STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

In the matter of

Public Service of New Hampshire d/b/a Eversource Energy

Docket No. DE 19-057

Petition for Permanent Rate Increase

DIRECT TESTIMONY

OF

Ron Nelson
Senior Manager
Strategen Consulting
On Behalf of the Office of the Consumer Advocate

December 20, 2019

Table of Contents

Appendix

Appendix REN-1	Ron Nelson Resume Summary

Schedules

Schedule REN-1	OCA 2-060
Schedule REN-2	OCA TS 3-007
Schedule REN-3	OCA 7-003
Schedule REN-4	OCA 7-001A - Attachment
Schedule REN-5	OCA 7-002E, tab “Att. OCA 7-002E, Pg. 680” in Attachment
Schedule REN-6	OCA 7-004
Schedule REN-7	OCA 8-053
Schedule REN-8	OCA TS 3-002
Schedule REN-9	OCA TS 3-003
Schedule REN-10	OCA 7-012
Schedule REN-11	OCA 7-010
Schedule REN-12	OCA 7-009
Schedule REN-13	Docket No. DE 19-064, Request No. Staff 9-17.
Schedule REN-14	OCA 2-054

I. INTRODUCTION

Q. Please state your name, business address and occupation.

A. My name is Ron Nelson. I am a Senior Manager with Strategen Consulting. My business address is Suite 400, 2150 Allston Way, Berkeley, California 94704.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Office of the Consumer Advocate.

Q. Please describe your formal education and professional experience.

A. Currently, I am a Senior Manager at Strategen Consulting. The Strategen team is nationally recognized for its thought leadership and deep expertise in rate design, renewable program development, grid modernization, and new grid technologies including distributed and centralized renewable energy, energy storage, smart grid technologies, and electric vehicles. During my time at Strategen, I have worked with numerous consumer advocates on issues related to cost of service modeling, rate design, grid modernization, and performance-based regulation ("PBR").

Before joining Strategen in early 2018, I worked for the Minnesota Attorney General's Office for almost five years, where I led the Office's work on cost of service, rate design, renewable energy program design, performance-based regulation, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in Agriculture and Resource Economics, and a Bachelor of

Arts in Environmental Economics and a Minor in Mathematics from Western Washington University.

Q. Have you testified in similar regulatory proceedings previously?

A. Yes. I have testified in Minnesota in nine separate rate case proceedings on issues related to cost of service modeling, revenue apportionment, rate design, renewable program development, tariff analysis, fuel clause structure, multi-year rate plans ("MYRPs"), performance metrics, performance incentive mechanisms ("PIMs"), decoupling, and the utility business model.

I have also testified in three rate case proceedings in Oklahoma, two proceedings in Illinois, and one rate case in Ohio. The issues covered in these proceedings include formula rates, decoupling, distributed energy resource ("DER") compensation, and smart inverter specifications.

I have also assisted with testimonies and regulatory comments in Washington D.C., Maryland, Minnesota, Massachusetts, California, and North Carolina. The issues covered in these proceedings include electric vehicle rate design and infrastructure, cost-benefit analysis, community-based solar programs, integrated resource planning, energy storage integration, and DER interconnection.

A summary of my resume is attached as Appendix REN-1.

Q. Do you have other relevant experience related to evaluating PSNH's proposals in this case?

A. Yes. During my time at the Minnesota Attorney General's Office, I worked on many PBR-related issues and proceedings. Specifically, I worked on proceedings that covered revenue decoupling, MYRPs, rate riders, grid modernization, performance metrics, cost of service modeling, rate design, and PIMs.

Additionally, I acted as an advisor to the Hawai'i Public Utilities Commission ("PUC") for Phase 1 of its primary PBR docket – "Instituting a Proceeding to Investigate Performance-Based Regulation," Docket No. 2018-0088. In this general docket, the Hawai'i PUC is holistically examining the overall regulatory framework to explore how PBR might be used to increase the efficiencies of utilities in the state.

Q. Have you previously provided testimony before the New Hampshire Public Utilities Commission ("PUC" or "Commission")?

A. Yes. I recently submitted direct testimony in DE 19-064, the Granite State Electric Company d/b/a Liberty Utilities rate case.

II. PURPOSE AND RECOMMENDATIONS

Q. What is the purpose of your testimony?

A. I am testifying on the regulatory framework changes that the Company has proposed through step-year rate adjustments. I am also testifying on revenue decoupling, the Allocated Cost of Service Study ("ACOSS"), the Marginal Cost of Service Study ("MCOSS"), revenue apportionment, and rate design.

Q. How is your testimony organized?

A. My testimony is organized into several additional sections and a conclusion: Section III discusses the implication of the Company's proposed regulatory framework changes; Section IV discusses why the Company's lost revenue adjustment mechanism ("LRAM") should be replaced with a symmetrical revenue decoupling mechanism; Section V describes and analyzes the ACOSS; Section VI describes and analyzes the MCOSS; Section VII provides my recommendations for revenue apportionment; Section VIII provides my analysis and recommendations related to residential rate design; and, finally, Section IX concludes my testimony.

Q. What are your recommendations regarding the Company's multiple step-year rate adjustments proposals?

A. I recommend that the Commission reject all step-year adjustments beyond 2019.

Creating a multi-year rate plan ("MYRP") is a significant regulatory change that requires additional safeguards for ratepayers. An MYRP is not necessarily an inappropriate regulatory tool, but implementing such a significant change as a piecemeal reform would not yield the requisite balance between the interests of shareholders and those of ratepayers.[1]

Q. What are your recommendations regarding the Company's LRAM?

A. I recommend that the Commission reject PSNH's proposal to continue utilizing its LRAM. The LRAM is effectively a one-sided decoupling mechanism. Instead, I

[1] *See* "Next-Generation Performance-Based Regulation: Primer—Essential Elements of Design and Implementation," Clean Energy Ministerial and Regulatory Assistance Project (April 2018).

recommend that the Commission adopt a symmetric revenue decoupling mechanism in place of the LRAM.

To create an equitable decoupling regime, I also recommend several reasonable commitments be made by the Company to complement the revenue decoupling mechanism. First, the Company should specify a timeline for analyzing and, when cost-effective, implementing Conservation Voltage Reduction ("CVR"). Second, the Company should specify a timeline for updating DER interconnection standards. Finally, the Company should be required to provide additional specificity related to advanced rate designs.

Q. What are your recommendations regarding the Company's allocated cost of service study?

A. I have three recommendations related to the ACOSS. First, the Commission should use the results of the basic customer ACOSS to inform revenue apportionment. Second, the basic customer ACOSS should also be used to inform rate design. Finally, the Commission should require the Company to continue providing an ACOSS, as it provides useful information for revenue apportionment and rate design.

Q. What are your recommendations regarding the Company's marginal cost of service study?

A. For this case, I recommend that the Commission not rely on PSNH's MCOSS for revenue apportionment or rate design decisions.

In future rate cases, if the Commission chooses to rely on cost studies guided directly by the Company, I recommend these cost of service studies be relied upon as directional indicators as opposed to point estimates. The Commission should weigh policy factors heavily when apportioning revenue and designing rates.

If the Commission wishes to rely more heavily on MCOSS, I recommend that more transparency be required. Improved transparency could be accomplished through a stakeholder process or a process that uses independent contractors that are directed by Staff or the OCA. Lastly, I recommend that the Commission incorporate lessons learned from its locational value of DER project into utility MCOSS.

Q. What are your recommendations regarding the Company's proposed revenue apportionment?

A. I recommend that the Commission adopt my revenue apportionment proposal displayed in Table 4.

Q. What are your recommendations regarding the Company's rate design proposals?

A. I recommend that the Commission reduce the residential customer charge to $11.

III. ALTERNATIVE REGULATION: MYRP

Q. What is the purpose of this section of your testimony?

A. The purpose of this section of my testimony is to respond to the Company's proposals for modifying the regulatory structure in New Hampshire. Specifically, I address the Company's proposal to change rates beyond the 2019 step year and explain why it is necessary to reject rate changes beyond the 2019 step-year adjustment.

Q. Please describe the Company's proposal for step adjustments.

A. The Company is proposing four years of step adjustments to recover revenue requirements associated with incremental capital investments and certain Operations and Maintenance ("O&M") costs.[2] The proposed revenue requirement of the proposed step adjustments includes depreciation expense, property taxes, and a return on rate base.[3] The rate base investments include investments outlined in the Company's base capital plan.[4] Additionally, the Company included enterprise IT projects and anticipated union wage increases in the O&M costs.[5]

Q. What does the Company claim is the purpose of the step adjustments?

A. The Company mentions at least three reasons for proposing the step adjustments. First, the step adjustments will reduce regulatory lag.[6] Second, the Company claims that they will reduce the frequency, and therefore the expense, of rate cases.[7] Lastly, the Company claims that "the proposed step adjustments meet a

[2] *See* Witnesses Chung and Dixon Testimony, Bates 152.
[3] *See* Witnesses Chung and Dixon Testimony, Bates 154.
[4] *See* Witnesses Purington and Lajoie Testimony, Bates 427-428.
[5] *See* Witnesses Chung and Dixon Testimony, Bates 154.
[6] *See* Witnesses Chung and Dixon Testimony, Bates 153.
[7] *See* Witnesses Chung and Dixon Testimony, Bates 153.

requirement contained in prevailing New Hampshire law as espoused by the Supreme Court."[8]

Q. What is your general impression of PSNH's proposal for step adjustments?

A. The step adjustments will create a regulatory framework that exacerbates many of the shortcomings of traditional cost of service regulation. Simply stated, approving the step adjustments will create an imbalance that favors shareholders over utility customers unless implemented as a part of a comprehensive overhaul of the regulatory regime to which the utility is subject.

Q. Can step adjustments be implemented in a way that creates benefits for ratepayers?

A. Not based on the information provided by PSNH in this case. Other states are making attempts to more comprehensively integrate step adjustments, more commonly known as multi-year rate plans ("MYRPs"), into regulatory frameworks based on performance based regulation ("PBR").[9] With thoughtful and resource-intensive regulatory reforms, it may be possible to create a regulatory structure that is more efficient with an MYRP. Without thoughtful implementation, however, MYRPs shift risk to ratepayers and benefit utilities and their shareholders.

---

[8] *See* Schedule REN-1.
[9] Examples include Minnesota and Hawai'i.

MYRPs are integrated as part of PBR framework in many jurisdictions because they often include additional regulatory mechanisms meant to address the long list of shortcomings and perverse incentives associated with unstructured MYRP proposals, such as that put forth by Eversource. PBR addresses the shortcomings and perverse incentives of traditional cost of service regulation by creating a comprehensive MYRP structure that better aligns utility incentives with that of its ratepayers and measures utility performance related to achieving key state policy goals.

Q. How is your response to PSNH's MYRP proposal organized?

A. I respond to PSNH's step adjustment proposal throughout the rest of this section. I begin by rebutting the superficial benefits and legal claims made by the Company. I continue, in Section III.B, by discussing the intensive processes that other states are undergoing to implement step adjustments effectively – more commonly referred to as multi-year rate plans in other jurisdictions – to protect consumers from the perverse economic incentives that are created with unstructured MYRPs. In Section III.C, I discuss components of PBR frameworks that are used to protect consumers when utilizing MYRPs. Finally, in Section III.D, I discuss specific shortcomings associated with PSNH's proposal and structural issues present in New Hampshire that should be addressed before an MYRP is approved.

A. PSNH's Support for Step Adjustments is Insufficient

Q. Do you think the benefits that the Company highlighted will provide significant benefits to ratepayers?

A. No. The Company's proposed step adjustments will not provide benefits greater than the associated costs. In fact, the Company's claimed benefits may create more harm than good for ratepayers. For example, regulatory lag can be beneficial in many cases because it provides the utility with an incentive to control costs. Additionally, while rate cases are expensive and time consuming, they provide regulators and stakeholders an important, holistic review of the utility's finances and an opportunity to make tariff changes.

Q. Please explain the Company's argument that approving step-year adjustments is required by New Hampshire law.

A. The Company claims that step adjustments are necessary to:

> provide the Company with a reasonable opportunity to earn its allowed rate of return on significant investments that are necessary to continue to safely and reliably serve customer and prevent erosion of earnings (i.e., attrition) after permanent rates go into effect.[10]

In response to a discovery request, the Company supported its claim with a Supreme Court ruling that states "[i]f the existence of attrition can be established

[10] *See* Witnesses Chung and Dixon Testimony, Bates 153, lines 13-15.

by the company the commission should evaluate the impact of this factor on the earnings of the utility and make an appropriate allowance for it."[11]

Q. Do you agree with the Company's legal argument?

A. While I am not a lawyer, no. The Company is misinterpreting and misapplying previous legal rulings and orders.

First, the Company acknowledged that the New Hampshire Supreme Court stated that "[i]f the existence of attrition can be established by the company the commission should evaluate the impact of this factor on the earnings of the utility and **make an appropriate allowance for it**."[12] However, the Court stated that the Commission should evaluate attrition and make an appropriate allowance for it; the Supreme Court did not prescribe step-year rate increases beyond an electric utility's test year as a solution to attrition.

Second, in PSNH's most recent rate case, the Commission made it clear that the reasonableness of step adjustments would be revisited. Specifically, the Commission stated: "We also note that though this is not designated as a 'pilot' or similar Program … the limited term of the settlement agreement effectively renders it a short-term program."[13] Furthermore, the Commission tied the approval of the step-year adjustments to the utility's need to spend on its Reliability Enhancement Program

[11] *See* Schedule REN-1.
[12] New England Tel. & Tel. Co. v. State, 113 N.H. 92, 97 (1973). Emphasis added.
[13] *See* Order No. 25, 123 (June 28, 2010) in DE 09-035 at 32.

