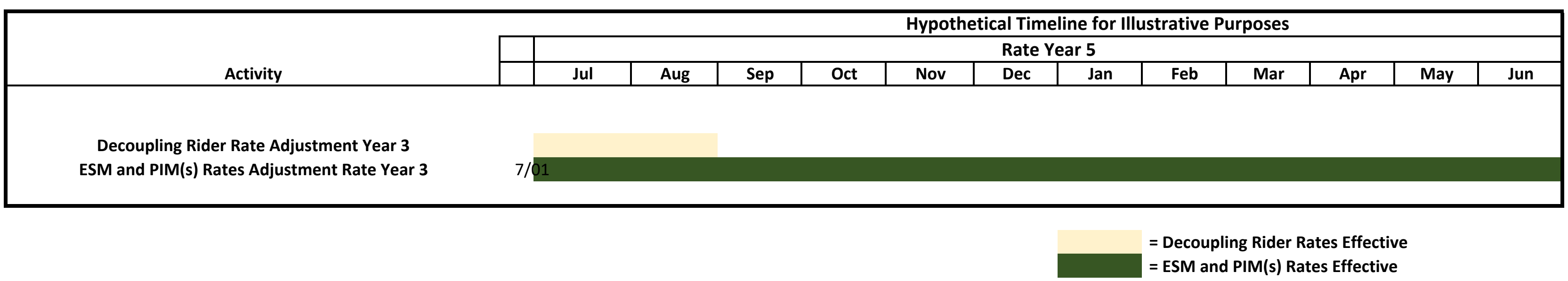

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Reply Comments, in Docket No. E-100, Sub 178, has been served by electronic mail, hand delivery, or by depositing a copy in the United States mail, postage prepaid, properly addressed to parties of record.

This the 17th day of December, 2021.

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