("REP").[14] The reasoning used by the Commission did not explicitly tie the approval of a legal requirement to approving step adjustments in the presence of attrition. Quite to the contrary, the Commission noted that it was approving a "short-term program" and that it was partially based on the need to achieve a policy goal (i.e., reliability improvements associated with REP spending).[15]

Third, the Company does not acknowledge that it sought a rate case six years after its last step adjustment. Given that six years passed with no rate case, it is unclear whether attrition is a problem. And if it is a problem, it is unclear whether step adjustments are the solution. As noted by the New Hampshire Supreme Court, the Commission need only "make an appropriate allowance" when the utility meets its burden of demonstrating that attrition is an issue, which could include a myriad of ratemaking tools.[16]

Lastly, the Commission is not bound by its own precedents, and the previous Commission orders cited by PSNH simply indicate that in some previous rate cases the Commission has approved step increases, usually when there is a settlement agreement and the case is uncontested. No Commission precedent requires the current Commission to approve step increases – and the standard is "just and reasonable," not "plenary indemnification."[17]

[14] *See* Order No. 25, 123 (June 28, 2010) in DE 09-035 at 33.
[15] *See* Order No. 25, 123 (June 28, 2010) in DE 09-035 at 33.
[16] New England Tel. & Tel. Co. v. State, 113 N.H. 92, 97 (1973).
[17] *Appeal of PSNH*, 130 N.H. 748, 755 (1988) (Souter, J.).

Q. Please comment on the MYRPs that have previously been approved by the Commission.

A. The MYRPs that have been approved by the Commission have not been complemented by the PBR ratepayer protections necessary for efficient implementation. This may partly be a product of most, if not all, of the approved MYRPs being part of settlement agreements. I am not aware of testimony in those proceedings that provided a comprehensive critique of MYRP implementation, as I provide below. Therefore, the Commission now has additional information to consider when determining the reasonableness of the MYRP proposed in this case. Additionally, other commissions have initially approved MYRPs and then opened proceedings to reevaluate their structure and purpose.[18]

In Minnesota and Hawai'i, MYRPs were reevaluated because regulators were not satisfied with utility performance under unstructured MYRPs.[19] These reevaluations have been focused on getting the regulated utilities to commit to achieving state policy goals and measuring their performance, in other words incorporating PBR. In exchange, utilities in these states will receive improved revenue recovery options and potentially additional financial incentives.

[18] Commissions in both Hawai'i and Minnesota approved MYRPs then later opened up dockets on their structure. *See* Hawai'i PUC Docket No. 2018-0088 and MN PUC Docket No. 17-401.
[19] *See* Hawai'i PUC Docket No. 2018-0088 and MN PUC Docket No. 17-401.

Furthermore, while the Commission granted PSNH an MYRP in its last rate case, it also made clear that the concept would be revisited. Specifically, the Commission stated:

> We also note that though this is not designated as a "pilot" or similar program … the limited term of the settlement agreement effectively renders it a short-term program. We find this limitation important because a great deal may change during the term of the settlement agreement and it may be advisable to revise or eliminate items such as this in the future.[20]

The Commission's previous order not only makes clear that step adjustments are not a regulatory requirement, but that they may have been a one-time exception for PSNH.

B. Other States are Undergoing Comprehensive Proceedings to Integrate MYRPs with PBR Mechanisms into Their Regulatory Structure

Q. Are MYRPs common in other states?

A. MYRPs are currently utilized in a few states, while many other states have opened formal proceedings to investigate them.[21] Many of the processes in other states are multi-year efforts with the objective of comprehensively designing a MYRP framework with complementary PBR mechanisms. State regulators are investing significant resources to ensure that MYRPs are designed properly.

[20] *See* Order No. 25,123 (June 28, 2010) in DE 09-035 at 32.
[21] E.g., Maryland, Hawai'i, and Minnesota all have proceeding open to examine aspects of a MYRP.

Q. What states have undergone regulatory framework reviews related to MYRP and other PBR components?

A. There are multiple states that are investigating MYRPs and PBR. Minnesota, Hawaii, New York, and Rhode Island are some examples. Each of these states have advanced state policy goals that have motivated stakeholders to consider significant changes to their regulatory structure.

At least three of these states started the process by committing to explicitly stated goals and then linked the goals to outcomes, and then created metrics to measure the utility's progress in achieving said goals. Each of the proceedings took multiple years and required extensive engagement from stakeholders.

Q. Why are states engaging in alternative regulation discussions?

A. Technology is altering the way the grid functions and impacting utility business models. Traditionally, the grid was a one-way flow of energy that needed to be balanced and maintained to ensure reliability. Today, customers' load can be controlled, smart inverters can provide grid services autonomously, generation can be placed essentially anywhere on the grid, and customers can now store energy for later consumption. These new technologies, along with new policy goals, are requiring thoughtful changes to the traditional regulatory framework in some areas. Many of these challenges are not easily addressed under traditional regulation due to the utilities' desire to sell energy and build capital infrastructure to grow their businesses.

For these reasons, stakeholders are beginning to seek answers through alternative regulation. While I support many forms of alternative regulation, regulators must take precautions to ensure that these policies are implemented in a way that benefits ratepayers.

Q. What are state regulators attempting to achieve with alternative regulation?

A. Regulators are seeking to align utility, shareholder, and ratepayer incentives in order to better achieve state policy goals. This is a difficult objective to achieve because of the trajectory of industry trends. On the one hand, utilities are facing financial challenges due to flat or decreasing sales. On the other hand, regulators are trying to identify regulatory tools that allow utilities to achieve policy goals efficiently. These industry dynamics are why regulators are turning to alternative regulation; alternative regulation, such as decoupling, MYRP, and PBR mechanisms, should directly link revenue recovery mechanisms (i.e., MYRP) with achieving state policy goals, such as advanced rate design, demand response, and integrating DERs.

Q. When deciding whether a MYRP is an appropriate regulatory change, what should the Commission consider?

A. The Commission should answer at least three questions. First, what policy goals is the state attempting to achieve more efficiently with an MYRP? Second, is an MYRP necessary to achieve the state policy goals (i.e. is it superior to other policy tools or approaches) more efficiently? Finally, if a MYRP is necessary, how should it be designed to achieve the intended state policy goals, while appropriately sharing risk between the utility and ratepayers? To answer the final question, the Commission would need to review, and potentially implement, numerous PBR mechanisms as discussed below.

Q. What should be the objective of regulators when implementing an MYRP?

A. MYRPs are meant to work in conjunction with PBR mechanisms to incentivize more efficient operations, management, and capital investments from utilities, while more efficiently achieving policy goals. However, MYRPs must be specifically designed to incent desirable performance and require continuous monitoring.

Q. Why is it important to monitor and ensure that utilities are performing satisfactorily during a MYRP?

A. Poorly implemented MYRPs have the potential to magnify and accelerate many of the shortcomings of traditional cost-of-service regulation. Some of the unintended consequences of poorly designed MYRPs include: (1) a reduction in cost control incentives due to decreased regulatory lag; (2) degraded service quality due to selective cost-cutting; (3) fewer opportunities for stakeholders to influence the achievement of state policy goals due to longer periods without tariff changes; (4) incentives for poor O&M productivity; and (5) suboptimal capital investments due to a lack of transparency. A comprehensive PBR Framework is designed to address many of these perverse incentives— PSNH's proposal has all these shortcomings.[22]

Q. Is it easy to design a comprehensive PBR framework conducive to implementing MYRPs?

A. No. According to the Hawaiian Electric Companies, MYRPs "are complex regulatory systems that require skills that the regulatory communities in some states do not possess. It can be difficult to design plans that incentivize better performance without undue risk and share benefits fairly between utilities and their customers."[23]

This adequately describes Minnesota's experience attempting to implement an MYRP. Minnesota has revisited the structure of its regulatory framework repeatedly over the last six years to address issues related to implementing MYRPs and continues to do so today. While comprehensive PBR frameworks have great potential to create benefits for utilities and ratepayers, getting the framework right is difficult and requires focused attention from regulators.

C. PBR Mechanisms and Framework

Q. What are some of the PBR mechanisms that regulators consider when creating a more comprehensive PBR framework?

[22] While PSNH currently reports reliability metrics, regulators have not set a target performance level to define "good" and "bad" performance. Therefore, there is no financial penalty associated with poor performance.
[23] Docket No. 2018-0088. HECO Brief #3, Exhibit 1 at 24.

A. While the utilization and structural design of components within a PBR framework vary widely by state and country, the MYRP is often complemented by numerous PBR mechanisms, such as efficiency carry-over mechanisms, consumer dividends, and various forms of performance tracking.[24] Many of the PBR mechanisms that complement an MYRP are designed to protect consumers by better aligning the economic incentives within the PBR framework with state policy goals.

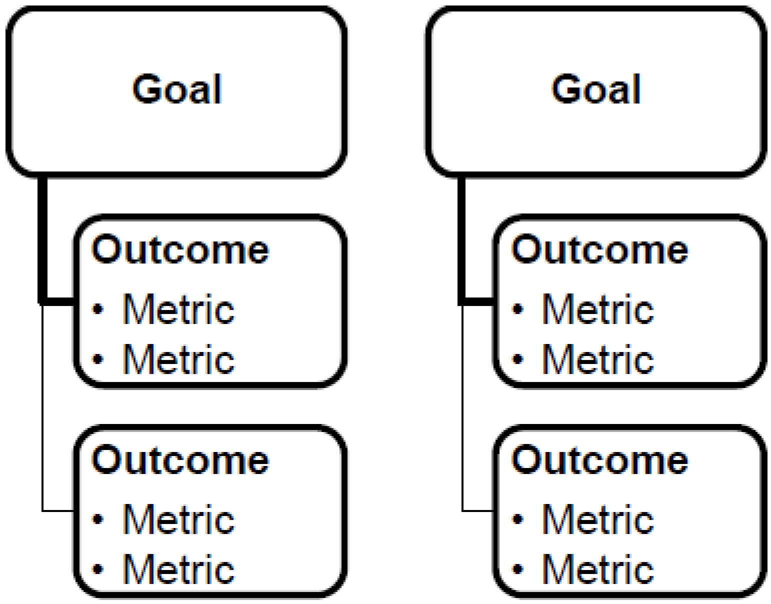
Q. Please provide an example of a PBR mechanism that is used to protect consumers.

A. Performance mechanisms are an example of an important consumer protection that can be utilized when moving to a PBR regime. When designing a PBR framework, multiple states have utilized a hierarchy approach of goals, outcomes, and metrics. This three-level hierarchy begins at broad regulatory goals, which inform desired regulatory outcomes, which in turn inform performance metrics.[25] The organization is visualized in Figure 1, below.

[24] An efficiency carryover mechanism allows the utility to benefit from operational efficiency gains throughout and, more importantly, across MYRPs. For example, if utilities are able to lower the cost of service during a MYRP by 10 percent, they would be allowed to capture a portion of that benefit as opposed to having to lower rates by a matching amount in the next MYRP period. A consumer dividend is a feature of revenue cap regimes that reduces the utility's revenue by a predetermined amount.

[25] See MN PUC Docket No. E-002/CI-17-401. Comments of the MN OAG at 18. Filed December 21, 2017.

Figure 1



The three-level hierarchy helps to transform regulatory goals, which are by nature aspirational and broad, into actionable performance metrics. This structure clarifies the relationships in the path from regulatory goal, to desired outcome, to metric—and back again.[26]

Once the three-level hierarchy has been established, performance areas can be prioritized by creating a hierarchy of metrics. Performance mechanisms can be divided into reported metrics, scorecard metrics, and PIMs. Reported metrics are for informational purposes and can be elevated to scorecard metrics or PIMs later. Scorecard metrics are often reported in a public-facing manner, such as on a utility's

[26] See MN PUC Docket No. E-002/CI-17-401. Comments of the MN OAG at 18. Filed December 21, 2017.

website. Lastly, PIMs are reserved for priority outcomes, or areas of especially poor performance, because they reward and/or penalize a utility's performance with a financial incentive. The purpose of each type of performance mechanism is to tie explicit policy goals to metrics in order to ensure utilities are accomplishing these goals and ratepayers are benefiting from the PBR framework.

Performance mechanisms are extremely useful in all forms of regulatory frameworks, given the flexibility with which they are implemented. New Hampshire employs numerous performance mechanisms currently, including reported metrics (e.g., SAIDI) and a PIM (i.e., the shareholder incentive mechanism applicable to the Energy Efficiency Resource Standard (EERS)). While many basic performance mechanisms, such as SAIDI and SAIFI, are monitored within traditional regulatory frameworks, additional performance mechanisms are often employed when a state moves toward a more performance-based regulatory approach.

PBR frameworks often rely heavily on performance mechanisms to focus the utility on key policy areas and reward them for excellent performance. The additional regulatory scrutiny ensures that ratepayers are receiving benefits under the PBR framework. In exchange for increased regulatory scrutiny, utility's often get improved revenue collection through an MYRP.

Q. Did PSNH propose additional PBR-related components to ensure ratepayers would receive benefits, given that it will immediately benefit through improved revenue recovery?

A. No. PSNH's MYRP lacks any significant connection to performance, which results in risk being shifted from the utility and shareholders to ratepayers.

D. PSNH's Proposed MYRP Fails to Align Utility and Ratepayer Incentives

Q. What justifications has the Commission previously relied upon when approving MYRPs?

A. The Commission has supported the notion that MYRPs reduce regulatory lag, reduce the number and associated cost of rate cases, and encourage the utility to invest in the grid.[27]

As discussed above, regulatory lag and costs associated with reduced rate cases are not sufficient justification for approving a MYRP and are not necessarily benefits derived from a MYRP.

As for encouraging a utility to invest in the grid, the nature of utility investments has changed. Not all grid investments provide "passive" benefits like a utility pole. Instead, regulators need to incent utilities to invest wisely, not just incent them to spend money.

In the remainder of this section, I discuss how some characteristics of New Hampshire's current regulatory framework are not conducive to effective implementation of MYRPs. Specifically, I discuss that the historical consumer

[27] *See* Order No. 26,007 (April 20, 2017) in DE 16-384. *See also* Order No. 25,123 (June 28, 2010) in DE 09-035.

protections that have been utilized with MYRPs are inadequate and ineffective. I also discuss why Integrated Distribution Planning ("IDP") is a necessary complement to a MYRP.

1. Earning Sharing Mechanisms are Not Sufficient for Protecting Ratepayers

Q. In PSNH's 2009 rate case, did the Commission approve any regulatory mechanisms that could be considered a consumer protection?

A. Yes. The Commission adopted an Earning Sharing Mechanism ("ESM"), along with the MYRP. An ESM is a regulatory tool that requires the utility to "share" any earnings over a specific threshold with ratepayers.[28]

Q. Why did the Commission approve an ESM?

A. The Commission did not explicitly state the objective of adopting an ESM. However, it appears that the ESM is being used as a tool to help the utility avoid over-earning (i.e., a consumer protection).

Q. Does an ESM provide sufficient consumer protections for ratepayers within a MYRP regime?

A. No. An ESM does provide some incentive for utilities to reduce their costs, by allowing the utility to realize some of the cost savings as earnings. It also provides benefits to customers by reducing their costs proportional to utility savings. However,

[28] In some instances, ESM have been proposed to share the down-side risk associated with earnings.

an ESM does not explicitly incent utilities to reduce investment or to avoid over investment. For example, an ESM structure would allow a utility to maximize earnings by reducing non-earning cost activities while increasing capital investments. Neither of these situations necessarily results in ratepayers being better off.

In fact, even within a comprehensive PBR framework, an ESM may fail to provide a clear benefit to ratepayers. Instead, other approaches, such as consumer dividends, may create a superior incentive structure for utilities operating under a revenue cap PBR framework.

A consumer dividend is an explicit decrease in annual revenues. No matter how the utility performs, the consumer dividend is annually subtracted from the utility's allowed revenues. Of course, the consumer dividend can only be implemented within a regulatory regime that incorporates a revenue cap. However, when applicable consumer dividends are superior to ESMs. ESMs may cause more harm than good on utility incentives when utilized within an unstructured MYRP framework.

2. *Advances in Integrated Distribution Planning are Required Before an MYRP is Approved*

Q. What is your understanding of the current distribution planning process utilized by utilities in New Hampshire?

A. New Hampshire utilities are currently required to file Least Cost Integrated Resource Plans ("LCIRPs"). However, the IDP proceeding (i.e., IR 15-296, the grid modernization investigation in which the PUC Staff has embraced a transition to integrated distribution planning) is ongoing and may lead to alternative planning requirements for utilities. The OCA recently filed comments that include its proposal for a more modern IDP process.[29]

Q. What shortcomings are present within PSNH's current investment process that make it incompatible with effective implementation of an MYRP?

A. The current investment process utilized by PSNH lacks transparency, objective investment comparisons, and accountability. These issues are evidenced by the support provided for the Company's base capital plan and Grid Transformation and Enablement Program ("GTEP") proposals and previous investments decisions.

a) Base Capital Plan and GTEP

Q. Please explain the Company's base capital plan and GTEP.

A. The Company's base capital plan is a forecast of the potential capital investments that will be made over the next five years.[30] The forecasted spending is not tied directly to specific projects, beyond one year, and is divided into four spending categories. The spending categories within the base capital plan are (1) reliability, (2) basic business, (3) new customer, and (4) capacity.[31] The majority of the capital base plan spending

[29] *See* Testimony of Paul J. Alvarez and Dennis Stephens. (September 6, 2019) in IR 15-296.
[30] *See* Witnesses Purington and Lajoie Testimony, Bates 420.
[31] *See* Witnesses Purington and Lajoie Testimony, Bates 422.

(approximately 66 percent) is related to maintaining and enhancing reliability. The capital base plans inform the MYRP's revenue requirement.

The GTEP is a multi-year proposal to increase the spending associated with the base capital plan to increase resiliency.[32] The spending associated with GTEP would be collected through the proposed Distribution Rate Adjustment Mechanism ("DRAM"), a rate rider.

I address the base capital plan and GTEP together because the spending types are similar and are related to the interconnections between IDP and a comprehensive MYRP regulatory structure.

Q. What problems do you have with the information and process provided by the Company to support base capital and GTEP spending?

A. The Company is proposing to spend hundreds of millions of dollars over the term of its MYRP, but it failed to provide crucial information and safeguards for ratepayers. First, the Company did not specify how the investments will deliver any measurable performance improvements. Second, the Company failed to demonstrate that its capital base plan and GTEP investments are reasonably cost-effective options. Third, the Company claimed that this spending is needed to "build a platform for the future," but provided no information about the future state they are trying to achieve,

[32] *See* Witnesses Chung and Dixon Testimony, Bates 178.

the needed capabilities or resources to achieve it, nor how the proposed investments advance those objectives.

Q. Why is it important to identify incremental performance improvements?

A. Measuring performance improvements within a MYRP framework increases the accountability related to spending tied to specific objectives. For example, the Company repeatedly noted that the capital base plan and GTEP spending would improve resiliency and reliability.[33] The Company's failure to link commitment to performance improvements or to a range of performance results in a lack of accountability, and creates no regulatory transparency about the efficacy or efficiency of the proposed spending plan.

First, the Company does not measure or define resiliency. Without any specific metrics to either measure current performance or proposed improvements, it is difficult to identify (1) why resiliency improvements are needed, (2) the level of improvement that is needed, (3) the Company's target improvement level and (4) the investments that are needed to achieve this target. Further, lack of clear performance metrics removes transparency and accountability for effective investment of ratepayer funds.

Second, while the Company measures and reports reliability metrics, it sets only internal targets for these metrics.[34] Regulators and customer advocates should have transparency around reliability performance levels. This allows regulators and

[33] *See generally,* Witnesses Purington and Lajoie and Witnesses Chung and Dixon.
[34] *See* Confidential Data Response OCA 07-019C.

customer advocates to support the Company in establishing performance levels that best align customer reliability preferences with affordability.

Lastly, the Company must provide transparency on how it calculates and evaluates performance related to reliability. Without transparency (e.g., data, methodology, etc.), around reliability metrics, it is difficult if not impossible for regulators and customer advocates to appropriately understand the potential benefits that customers receive from reliability improvements.

Q. How could the Company's proposal be improved with performance mechanisms?

A. Stakeholders should help to set targets for reliability performance. Setting a target would relieve the utility of any pressure to improve reliability continually. Instead, the utility would need to establish and maintain an explicit level of reliability that appropriately balances customer service levels with customer affordability. This may help control over-spending on reliability investments that provide diminishing margin returns.

Q. Why should the Company need to demonstrate that the capital base and GTEP plans are cost-effective?

A. Different investment portfolios can achieve the same reliability level, but not all of these investment portfolios will be equally cost effective. The suite of benefits and costs associated with the different options can be evaluated through cost-benefit modeling. While cost-benefit analysis should not be used to evaluate every investment, it should be integrated into the planning process to some degree to ensure that utility investments are providing the greatest benefit to customers and to improve transparency.

Cost-benefit analysis is becoming increasingly important because technology is changing rapidly and creating increased optionality around the types of solutions that utilities can deploy. For example, the Company recently chose to deploy residential meters without advanced functionalities. This decision was made without stakeholder input, and did not include potential benefits from advanced metering functionality, including the ability to establish time of use ("TOU") rates. This led the company to invest millions of dollars into outdated technology. Without a more robust and transparent IDP, it is impossible for regulators and stakeholders to provide input into these types of decisions.[35]

Q. Explain the Company's claim that the spending plans are required to "build the platform of the future."

A. The Company made this claim during the second technical conference. This framing of the spending plans highlights some of gaps with the information and planning provided in this case. To build the future platform, there are, arguably, prerequisites before the Company makes significant investments.

[35] *See* Testimony of Paul J. Alvarez and Dennis Stephens (September 6, 2019) in IR 15-296.

First, the Company does not forecast distributed energy resources ("DERs"). Forecasting DERs is necessary to provide to utilities and regulators insights into the needed pace and location of distribution system investments. DER adoption is often clustered locationally, so system upgrades can be targeted rather than system-wide. Additionally, New Hampshire has relatively low DER penetrations that may not require immediate system upgrades.

Second, the Company has not upgraded its interconnection standards recently and has not considered current IEEE standards, including 1547-2018 and 2030.5. Updating interconnection and engineering standards are important because they could reduce distribution system investments. For example, the Company has noted that one of its objectives is to increase hosting capacity on the distribution system with its spending plans.[36] However, customer-owned smart inverters or energy storage systems could be used to increase hosting capacity. Through updated interconnection standards, smart inverters can be required to operate under specific configurations to increase hosting capacity. Energy storage can also be operated to increase hosting capacity. Embedding increased hosting capacity into the entire distribution system may be a costly investment. Before upgrading the entire systems hosting capacity, these lower cost alternatives should be explored.

Third, the Company refused to provide any detailed grid modernization plans in discovery. Grid modernization plans can include a variety of different investments,

[36] *See* Schedule REN-2.

from advanced metering, to smart distribution devices, to back-end system overhauls. Without further detail, it is impossible to understand how the Company is planning to spend grid modernization funds, and what benefits that customers will receive from the investments. Before approving a utility's future platform, regulators should ensure that the utility's plans for the future align with ratepayer needs. PSNH failed to demonstrate that the hundreds of millions of dollars it claims to need to build the future grid aligns with ratepayer needs or state policy goals. This need is additionally suspect given that PSNH has historically chosen to invest in outdated technologies that fail to envision future customer needs or use cases, as evidenced by its investment in outdated meters.

Q. How is your discussion related to the capital base plan and GTEP related to the IDP and MYRPs?

A. The issues above demonstrate that the Company's investments should be vetted through a more transparent process before being approved. Additionally, these issues demonstrate that the regulatory structure needs to incorporate performance incentive mechanisms that increase Company accountability to realize the benefits that these investments purportedly deliver.

Q. Please explain your recommendations related to the Company's proposed step-year adjustment.

A. I recommend that step-year adjustments beyond 2019 be rejected. Creating an MYRP is a significant regulatory change that requires additional safeguards for ratepayers. As I have just explained, an MYRP is not necessarily an inappropriate step for this or any other utility, but implementing such a significant change as a piecemeal reform would not yield the requisite balance between the interests of shareholders and those of ratepayers.

In the next section, I discuss how to more effectively implement decoupling in a way that better emphasizes performance and achieving state policy goals.

IV. Decoupling

Q. What is decoupling?

A. Decoupling is a regulatory mechanism that can be utilized to stabilize utility revenues in the face of declining sales, economic fluctuations and increased energy efficiency and DER adoption, among other things. Decoupling works by separating sales from revenues—insulating the utility from changes in sales, and stabilizing revenues. Decoupling can achieve this and other public policy goals to varying degrees by using different approaches.

Q. Does PSNH propose decoupling?

A. PSNH does not propose decoupling per se.

Q. Is PSNH required to propose decoupling at this time?

A. No. The Settlement Agreement adopted under Order 25,932 in Docket DE 15-137 required that at "each utility's first rate case following the first three-year period of the EERS, the utility seek approval of a new decoupling mechanism as an alternative to the LRAM."[37] The initial three-year EERS period expires on December 31, 2020.

Q. Why are you raising decoupling in your testimony?

A. For two reasons. First, as reflected in the language "*new* decoupling mechanism as an alternative to the LRAM," the LRAM is a one-sided form of decoupling that protects the utility but is devoid of consumer protection. Second, the Commission specifically stated that:

> "approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism and that [utilities] are required to seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before."[38]

Q. Please describe how LRAM is a form of decoupling.

A. The LRAM provides a financial incentive to encourage the utility to administer Energy Efficiency Resource Standard ("EERS") programs. LRAM is a form of limited decoupling where only specific causes of sales changes related to energy efficiency

[37] DE 15-137, Order 25,932 at page 30.
[38] DE 15-137, Order 25,932 at page 60.

implementation are included in the calculations for lost revenue recovery. This makes the LRAM an inefficient and inequitable form of decoupling.

A. The LRAM is an Inefficient and Inequitable form of Decoupling

Q. What has the Company proposed regarding its LRAM?

A. The Company has proposed to continue utilizing its LRAM.

Q. Do you have concerns with continuing the LRAM?

A. Yes. I have two high-level concerns. First, the LRAM is an inequitable and inefficient form of decoupling. Second, the Commission has made it clear that that the LRAM is a temporary mechanism that should be replaced by revenue decoupling or a similar mechanism. Seeking to maintain the LRAM in a rate case the year before it would have otherwise been required to propose another decoupling alternative is likely to perpetuate the anti-ratepayer bias implicit in an LRAM longer than the Commission intended. Given the length of time since the last PSNH rate case, this is a risk that should be mitigated. This can be solved by requiring the utility to address the issue in this rate case (as Liberty Utilities is addressing in its current electric rate case).

Q. Why is the LRAM an inequitable and inefficient form of decoupling?

A. The LRAM approach to decoupling has numerous shortcomings.

First, the LRAM asymmetrically benefits the utility, resulting in an inequitable outcome for ratepayers. The LRAM compensates the utility for theoretical lost revenues based on calculated energy savings from energy efficiency measures installed pursuant to the EERS. The theoretical nature of lost revenues is concerning because they are based on a mathematical formula and numerous assumptions that do not likely hold-up, which would lead to over-compensating the utility for lost revenues that were not in reality lost. Furthermore, when the utility has higher than predicted sales, resulting in revenue that exceeds what the Commission intended in setting the rates, ratepayers do not receive any refunded revenues. This creates asymmetry that can be avoided with other forms of decoupling.

Second, the LRAMs incentive is tied directly to specific energy efficiency programs offered by the utility. Directly tying the financial incentive to specific programs, results in narrowly targeted behavioral change. Specifically, the LRAM only impacts the economic incentive associated with EERS programs, no other forms of energy efficiency or conservation. This is important because energy efficiency and conservation take many forms, such as state and federal standards and DERs.

Q. What has the Commission ruled in recent dockets?

A. The Commission has addressed decoupling in at least two proceedings; the EERS proceeding (DE 15-137) and the most recent EnergyNorth rate case (DG 17-048).

Q. Please explain the relevant information from the EERS proceeding.

A. In the EERS proceeding, the Commission adopted a settlement agreement that required the utilities to move to an alternative form of decoupling, such as symmetrical revenue decoupling, discussed in the next section.[39] The EERS Settlement also increased the energy savings goals for both electric and natural gas utilities.

In the EnergyNorth rate case, the Commission stated that "[t]he LRAM was intended to be a temporary measure to remove the disincentive for utilities to undertake energy efficiency programs."[40] In that case, the Commission approved a revenue decoupling mechanism to replace the LRAM.

Q. What is your recommendation related to decoupling?

A. I recommend that the Commission reject the Company's proposal to continue its LRAM and replace it with a symmetrical revenue decoupling mechanism.

I provide support for this recommendation in the remainder of this section.

B. Symmetrical Revenue Decoupling

Q. How is symmetrical revenue decoupling different from the LRAM form of decoupling?

A. A symmetrical form of revenue decoupling is based on a total revenue requirement that is decoupled from sales. It requires utilities to return to ratepayers revenues that exceed those approved by the Commission. Symmetric revenue

[39] Energy Efficiency Resource Standard Settlement Agreement. Filed April 27, 2016 in Docket DE 15-137 at 6.
[40] *See* Order No. 26,122 (April 27, 2019) in DG 17-048 at 45.

decoupling achieves this by truing-up the utility's revenue requirement after an agreed-upon period of time (often annually) using a reconciliation mechanism to collect or refund revenues that diverge from the approved revenue requirement.

1. Symmetrical Revenue Decoupling Enables More Efficient Achievement of State Policy Goals

Q. What are some important differences between an LRAM and symmetrical revenue decoupling?

A. An LRAM compensates the utility for administering energy efficiency through incentives directly related to specific program energy savings based on assumptions about such savings and their negative effect on revenue.[41] In theory, the LRAM removes the disincentive that the utility has to implement said energy efficiency program. However, symmetrical revenue decoupling is more comprehensive approach to changing the utility's incentives. By compensating the utility through means other than kWh sales (e.g., a revenue per customer approach), symmetrical decoupling removes disincentives beyond those affected by the LRAM. For example, symmetrical decoupling removes the disincentive for utilities to impede DER adoption, advanced rate design, organic energy efficiency and, to a lesser extent, efficient integration of DERs.

[41] LRAMs incentives often consist of complicated savings calculations that can result in stakeholder disputes, resulting in the necessity of additional resources to implement.

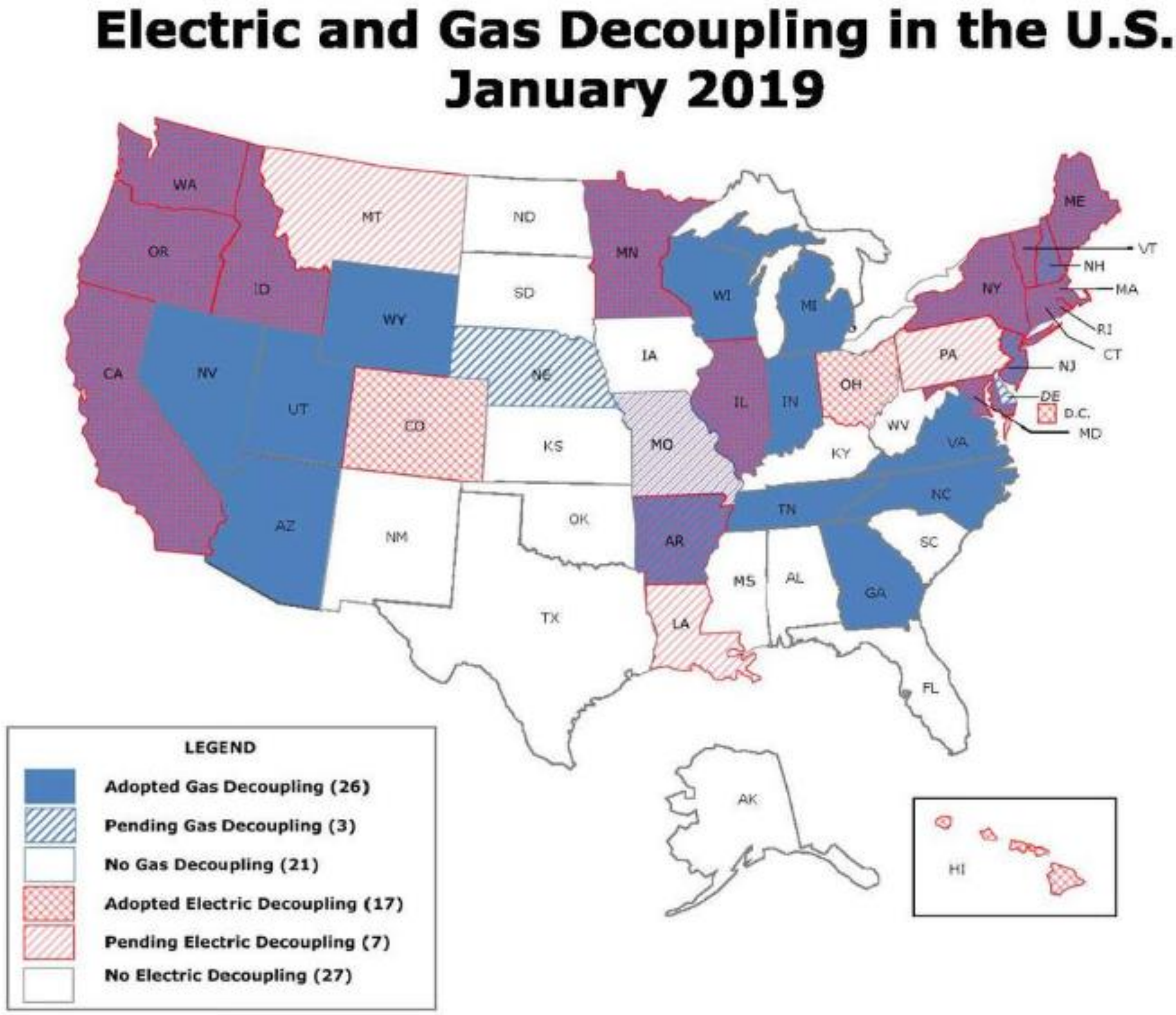
Additionally, not only does symmetrical revenue decoupling insulate the utility from revenue erosion associated with energy efficiency, but it protects ratepayers by limiting rate increases over a given period. The symmetry of this form of decoupling makes the mechanism more equitable for ratepayers.

Q. Which of the mechanisms is better suited to address modern regulatory challenges?

A. Without question, symmetrical revenue decoupling addresses modern regulatory challenges, such as DER adoption, more comprehensively than an LRAM. Symmetrical revenue decoupling more broadly alters utility incentives by more effectively divorcing energy sales from revenues.

Additionally, symmetric revenue decoupling has been adopted in numerous states throughout the country. The high level of adoptions provides regulators with additional certainty that any unintended consequences are minor and mitigable. Figure 2 displays the states that have adopted a form of decoupling similar to symmetric revenue decoupling.

Figure 2[42]



	2013		2018	
	Utilities	States	Utilities	States
Gas	49	20	64	26
Electric	24	14	42	17
Total	73	25	106	32

Figure 2 indicates that there has been a significant increase in the number of states with decoupling since 2013. Specifically, 42 electric utilities were decoupled in 2018.

[42] *See* https://www.nrdc.org/resources/gas-and-electric-decoupling. Note that Figure 2 does not depict the type of decoupling that each state has implemented. However, Figure 2 does not consider LRAMs decoupling mechanisms.

Currently, only 11 states utilize LRAMs, including New Hampshire.[43] Most of these states in are in the Southeast or Midwest.

2. As With Any Regulatory Mechanism, Symmetric Revenue Decoupling Requires Careful Implementation

Q. How does symmetrical revenue decoupling impact the economic incentives of a utility?

A. Theoretically, in the short-term, symmetrical revenue decoupling removes the utility's disincentive to encourage and to administer energy efficiency, DERs or other technologies that reduce the utility's kWh sales. Thus, symmetrical revenue decoupling generally has a positive effect on a utility's support for efficiency programs and creates additional revenue certainty for utilities in a declining sales environment. This revenue certainty can also facilitate lower borrowing costs and therefore lower costs to ratepayers.[44] However, in the medium- to long-term, the utility's incentives regarding energy efficiency, DERs, and other technologies are less clear.

This uncertainty exists because symmetrical revenue decoupling may not completely remove the utility's capital bias. Generally speaking, most utilities operating under a cost-of-service model have financial incentives to increase infrastructure

[43] *See* http://www.ncsl.org/Portals/1/Documents/energy/Utility_Incentives_4_2019_33375.pdf?ver=2019-04-04-154310-703

[44] *See* "Decoupling Design: Customizing Revenue Regulation to Your State's Priorities." The Regulatory Assistance Project. November 2016.

investments to grow rate base and thereby to increase revenues.[45] Increasing demand requirements (i.e., sales) is one way to justify more infrastructure spending. This suggests that decoupling's ability to "disincentivize" utilities from impeding progress related to energy efficiency, DERs, and other technologies may depend on how it is implemented. Flat or declining demand will reduce utility infrastructure needs, effectively reducing revenue opportunities under a cost-of-service model. These competitive threats incentivize utilities to continue to impede these alternative resources. Effective implementation of symmetrical revenue decoupling is critical to avoiding this conundrum.

Q. Why is the impact on utility incentives important?

A. An effective implementation process is critical to aligning incentives appropriately. These issues can be divided into those related to policy and technical design.

The policy issue that needs to be addressed through implementation is that symmetrical revenue decoupling does not, by itself, guarantee that any policy goals will be achieved nor that the utility performance will improve in any key areas. There needs to be a connection between performance and the utilities ability to be guaranteed a benefit from symmetrical revenue decoupling on day one due to a decreased risk

[45] *See* "Revenue Regulation and Decoupling: A Guide to Theory and Application". The Regulatory Assistance Project. June 2011.

profile. To correct this, I recommend that the Commission and Company adopt policy-related commitments at the same time that symmetrical revenue decoupling is adopted.

Implementation is also important when designing the technical specifications of the symmetrical revenue decoupling mechanism. The process is important to ensure that risk is appropriately shared between customer classes and between ratepayers and the utility.

3. Steps Towards a More Performance Focused Regulatory Framework

Q. When approving a symmetrical revenue decoupling mechanism in this case, what other actions should the Commission order?

A. The Commission should conceptualize decoupling in conjunction with a performance-focused regulatory framework. Additionally, via their respectively pending rate cases PSNH and Liberty have both expressed interest in MYRPs, which should prompt the Commission to focus more on performance and achieving policy goals. For these reasons, decoupling a utility should include additional commitments to achieving state policy goals. I recommend that the Commission:

1. Require that any decoupled utility commit to achieving more specific policy goals; and
2. Create a demand response performance incentive mechanism ("DR PIM").

a) Regulatory Commitments and Performance Metrics

Q. Please explain the more specific policy goals that utilities should adopt when decoupled.

A. Given that decoupling should change utility behavior related to energy efficiency, rate design and DERs, I propose several reasonable commitments that should accompany the adoption of any decoupling plan. First, utilities should specify a timeline for analyzing and, when cost-effective, implementing methods of distribution efficiency such as Conservation Voltage Reduction ("CVR"). Second, utilities should specify a timeline for updating DER interconnection standards. Finally, utilities should be required to provide additional specificity related to advanced rate designs.

Q. What is Conservation Voltage Reduction and why is requiring decoupled utilities to analyze and implement CVR reasonable?

A. CVR increases distribution efficiency and has been demonstrated to be cost-effective for numerous utilities in most, if not all, regions of the country.[46] Results have demonstrated that CVR can shave 5 percent off peak demand and achieve energy savings of over 3 percent.[47] There is clearly potential to create benefits for ratepayers through the implementation of CVR. Given the connection of CVR to energy efficiency

[46] *E.g., See* Department of Energy, Distribution Automation (2016). Available at: https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf
[47] *See* http://varentec.com/varentec-deploys-grid-edge-control-meet-aggressive-energy-savings-goals-denver-across-472-circuits-xcel-energy/. See also Kootenai Electric's presentation under Grid Ops Track: Session Two. Available at: https://smartgridnw.org/gridfwd-2018-presentations/.

and demand savings, revenue decoupling should remove the disincentive for utilities to implement CVR rapidly.

CVR may be a productive step towards a more performance-focused regulatory framework. The benefits created through CVR can vary by utility. The variation is related to multiple factors. Some factors are controlled by the utility, while others are not. For example, when implementing CVR, the distribution system's current design characteristics and configuration are given. The distribution system's current design and configuration will impact the potential benefits that can be generated with CVR. On the other hand, how CVR is operated can also impact the benefits created—the utility has control over operations. For this reason, it may help to create a performance mechanism that aids in the maximization of CVR benefits.

Q. Why is requiring decoupled utilities to commit to updating interconnection standards reasonable?

A. Given that symmetrical revenue decoupling partially removes utilities' disincentive for adopting and integrating DERs, utilities should commit to updating interconnection standards.

Currently, New Hampshire's Puc 900 Rules could use updating for multiple reasons. For example, the Puc 900 Rules do not mention energy storage systems, rely on IEEE 1547-2003 when 1547-2018 is the current standard, and do not explicitly integrate components of IEEE 2030.5. Updating the interconnection standards will lower barriers for adopting DERs and may result in more cost-effective integration.

More specifically, updating interconnection standards could lead to decreased distribution system infrastructure spending.[48] There are two ways that reductions in distribution system infrastructure could be realized: at the system level, and during the interconnection process. Regarding the system level, some utilities are currently upgrading their systems to increase hosting capacity in preparation for high penetrations of DERs. However, technologies installed with the DERs, such as smart inverter functionality, could be utilized to increase hosting capacity. Regarding the interconnection process, allowing interconnecting facilities to pair with energy storage systems and, more generally, incorporating the operational characteristics of energy storage systems can mitigate the need for interconnection upgrades. Take a residential solar plus storage system, for example, with 8 kW of solar and 8 kW of storage (together, "facility"). Utilities can evaluate this facility as though it will export 16 kW when the grid is the least equipped to handle its export—which may trigger the need for a grid upgrade. However, interconnection standards could be updated to reflect the operational characteristics of this facility more accurately. In fact, one simple solution would be limiting facility exports through its smart inverter (i.e., by configuring the smart inverter to limit exports to no more than 8 kW).

[48] For example, New York is piloting a "flexible interconnection capacity solution" to avoid system upgrades. *See* *https://www.nrel.gov/dgic/interconnection-insights-2018-08-31.html*

It would be reasonable for a decoupled utility to commit to interconnection standards updates. While updating interconnection standards may not be a near term priority, it may be reasonable to require that an interconnection standards proceeding be established before the Commission approves an MYRP. Another reasonable option would be for the utilities to commit to opening a proceeding once a certain DER penetration threshold has been exceeded.

Q. What advanced rate design information should a decoupled utility commit to providing?

A. A decoupled utility should create and file with the Commission a formal advanced rate design roadmap that specifies how and when the Company will refine its rates for each customer class. The advanced rate design roadmaps should address two general areas.

First, the utility should explain how it plans to leverage the functionality of its existing investments to design rates that maximize benefits for ratepayers. For example, if the Company has the functionality (e.g., interval metering) to implement advanced rate designs, it should explain when those functionalities will be implemented or explain why those functionalities should not be used. Having documentation of the current status of advanced rate design before a utility is decoupled provides the Commission with important information that can be used to determine whether decoupling leads to any behavioral change with respect to advanced rate design.

The second area that should be addressed in a utility's advanced rate design roadmap is the future plan for advanced rate design. This should include a description of the utility's desired advanced rate design structures by customer class, the scale at which advanced rate designs will be implemented by customer class, investments required to obtain the needed functionality to implement advanced rate designs and the timeline on which investments are planned, among other information. For example, a utility's desired advanced rate design for larger customer classes could be TOU with Critical Peak Pricing ("CPP"). The general design characteristics should be specified, such as number of time periods, number of hours within each period and pricing ratios between each period. Additionally, the utility would specify the investment needed to enable to the rate design, the associated timeline and the scale of the rollout (e.g., opt-out versus optional rate designs). Obtaining specificity related to the future state of advanced rate design will be useful to stakeholders and the Commission in numerous dockets.

Q. How would the advanced rate design roadmap be used?

A. The advanced rate design roadmap could be used to inform cost-benefit analysis in the IDP proceeding, a qualitative measure of performance, and as an indicator of decoupling's impact on utility incentives.

Q. Is PSNH currently under-utilizing metering capability for any of its customer classes?

A. Yes. Numerous commercial and industrial rate classes have interval metering. However, the current energy charges for these classes are unrefined and many rely too heavily on demand charges to collect system costs. PSNH should be required to improve the rate design for these classes, by making them more cost reflective to better encourage energy efficiency and load management.

Q. Given that the OCA has championed decoupling in the previous proceedings, could your recommendations be interpreted as "moving the bar?"

A. My recommendations are consistent with previous positions taken by the OCA. Regarding the CVR, the OCA has provided comments in grid modernization proceeding that suggest this would be a cost-effective investment for regulated utilities in New Hampshire.[49] While interconnection has not been directly breached by the OCA in previous comments because it is an emergent policy issue, the OCA has previously supported the cost-effective integration of DERs.[50] Finally, regarding advanced rate design, the OCA recently requested that Unitil be required to file data that could be required within an advanced rate design roadmap.[51]

Each of these examples include positions taken outside of a rate case. The purpose of restating them within a rate case is to acknowledge the connection between improved revenue collection and state policy goals that are being discussed in other proceedings. Without tangible progress on state policy goals to balance symmetrical

[49] *See* Direct Testimony of Paul J. Alvarez and Dennis Stephens in IR 15-296. (September 6, 2019).
[50] *See* Testimony of Lon Huber filed in DE 16-576 (Oct. 24, 2016).
[51] *See* DE 16-576, OCA Comments at 2 (August 10, 2019).

revenue decoupling, risk is inequitably shifted from the utility and its shareholders to ratepayers.

Q. Has the OCA commented on performance metrics in any other docket that you are aware?

A. Yes. The OCA has outlined performance metrics that should be monitored in the grid modernization proceeding, IR 15-296. While I recommend adopting the recommendations above, I note that additional performance metrics could be reasonably adopted in the grid modernization docket. However, asymmetrical mechanisms such as the LRAM or unstructured MYRPs should either not be approved or should be approved contingent and subsequent to successful negotiation of the performance metrics that reflect New Hampshire policy goals.

b) Demand Response Performance Incentive Mechanism

Q. What is a Performance Incentive Mechanism and how does it relate to performance metrics?

A. A PIM is a metric paired with a performance benchmark/target and a financial incentive. PIMs provide financial motivation for utilities to improve performance toward desired policy outcomes, or to discourage underperformance. An example of an existing PIM in New Hampshire is the EERS shareholder incentive.

Q. Have you recently identified any common themes regarding the specific use of PIMs?

A. Yes. Many states have undertaken a significant stakeholder process to formulate performance metrics and PIMs. A number of these processes have resulted in the adoption of DR PIMs. In fact, Minnesota and Rhode Island both underwent significant stakeholder processes that considered numerous PIMs, but the Commissions in these states ultimately adopted only a DR PIM.[52]

Q. Why are states so focused on demand response?

A. Stakeholders and commissions see significant potential with new demand response programs. The potential with many of the new DR programs is their ability to dispatch to reduce a small number of key system demand peaks. These system peaks contribute significantly to system resource needs. Addressing the peaks through construction rather than demand response results in construction of resources with relatively low utilization rates and low overall customer value due to the infrequency of the system peaks. However, utilities have been slow to adopt many forms of demand response. For that reason, stakeholders and commissions may see this as an area where utilities are not performing well.

Additionally, after getting some experience with developing PBR-type regulatory frameworks, regulators appear to be adopting more simplified and focused

[52] *See* MN Docket No. 17-401 and Rhode Island Docket 4770.

approaches. There are likely at least two reasons for this. First, as discussed above, PBR can overwhelm regulators and the utility with numerous requirements—which does not increase efficiency for any stakeholder. Second, creating numerous PIMs not only diffuses focus, but it may result in compensating the utility twice for the service it provides. For example, having a demand response PIM and a PIM that measures the percentage of managed electric vehicle ("EV") load is likely duplicative.[53]

Q. Are you aware of any actions taken in New Hampshire to incentivize demand response?

A. Yes. It is my understanding that some demand response programs are currently administered under the EERS. It is also my understanding that both passive and active DR programs receive a return on expenses incentive and that funds are recovered from electric customers through the System Benefits Charge ("SBC").

The OCA has previously noted the shortcomings of using the EERS to administer mature direct load control and active DR programs. Specifically, the OCA noted that scaling DR programs may not be efficient under the EERS mechanism. To address this shortcoming, the OCA has recommended that another funding mechanism be used to administer direct load control and active DR programs.[54]

[53] Xcel Energy recently proposed a similar EV PIM and has already been ordered by the Minnesota Commission to create a demand response PIM. See MN Docket Nos. 19-564 and 17-401.
[54] *See* Docket No. DE 16-576, OCA Comments at 7. Filed March 8, 2019.

Q. Do you have a recommendation for more effectively administering DR programs' PIM?

A. Yes. I recommend that the Commission create a discrete DR PIM. In doing so, I recommend that the Commission should: (1) use a shared savings incentive that utilizes the Granite State Test;[55] (2) administer future demand response programs through a new DR PIM, not through the EERS; (3) fund the incentive and programs through a separate mechanism, such as the Distribution Rate Adjustment Mechanism ("DRAM"), not the System Benefits Charge that funds the EERS programs; and (4) open a new proceeding to design the specifics of the PIM.

Q. One of the EERS working groups recently finished a report on performance incentives, so why should the Commission order stakeholders to create a DR PIM now?

A. There are multiple reasons that the Commission should act now to create a discrete DR PIM. First, using the EERS incentive could result in an inequitable reward for the utility. Second, a PIM based on shared savings would better align utility, shareholder and ratepayer incentives. Finally, the current funding mechanism, used for

[55] *See* Erin Malone, Tim Woolf, and Steve Letendre, "New Hampshire Cost Effectiveness Review" (Oct. 14, 2019) filed in DE 17-136 at 50-52 (describing Granite State Test as developed by Benefit-Cost Working Group in conjunction with Synapse Energy Economics).

the EERS, may not result in efficient deployment of both DR and energy efficiency resources.

Q. Why could the EERS mechanism result in an inequitable reward for the utility?

A. The financial incentive under the current EERS does not accurately reflect the utility's performance because it is based on spending amounts. The objective of any PIM is to align utility, shareholder, and ratepayer incentives more fully and effectively. Administering and incentivizing DR programs through the current EERS mechanism does not accomplish this objective. The rate of return structure of the EERS mechanism rewards the utility for any and all investment whether it leads to positive outcomes or not. The rate of return incentive structure is inappropriate for measuring the performance of modern utility DR programs because their value varies greatly with their utilization (i.e., ability to dispatch at peak times). Instead, a DR PIM should be designed to reward the utility when it beneficially utilizes (i.e., dispatches during critical peaks) the DR resource effectively.

With an active demand response resource, for example, the utility should be rewarded when the DR resources are successfully dispatched to reduce a monthly or annually Independent System Operate ("ISO") New England peak. The monthly and annual peaks in ISO New England are used to allocate large portions of demand related costs to utility customers in New Hampshire. For this reason, DR provides the most benefits to ratepayers when these peaks are decreased. On the other hand, if DR resources are invested but do not decrease the ISO New England peaks, little to no benefit is created for ratepayers—a fact that should be explicitly reflected in the design of the DR PIM.

Q. Why should the DR PIM be based on shared savings?

A. A shared savings PIM would better align shareholder, utility and ratepayer incentives by providing rewards more reflective of the benefits created. When utilities can accurately forecast peaks and dispatch DR resources to reduce them, the utilities should be rewarded through a portion of the savings generated. Utilities should also be encouraged to participate with third parties to reduce peaks. Therefore, a shared savings incentive would be a more equitable structure for DR programs.

Q. Why should the Commission alter the funding mechanism for a new DR PIM?

A. There are many reasons that the Commission should create a new funding mechanism for a discrete DR PIM. I discuss two reasons.

First, a separate funding mechanism for a DR PIM would allow DR programs to scale without effecting funding levels for energy efficiency programs. The EERS provides foundational funding for energy efficiency. It was not originally envisioned to also provide funding for DR programs. DR and energy efficiency are important system resources due to the flexibility and certainty they provide the power system. It is necessary to create separate funding mechanisms to enable efficient levels of both resources to be deployed.

Lastly, a separate funding mechanism would likely allow for more cost-effective DR and energy efficiency programs to be funded. Under the current SBC, it is not clear that sufficient funding is required for DR programs.[56] Impeding the deployment of cost-effective DR and energy efficiency programs would go against the principles of least-cost planning and may not lead to just and reasonable rates.

Q. Has the Company proposed a rate mechanism that could be used to collect the costs associated with a new DR PIM?

A. Yes. The DRAM could be utilized or a similar rate mechanism.

4. Symmetrical Revenue Decoupling Mechanism: Technical Design Characteristics

Q. Why is the technical design of a symmetrical revenue decoupling mechanism important?

A. A symmetrical revenue decoupling mechanism is used to calculate the annual surplus or shortfall between the actual and approved revenues. The details of how the calculation is made are important to ensure that risk is shared between the utility and ratepayers equitably and to ensure that each customer class pays an equitable share.

[56] *See* OCA Comments at 7, filed March 8, 2019 in DE 16-576.

Q. What technical design characteristics should PSNH's symmetrical revenue decoupling mechanism have?

A. I recommend a symmetrical revenue decoupling mechanism similar to the one proposed by Liberty Utilities in Docket 19-064 with the modifications that I recommended in that case.

Specifically, I recommend the following characteristics: (1) full revenue decoupling mechanism; (2) revenue per customer structure applied to each customer class; (3) all customer classes participate;[57] (4) true-ups completed annually based on a total revenue allocator; (5) annual adjustment limited to a soft cap of plus or minus 3 percent; (6) for rate classes that utilize time-varying rates, the decoupling surcharge applied to the peak period and any refund applied to the off-peak period; and (7) PSNH required to file the same information annually as that ordered by the Commission in the EnergyNorth (Liberty Utilities) rate case.[58]

Q. Please discuss the objective of your technical design recommendation.

---

[57] Each customer class should participate, unless there is a high percentage of customers within a class with contracted rates.

[58] *See* Order No. 26,122 (April 27, 2019) in DG 17-048 at 46 ("Further, to assist the Commission in evaluating Liberty's decoupling, we require the Company to report in its next rate case on the following: (1) the amount of revenue collected or passed back through this mechanism, by year; (2) an account of any measurable impacts decoupling had on Liberty's utility sponsored energy efficiency programs; (3) a detailed list of all efforts the Company made to promote its own energy efficiency programs, and to promote other energy efficiency measures such as lobbying for stricter building/energy codes; (4) an account of efforts taken to educate builders about energy efficiency; (5) a detailed list of meetings with state and local officials and associations to promote energy efficiency; (6) customer feedback resulting from decoupling as implemented through the rate design; and (7) any changes in the Company's credit rating.").

A. Creating a symmetrical revenue decoupling mechanism with these design characteristics, will aid in the equitable sharing of risk between ratepayers and the utility and within customer classes.

Q. Please provide examples of how risk would be shared equitably using your design criteria.

A. There are numerous design characteristics that are intended to share risk equitably between ratepayers. First, using a full, as opposed to partial, decoupling mechanism insulates the utility from sales risk associated with weather. Second, the use of revenue per customer, as opposed to a total revenues approach, acknowledges that the Company will incur some level of cost increases as the customer base grows. Finally, the symmetrical soft cap will allow the utility to collect all under-collections over time. Some states have implemented hard caps or asymmetric caps that shift risk to the utility.

I have also recommended numerous design characteristics that will ensure equity between customer classes. First, requiring that all customers participate, ensures that all customers equally bear the costs and benefits of removing the utility’s disincentive to administer energy efficiency programs effectively. This is fair because all customer classes benefit from energy efficiency programs. Second, allocating any under- or over-collection using a total revenues allocator ensures symmetry between collecting revenues through rates and refunding or surcharging through a revenue decoupling mechanism.[59]

V. ALLOCATED COST OF SERVICE STUDY

A. The Influence of Economic Incentives on Cost of Service Studies

Q. Before you discuss the details of an ACOSS, please explain how economic incentives may influence cost studies.

A. When evaluating cost studies, and the rate designs they inform, decision-makers should consider how the economic incentives of for-profit investor-owned utilities ("IOUs") can impact assumptions within utility-sponsored cost of service studies.

In a perfect world, corporate profit maximization would align with the objectives of those corporations' customers. However, that is not the case for IOUs. In fact, I have spent the entirety of my testimony up to this point discussing the shortcomings associated with utility business models. For this reason, it is important for decision-makers to understand how IOUs' economic incentives may not align with public policy goals and ratepayer interests in order to evaluate cost modeling and rate design proposals more effectively.

[59] The symmetry stems from the factor that revenues are proportionally to the number of customers, demand, and energy characteristics of each customer classes. A total revenues allocator is a composite allocator based on all of these characteristics. Using another type of allocator, such as an energy allocator, skews the portion of refunds or surcharges away from how revenues are collected through rates by over-emphasizing one characteristic of revenue collection.

Q. Please provide examples of where a utility's economic incentives may not align with policy goals or ratepayer interests.

A. There are two interrelated issues that can impact the utilities' perspective when conducting cost studies.

First, the price elasticity of demand for electricity is the sensitivity, or elasticity, associated with the quantity of electricity demanded given a change in the price of electricity. Specifically, the elasticity of demand measures how much an electricity consumer changes her consumption of a good given a change in price. Because large customers have more elastic demand than residents, large customers will decrease their demand for electricity more than residents due to an equivalent price change, all else constant. This relationship means that utilities can benefit financially from shifting costs from large to residential customers. This presents the utility with an incentive to shift subjective cost allocations (and there are many in cost studies) to classes with inelastic demand by increasing their rates.[60]

Second, third-party services act as substitutes for utility services. Traditionally, utilities have had few competitors (e.g. other utilities or natural gas as a fuel alternative) and never have utilities faced competition on the distribution system. Currently, competitors are providing services that compete with those provided by the utility, such as solar plus storage. The presence of this competition impacts utility incentives in

[60] *See generally* James C. Bonbright, Albert L. Danielsen, & David Kamerschen, *Principles of Public Utility Rates* (2d ed. 1988).

many ways, but generally utilities may take actions to make their services more cost competitive in an unfair fashion.

Q. How do the economic incentives of a utility impact cost studies in practice?

A. The utility perspective is largely informed by its economic incentives. For this reason, when subjective determinations are made within a cost of service study or when designing rates, utilities are likely to make assumptions that benefit their bottom line — as would any for-profit business in a similar position. This is especially problematic in cost studies and rate design because there are numerous subjective assumptions made to develop both. I provide examples of subjective decisions made by PSNH below.

Q. Why are you highlighting these perverse economic incentives for decision-makers?

A. My goal is to ensure that decision-makers understand the economic incentives that influence the perspectives a utility shares in regulatory proceedings and when it constructs cost of service models. My goal is not, however, to demonize the utility, which is simply responding to the regulatory framework and the resulting economic incentives in which the Company operates. For this reason, creating a more effective regulatory framework is fundamental to better aligning the economic incentives of a utility with the needs of its customers.

B. Objectives and Background

Q. Did PSNH file an embedded ACOSS?

A. Yes. The Company filed an embedded ACOSS to inform its revenue apportionment. It also filed an MCOSS to inform its rate design recommendations. While these two studies have overlap in their purposes and objectives, this section specifically addresses the Company's ACOSS and will inform my revenue apportionment recommendations and provide useful information for design rates. I will address the MCOSS in Section VI.

Q. What is the purpose of an ACOSS?

A. The purpose of an ACOSS is to decipher, with as much detail and accuracy as possible, which customer class caused the utility's various embedded costs associated with providing service.

Q. How is an ACOSS performed?

A. An ACOSS has three steps. First, costs are functionalized into various categories. Second, costs are classified as energy, demand/capacity, or customer. Lastly, the costs are allocated to the various customer classes using allocators related to energy, demand/capacity, or customer characteristics.

Q. How are costs functionalized?

A. Public utilities are required to maintain records in accordance with the Uniform System of Accounts as designated by the Federal Energy Regulatory Commission ("FERC"). These accounts assign costs by various functions, such as transmission and distribution. The purpose of functionalizing costs is to aid in determining which customers are jointly or solely responsible for various costs.

Many utilities also subfunctionalize costs by voltage level. For example, distribution costs can be subfunctionalized into primary and secondary voltages. Subfunctionalizing by voltage level adds more detail to the ACOSS and improves the accuracy of assigning costs when performed appropriately.

Q. How are costs then classified?

A. Cost causation is used to determine whether each cost is classified as a commodity, demand, or customer cost. Energy costs are classified based on a customer class's energy usage, measured in kilowatt-hours ("kWh"). Capacity costs are classified based on a customer class's contribution to peak demand, measured in kilowatts ("kW") within the system. Finally, customer costs are those required to provide service to customers, regardless of whether the customers consume electricity or not. Specifically, the National Association of Regulatory Utility Consumers ("NARUC") Electric Manual defines customer cost as "costs that are directly related to the number of customers served."[61] In other words, the utility incurs customer costs based on the *number* of customers on its system, rather than on the amount of energy they consume or when they consume it.

[61] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual, January*, 20 (1992). (hereinafter "NARUC Electric Manual")

Q. How are costs allocated once they have been classified?

A. Costs are allocated to customer classes based on each class's contribution to each classified cost. For example, if the company spends the same amount of time and money on each customer location, regardless of class, then it is appropriate to allocate that cost based on the number of customer locations. This result stems from the fact that the number of customer locations, rather than a customer's electricity consumption, causes costs to be incurred.

Q. How should an ACOSS analysis be used in a rate case?

A. Parties and the Commission should exercise caution when using any one ACOSS model to inform revenue apportionment or rates, as it is an inherently imprecise tool. Every cost analyst makes numerous, subjective determinations that will dramatically impact the results of the study. One salient example of subjective decision-making is how an analyst chooses to classify the distribution system. The classification of the distribution system has been argued about for over half a century.[62] This decision also has a significant effect on the results of an ACOSS, as I demonstrate below. To minimize the impact of this subjective decision, I include a different classification and allocation method for distribution system costs that are used by several utilities and commissions throughout the country. Considering these different ACOSS models will allow the Commission to view a range of results, which helps minimize the impact of an analyst's

[62] *See generally* James C. Bonbright, *Principles of Public Utility Rates* 348 (1st ed. 1961).

inherent bias on this contentious classification decision. I believe that considering the results associated with multiple ACOSSs that classify and allocate distribution system cost using commonly accepted methods provides useful context for the Commission in setting rates.[63]

With that said, some ACOSS models are better than others, even if both produce reasonable results. The Commission should not ignore this difference and should give more weight to ACOSS models that are better supported by economic theory, while recognizing that no ACOSS is perfect. Therefore, I have explained the reasons that the basic customer approach, which I present in Section V.C.1, is the most reasonable approach to classifying distribution system costs and should, therefore, be given the most weight by the Commission.

Q. Are there any current industry trends impacting traditional methods used within the ACOSS and MCOSS?

A. Yes. Technology is changing rapidly to meet evolving customer service demands, such as increased reliability, and to further state policy goals, such as integrating distributed and large-scale renewable energies. The new and expanding service requirements and policy goals require a cost analyst to re-evaluate cost causation issues that may previously have been considered settled. For example, modernizing the electric grid will impact the cost causation associated with grid investments in new

[63] *See* Jim Lazar, Regulatory Assistance Project, *Dividing the Pie: Cost Allocation, the First Step in the Rate Design Process*, *in* Smart Rate Design for a Smart Future Appendix A (2015).

ways. I discuss how these technological changes are impacting the traditional Cost of Service Studies ("COSSes") later in my testimony.

C. Classification and Allocation of Distribution System Costs

Q. What different approaches are used to classify distribution system costs?

A. There are multiple approaches to classifying distribution system costs. I provide detail on the basic customer and minimum system approaches in this section. However, there are also approaches that classify a portion of the distribution system as energy related.

1. Basic Customer Approach

Q. Can you describe the basic customer approach?

A. According to the basic customer approach, only costs that can be traced to a specific customer should be assigned as customer costs, because those are the only costs that vary based on the number of customers in a class. Under this theory, the costs of the distribution system cannot be attributed directly to a customer, because adding one customer to the system would not increase the costs of the distribution system. Instead, the basic customer approach recognizes that the distribution system is built to serve peak demand, and so its costs should be classified as demand.

Q. Please explain why classifying and allocating distribution system costs can differ between ACOSSs.

A. As stated by regulatory economist Charles Phillips, "[w]hen the same plant or equipment is used to provide several types of service, there is no one correct way to allocate these costs among the different units of service. Any method of apportionment is subject to dispute."[64] This statement is true for classifying and allocating distribution system costs as well. Therefore, various models incorporate different mechanisms to determine how the costs of the distribution system are classified and allocated.

Q. How would an ACOSS utilizing the basic customer approach differ from PSNH's proposed ACOSS in this case?

A. A basic customer ACOSS would differ in only one way from PSNH's minimum system ACOSS: It would classify distribution system costs differently. Specifically, the basic customer approach classifies FERC account 364-368 (referred to generally as "distribution system") as 100 percent demand related and FERC accounts 369-370 as customer related, while the minimum system approach most commonly classifies FERC accounts 364-369 as both demand and customer related. PSNH's minimum system COSS classifies meters and service lines, FERC accounts 369 and 370, as 100 percent

[64] *See* Charles R. Phillips Jr., *The Regulation of Public Utilities* 438 (1993). While this excerpt explicitly address allocation, the concept of dividing costs between classification and allocation is very similar and sometimes used interchangeably.

customer related and classifies transformers, poles, conductors and cables, FERC accounts 364-368, as 7 to 83 percent customer and 17 to 93 percent demand related.[65]

Q. Why is it appropriate to classify distribution system costs as 100 percent demand?

A. There are two main reasons that cost analysts have traditionally found it reasonable to classify the distribution system as 100 percent demand costs. First, distribution system equipment will not be designed or installed if it is incapable of serving peak demand reliably and safely. This indicates that the cost of distribution equipment is caused by the requirement to meet peak demand. As one analyst of cost of service methods put it: "The theoretical basis for (the basic customer) approach is that the distribution system is sized to a certain capacity, that capacity is available to the total population of customers served by a system, and any capacity used by one customer is generally not available to another."[66] That is, from an engineering perspective, the distribution system is designed to meet localized peak demand of a group of customers, and from an economic perspective demand reflects how the system is utilized by customers. Therefore, all distribution costs are more properly classified as 100 percent demand related and not customer related.

A second, similar explanation is that demand costs are the fixed costs that the utility incurs to be ready to provide service. According to Alfred Kahn, a distinguished

[65] See Ms. Nieto's Direct Testimony, Bates 001663, line 1.
[66] Jim Lazar, *Cost Elements and Study Organization For Embedded Cost of Service Analysis: Applicable to the Tucson Electric Power Company* 19 (1992).

regulatory economist, demand costs are those caused by "the utility's readiness to serve, on demand. This readiness to serve is made possible by the installation of *capacity* . . . the fixed, capital costs . . . And the proper measure of that responsibility is the proportionate share of each customer in the total demand placed on the system at its peak."[67] Said another way, it is a customer's demand that causes the fixed costs of the distribution system, not simply the numerical addition of that customer to the system.

Q. Do other regulatory commissions in the United States use the basic customer and energy-related approaches?

A. Yes. In 2000, the Regulatory Assistance Project ("RAP") estimated that approximately 30 electric utilities use methods that do not classify any portion of the distribution system as a customer cost[68], as opposed to the large percentage PSNH is proposing to allocate as a customer cost in this case. I have also testified in a proceeding where a natural gas utility claimed that 19 states utilize the basic customer or peak-and-average approaches (an energy-related approach).[69] This demonstrates that many Commissions use these methods to classify and allocate both electric and natural gas distribution systems throughout the country.

[67] Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions* 95 (1988) Vol. I.
[68] *See* Fredrick Weston, The Regulatory Assistance Project, *Charging for Distribution Utility Services: Issues in Rate Design* at 29 (2000).
[69] *In the Matter of the Application of CenterPoint Energy Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-008/GR-15-424, Rebuttal Testimony of Russell A. Feingold, at Schedule 3 (Dec. 18, 2015). Due to the time intensive nature associated with a review of these estimates, I have not verified either of these estimates by assessing each Commission's order on the subject. I believe that it is reasonable to rely on CenterPoint Energy's survey as demonstrative that a minimum of 19 regulatory commissions use the basic customer or peak-and-average approaches, given that it was provided by a utility in opposition to those methods.

Q. Is the basic customer approach commonly used and supported by reliable references?

A. Yes. NARUC has two references that mention the approach.[70] While the NARUC Electric Manual's discussion of the basic customer approach resides within the marginal cost section of the manual, a similar approach is applied to embedded COSSes throughout the country, as I demonstrate below. In addition, Dr. James Bonbright discusses the basic customer approach in *Principles of Public Utility Rates*.

Q. Are there state commissions that have explicitly discussed the basic customer approach?

A. Yes. Many states have previously discussed the merits of the basic customer and minimum system approaches in orders.

Q. Can you please provide a summary of previous orders that you are aware of that discuss the merits of the basic customer approach?

A. Yes.

First, the Illinois Commission has rejected the minimum system approach numerous times and adopted the Basic Customer approach:

> As it has in the past, see, e.g. Dockets 05-0597, 99-0121 and 00-0802, the Commission rejects the minimum distribution or zero-intercept

[70] *See* National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* (1992) [hereinafter NARUC Electric Manual]; *see also* National Association of Regulatory Utility Commissioners, *Gas Distribution Rate Design Manual* (1989) [hereinafter NARUC Gas Manual]. The NARUC Electric Manual methods discusses a method similar to the basic customer in the marginal cost section on pages 136–146. The NARUC Gas Manual discusses the basic customer approach on page 23.

> approach for purposes of allocating distribution costs between the customer and demand functions in this case. In our view, the coincident peak method is consistent with the fact that distribution systems are designed primarily to serve electric demand.
>
> The Commission believes that attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic. We reject the use of the MDS in this proceeding, and find that ComEd's ECOSS was correct in not reflecting the MDS concept. Accordingly, the Commission rejects the use of IIEC's COSS because it relies on the use of MDS.[71]

The Illinois Commission compared a method similar to the basic customer approach to the minimum system approach and found the basic customer approach to be more reasonable.

The Washington Utilities and Transportation Commission has also addressed the use of the basic customer approach in detail multiple times, as indicated by the following:

> The company proposed to classify distribution costs using the Basic Customer method, which treats substations, poles, towers, fixtures, conduit, and transformers as demand-related. Service drops and meters are classified as customer related. The company put forward this method in lieu of the Minimum System approach it prefers, primarily in the interest of promoting consensus, and because it is compatible with the use of a decoupling mechanism.
>
> Commission Staff and Public Counsel strongly supported the use of the Basic Customer method as an appropriate allocation. Public Counsel recommended that the Commission also consider approving a method similar to that applied in Cause No. U-86-100, whereby distribution costs were considered to have energy-, demand- and customer-related aspects.

[71] Final Order, *Commonwealth Edison Company Proposed General Increase in Electric Rates (Tariffs filed October 17, 2007)*, at 208 (Sep. 10, 2008), Docket No. 07-0566 (Illinois Commerce Commission).

> WICFUR and SWAP recommended use of the Minimum System approach. This would classify most distribution-related costs according to the relative number of customers in a class. WICFUR argued that this method better reflects the fact that a multitude of small customers requires a more extensive distribution system as compared to large customers with the same total energy requirements. Intervenor BOMA contended that the Basic Customer classification for distribution costs deviates from standard regulatory practice, and pointed out that other generally accepted methods would show commercial customers in a more favorable light in terms of the class' revenue-to-cost ratio.
>
> The Commission finds that the Basic Customer method represents a reasonable approach. This method should be used to analyze distribution costs, regardless of the presence or absence of a decoupling mechanism.
>
> We agree with Commission Staff that proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals.[72]

Iowa has made an approach similar to the basic customer approach the law. Iowa law states that "[c]ustomer cost component estimates or allocations shall include only costs of the distribution system from and including transformers, meters and associated customer service expenses."[73]

[72] Ninth Supplemental Order on Rate Design Issues, *Petition of Puget Sound Power & Light Company for an Order Regarding the Accounting Treatment of Residential Exchange Benefits*, (Aug. 16, 1993) Docket No. UE-920433 (Washington Utilities and Transportation Commission) (1993 WL 13812140), at 5–6.
[73] Iowa Admin. Code 199-20.10(2)(e).

Connecticut has a similar law related to the fixed charge. Specifically, the law states that a public utility's fixed charge shall "recover only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service."[74] This law speaks directly to the how the fixed charge is set, as opposed to how the COSS classifies distribution system costs, demonstrating that the basic customer approach can be utilized for rate design purposes.

The California Commission also uses a form of the basic customer approach. The California PUC has stated:

> We prefer the approach of identifying specific equipment as access related and assigning the investment costs directly to the appropriate customer class. While there is not a clear line of distinction between demand and customer related equipment, we believe the [Transformers, Services, and Meters] method provides us with the best approximation. Accordingly, we will treat the remaining common distribution costs as demand-related.[75]

The Idaho Commission moved from the minimum system approach to the basic customer approach in 1998 because it found that the basic customer approach was a superior methodology.[76]

[74] *See* https://law.justia.com/codes/connecticut/2015/title-16/chapter-283/section-16-243bb/

[75] Interim Opinion, *Re San Diego Gas and Electric Company*, (Dec. 19, 1988), Decision 88-12-085 (California Public Utilities Commission), (1988 WL 1663871), at 15.

[76] Order No. 28097, *In the Matter of the Application of the Washington Water Power Company (Now Avista Corporation dba Avista Utilities—Washington Water Power Division) For an Order Approving Increased Rates and Charges for Electric Service in the State of Idaho*, at 24–27 (July 29, 1999), Case No. WWP-E-98-11 (Idaho Public Utilities Commission).

Rhode Island does not require the minimum system approach and has not since at least 1984 according to the following:

> Both the Navy and TEC-RI requested that the Commission require a Minimum System Study prior to the next case to allocate costs to demand and customer components. The Division recommended that the Commission reject this request. The Commission is satisfied by Dr. Swan's reasoning that it deny the request for a minimum system study and as such, rejects the request. This is consistent with the Commission's previous ruling in In Re: Narragansett Electric Co., Docket No. 1606/1692, Order No. 11227 (issued April 30, 1984) at p.7.[77]

Maryland PUC assessed the minimum system approach and instead uses a method similar to the basic customer approach for both electric and natural gas utilities as indicated by the following:

> As noted above, MEG proposed that a portion of distribution lines, for both gas and electric, should be partially allocated to customer-related costs, whereas OPC and the Company classify mains solely as demand-related. MEG advocated partial allocation to customer-related costs under a minimum cost of service methodology, whereby any such service requires at least a hypothetical minimum size line or pipe to provide service, which hypothetical minimum size service should be classified as a customer-related cost. MEG witness Baudino further argued that interruptible gas customers do not receive proper cost credit or cost allocation under the BGE methodology, as the NCP allocator for cost of mains gives insufficient credit to interruptible customers who do not have the same reliability as firm customers and therefore should not receive a full share of the distribution main costs.
>
> OPC and BGE opposed MEG's request. Company witness Pleat stated the main investment in the BGE system is sized according to the area-wide peak load demand consisting of a mix of specific customer demand profiles, not according to a hypothetical construct

[77] Decision and Order, *In Re: The Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electic[sic] Base Distribution* Rates, at 142 (April 29, 2010), Docket No. 4065 (State of Rhode Island and Providence Plantations Public Utilities Commission).

> of connecting customers to the main grid. In response to Mr. Baudino's contention that interruptible gas service customers receive insufficient credit on cost allocation, Mr. Pleat noted the Commission has approved BGE's narrowing the NCP peak-hour demand allocator from an annual examination to a winter-only examination (November to March), which excludes any impact of potential growth in summer interruptible service that may otherwise become a cost driver for interruptible customers as the economy begins to strengthen in the future. Therefore, interruptible service customers would receive a cost break by having their class peak load observed only during the winter period in the event their interruptible service summer growth increases.
>
> We find no grounds to re-allocate lines as customer-related under a minimum cost of service methodology as advocated by MEG. This proposal has not been accepted in the past by the Commission, and we are not inclined to do so now. MEG's complaint with respect to over allocation of costs to interruptible customers also is reminiscent of its similar complaint in a previous gas case (Case No. 9036), and it was rejected there. We note that interruptible customers already benefit from lower rates, and find no grounds to adjust allocations as argued by MEG.[78]

The Arkansas Public Service Commission has also ruled against the minimum system approach and for the basic customer approach on numerous occasions as indicated by the following:

> The Commission agrees with EAI, Staff and AG that accounts 364-368 should be allocated to the customer classes using a 100% demand methodology and find that AEEC and HHEG do not provide sufficient evidence to warrant a determination that these accounts reflect a customer component necessary for allocation purposes.[79]

[78] Order No. 83907, *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base* Rates, at 81–82 (March 9, 2011) Case No. 9230 (Public Service Commission of Maryland) (internal citations omitted).
[79] Order, *In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service*, at 124–26 (Dec. 30, 2013) Docket No. 13-028-U (Arkansas Public Service Commission).

In addition, the Texas Public Utilities Commission has stated that "[s]pecifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service."[80] It has also found that "[i]t is appropriate to use a 100% demand allocator for distribution accounts 364 through 368," which is consistent with an application of the basic customer approach.[81]

Q. Are you familiar with how Commissions in Minnesota and Wisconsin utilize the minimum system and basic customer approaches?

A. Yes. I worked in Minnesota for five years and testified on the COSS and rate design numerous times. I have also reviewed numerous documents and orders from Wisconsin. Both the Minnesota and Wisconsin Commissions have used the basic customer approach to inform their decisions.

Recently, Xcel Energy's subsidiary, Northern States Power Wisconsin ("NSP-W"), was ordered to file a COSS that utilized the basic customer approach, which the Wisconsin Public Commission ("WPS") used to set rates.[82] Specifically, in NSP-W's recent rate case the Company was required by WPS staff to produce a new COSS using a 100 percent demand classification for the distribution system. WPS then continued its

[80] Order No. 40, *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344*, at 6 (Nov. 22, 2000) Docket No. 22344 (Public Utility Commission of Texas).
[81] Order, *Application of AEP Texas Central Company for Authority to Change* Rates, at 17 (Dec. 13, 2007) Docket No. 33309 (Public Utility Commission of Texas).
[82] Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates, Docket No. 4220-UR-121, FINAL DECISION at 39 (Wis. Pub. Svc. Comm'n Dec. 23, 2015).

long-standing practice of setting rates using a range of COSS models that included the 100% demand classification.

As for Minnesota, the Commission has considered COSSs that classify the distribution as 100 percent demand-related as well as ones that classify a portion as energy-related for natural gas and electric utilities. In one case, the Minnesota Commission found that:

> The OAG showed that there are several methods, including the minimum system, basic customer, and peak-and-average methods, for classifying and allocating distribution system costs. The Commission finds merit in each theory.
>
> . . .
>
> The Commission is persuaded, on valid theoretical grounds, that the minimum system studies over-allocate distribution costs to the customer component. Other class-cost-of-service studies suggest that the over-allocation to the customer component may be significant.[83]

In another case, the Minnesota Commission stated:

> the Commission also concurs with the OAG on the merits of considering more than one cost study (including the basic customer COSS).
>
> The Electric Manual indicates that no single cost study method can be judged superior to all others in all contexts, and the choice among methods is fraught with disputes over assumptions, applications, and data.[84]

[83] *In the Matter of the Application of CenterPoint Energy Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-008/GR-15-424, Findings of Fact, Conclusions of Law, and Order 53 (June 3, 2016).
[84] *See* Findings of Fact, Conclusions, and Order, *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rate for Electric Service in Minnesota*, 62. Docket No. 15-1033 (May 1, 2017).

As demonstrated by these excerpts, it is common practice for both Minnesota and Wisconsin Commissions to consider the basic customer approach and even energy-related approaches.

Q. Why is this information important for the Commission to consider?

A. I have provided information from twelve commissions related to both vertically integrated and restructured electric utilities that support my recommendation to utilize the basic customer ACOSS. I have not, however, conducted an exhaustive survey of all states nor do I constantly monitor each state for updates.

I believe that these twelve jurisdictions are sufficient to demonstrate the point that I wish to make: Other regulatory commissions have recognized the reasonableness of the basic customer approach. Having reviewed these orders, I find their reasoning applicable to this case and persuasive. I recommend the Commission apply the basic customer approach and require distribution accounts FERC account 364-368 to be classified as 100 percent demand related.

Q. How do the results of PSNH's proposed ACOSS change when the basic customer approach is employed?

A. Changing a single assumption—using the basic customer approach—has a significant impact as seen below.

Table 1: Required Change in Rates per the ACOSS, under Different Approaches[85][86]

****Begin Confidential****

	Total Retail	R PL+TOD	R LCS	RWH	GPL+TOD	G SH	G LCS	G-WH	GV	LG	RATE B	OL	EOL
Minimum System Approach	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Basic Customer Approach	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

****End Confidential****

Table 1 demonstrates that one assumption reduces the residential class's revenue deficiency by over half.

2. *PSNH's Minimum System Study*

Q. What is the minimum system approach?

A. The minimum system approach reasons that the distribution system includes both demand and customer costs. Specifically, it reasons that distribution costs incurred to provide capacity in the distribution system are caused by peak demand and should therefore be classified as a demand cost. It also reasons that other distribution costs are caused by the need to connect customers to the distribution system. To identify these customer costs, the minimum system approach attempts to isolate a theoretical "minimum system," which is a hypothetical distribution system for the utility that has little or no capacity. Because this minimum system has no capacity, it presumably includes only the costs needed to connect each customer. The customer cost varies

[85] See CONFIDENTIAL Attachment OCA 2-052 A.
[86] *See* CONFIDENTIAL Attachment OCA 8-043.

generally with the number of customers under the minimum system approach. The cost of the minimum system can be estimated in several ways.

Q. How is the cost of a minimum system estimated?

A. There are two common methods to estimate the minimum system: the minimum size and zero intercept methods.

At a high level, the minimum size method creates a minimum system using the average book unit installed cost of the smallest distribution equipment installed and multiplies this unit cost by the total number of distribution equipment on the system. Take transformers for example. The first step of the minimum size method is to determine the average book unit installed cost of the smallest transformer on the distribution system. The second step is to determine how many transformers are installed on the distribution system. The third step is to multiply these two numbers together—this number is the cost of the minimum system. Lastly, the cost of the minimum system is compared to the total cost of transformers on the distribution system—creating a ratio of customer and demand related transformer costs.[87]

The zero intercept method can also be used to estimate the minimum system associated with transformers. At a high level, the zero intercept method utilizes econometric regression analysis to estimate the "zero or no load" unit cost of each type

[87] The NARUC Electric Manual discusses the minimum size method on pages 90-92.

of distribution system equipment. The first general step of the zero intercept method requires gathering and cleaning cost data. Second, a regression is run on the data. Third, the constant coefficient estimated in the regression is assumed to be the unit cost of a no load transformer. Lastly and like the minimum size method, the no load transformer cost is multiplied by the total number of transformers to come to the customer related portion of transformer costs.

It is important to understand that, while methodologically distinct, at their core, the minimum size and zero intercept methods are simply approaches to do the same thing; that is, to estimate the cost of the minimum system.[88] However, because the minimum size method estimates the minimum system using distribution equipment with some load (i.e. because the smallest equipment still serves load) and the zero intercept theoretically estimates a no load scenario, the minimum size method should result in a higher, over-estimated percentage of customer costs.

Q. Do you believe that the minimum system approach is a reasonable way to classify distribution system costs?

A. There are many recognized approaches to classify distribution system costs, and each approach has a logical argument to support it. With this said, I find the minimum system approach to be the least reasonable way to classify distribution system costs.

[88] The NARUC Electric Manual discusses the zero intercept method on pages 92-94.

Q. Why do you find the minimum system approach the least reasonable way to classify distribution system costs?

A. While the minimum system approach is based on what RAP has characterized as a "certain intuitive appeal," the method requires the analyst to create a hypothetical, no-capacity system—something that is not real and not directly based on system characteristics.[89] To create this imaginary minimum distribution system, analysts must make numerous subjective assumptions that oversimplify system engineering and assign costs based on questionable cost causative principles. This is different than the basic customer approach, which relies more heavily on actual system data. Since utilities have an economic incentive to over-classify customer costs, the subjective decisions made by utilities can lead to increased customer cost classification.

Q. Why are the subjective decisions of the minimum system approach problematic?

A. It is important to understand that, while the minimum system approach has a basic intuitive appeal, many of the decisions it requires analysts to make have no clear support one way or the other. Different utilities, therefore, make different strategic choices at these decision points, and then present arguments to justify a methodology—PSNH is no exception as I detail below.

[89] *See* Fredrick Weston, The Regulatory Assistance Project, *Charging for Distribution Utility Services: Issues in Rate Design* at 30 (2000).

Q. Has any credible authority analyzed the different approaches of classifying and allocating the distribution system?

A. Yes. I have identified four significant analyses that evaluated the minimum system approach to some extent. The analyses, and controversy associated with the minimum system approach, goes back at least to Bonbright's seminal work, *Principles of Public Utility Rates*, in 1961. The other analyses were conducted by research consultants or RAP.[90]

Q. What conclusion did Bonbright come to 1961?

A. Bonbright did not oppose the theory of developing a hypothetical minimum system. He recognized that it was appropriate to classify any distribution costs above the hypothetical minimum system as demand costs. But Bonbright rejected the notion that the costs of this hypothetical minimum system should be classified as customer costs, concluding that doing so is "clearly indefensible."[91] Bonbright's primary concern was that the minimum system analysis does not consider population density of a service territory, even though population density is vital in determining the cost of providing service to additional customers:

> What the (minimum system) imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this

[90] *See* Fredrick Weston, The Regulatory Assistance Project, *Charging for Distribution Utility Services: Issues in Rate Design* (2000); Jim Lazar, *Cost Elements and Study Organization For Embedded Cost of Service Analysis: Applicable to the Tucson Electric Power Company* (1992); and Jim Lazar and Wilson Gonzalez, Regulatory Assistance Project, *Smart Rate Design For a Smart Future* (2015).
[91] James C. Bonbright, *Principles of Public Utility Rates* 348 (1st ed. 1961).

> system. For it makes no allowance for the density factor . . . Indeed, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[92]

Bonbright simply observed that if a person is added to an existing minimum distribution system, for reasons such as urban infill, there would be *de minimis* increase in minimum distribution system costs. Therefore, the minimum distribution system is not caused by the number of customers.

a) Analysis

Q. Did you analyze PSNH's minimum system study methodology and results?

A. Yes.

Q. Please describe PSNH's minimum system study methodology.

A. Witness Nieto first identified the minimum sized conductor, transformer, and pole currently installed on PSNH's primary and secondary distribution systems. Then Witness Nieto determined the installed cost per unit of the minimum sized plant identified. To do so, Witness Nieto consulted with the Company's engineering group to find the current costs of material, labor, and equipment.

Witness Nieto then multiplied the current installed cost per unit of the minimum sized plant by the total inventory of each plant type. The product of the two is the portion of the total plant account costs (separately inventoried and converted to 2018

[92] James C. Bonbright, *Principles of Public Utility Rates* 348 (1st ed. 1961).

dollars) that is classified as customer cost. The remaining portion is classified as demand cost.

Q. Do you have concerns with PSNH's minimum system study?

A. Yes. I am concerned by a number of the subjective decisions PSNH made in its minimum system study. I will explain each of the following issues in more detail below:

- PSNH claims to follow the instructions of the NARUC Electric Manual but does not do so.
- PSNH's inclusion of primary distribution system components in the minimum system study contradicts cost causation theory.
- PSNH selects the currently-installed minimum size of each distribution element, rather than a historically-representative minimum size.
- Most concerningly, PSNH uses an inappropriate and misleading measure of the cost of each minimum-sized element.

Q. Did PSNH claim to follow the steps described in the NARUC manual?

A. Yes. In direct testimony, Witness Nieto states that the minimum system study follows the steps "described on pages 90-92 of the NARUC manual."[93] In OCA 7-003, Witness Nieto reiterates that the Company followed "the general method identified in the NARUC manual."[94]

---

[93] See Ms. Nieto's Testimony, Bates 001662, lines 3-4.
[94] See Schedule REN-3.

Q. Did PSNH follow the explicit steps described in the NARUC manual?

A. No, the Company did not follow NARUC's instructions for conducting the minimum size method. NARUC instructs that "normally, the average book cost for each piece of [minimum size] equipment determines the price of all installed units."[95] PSNH's study does not use the average book cost of existing minimum size equipment; instead, it uses the Company's current installation cost for new equipment.

Q. Please explain why classifying primary distribution system as a customer cost does not align with cost causation?

A. The classification of primary distribution system as a customer cost is a good example of where the NARUC Manual clearly contradicts itself. On the one hand, the NARUC Manual defines customer costs as those "that are directly related to the number of customers served."[96] On the other, it suggests classifying primary distribution system costs as customer related.

It is laughable to suggest that the number of customers impacts a 34,000-volt primary distribution line. Primary distribution lines are sized to meet peak load—the number of customers downstream is not an explicit factor. This is because 100 customers could require a 34,000-volt line or 25,000 customers.

[95] NARUC (1992). p.90.
[96] NARUC (1992). P.20.

Even utilities have found the assumption that high voltage lines are customer-related to be unpalatable. Specifically, Oklahoma Gas and Electric does not classify primary distribution system costs as customer related within its minimum system study.[97]

Nonetheless, PSNH classified its primary distribution system as up to [redacted] customer related,[98] which is equivalent to claiming that adding individual customers is the root cause behind [redacted] of the costs associated with primary distribution. This is a completely illogical result of PSNH's minimum system study.

Q. Does PSNH select a historically representative equipment size as the minimum size for each distribution element?

A. No. PSNH has chosen a minimum size for poles, lines, and transformers that fails to reflect the infrastructure installed on its system.

Q. Please provide an example.

A. For FERC account 364, the Company determined the minimum size pole to be 45 feet on the primary system and 35 feet on the secondary system.[99] Based on the Company's plant accounting data, it actually has poles as small as 25 feet on both the primary and secondary systems. On the primary system, poles that are smaller than PSNH's chosen minimum size (those that are 25, 30, 35, and 40 feet) make up 85 percent

[97] *See* CAUSE NO. PUD 201700496
[98] *See* CONFIDENTIAL Data Request Response OCA 2-052 A.
[99] *See* Schedule REN-4.

of the total count of pole heights. On the secondary system, poles that are smaller than PSNH's chosen minimum size (those that are 25 and 30 feet) make up 61 percent of the total count of pole heights.[100] This means that a *majority* of the poles on both the primary and secondary systems are in fact smaller than what PSNH has selected as the "minimum" size pole.

Q. What might be a consequence of this size discrepancy?

A. Assigning the cost associated with a larger-than-minimum pole to all poles in an account, when over half of the poles in the account are smaller than that larger pole, could distort the proportion of that account that is called its "minimum system." This would result in an exaggeration of the costs classified as customer rather than demand. If the larger-than-minimum pole is costlier than the many smaller poles it was chosen to represent, it will exaggerate the amount of the account classified as demand, disproportionately assigning that account as customer costs, when in fact they should be demand. This inaccuracy could have consequences for ratepayers across PSNH's territory.

Q. Does the NARUC manual suggest using currently installed poles?

A. Yes, the NARUC manual suggests using "the minimum height pole currently being installed."[101] Given that this study intends to allocate embedded costs, using currently installed poles does not make logical sense. This is another area where the

[100] *See* Schedule REN-5.
[101] NARUC (1992). p.91.

NARUC Manual does not provide clear direction on the minimum system study and has been acknowledged as an issue by other independent analysts.[102]

Q. Please describe the Company's subjective decision to use current installation costs to calculate the minimum system costs.

A. PSNH uses the current cost for new equipment (of the aforementioned "minimum" size) to represent the minimum cost applied to all the infrastructure in a particular account, although the units in those accounts have been installed over the past century. The minimum system study multiplies that "minimum" cost by the total number of items in an account, to calculate the system costs that will be classified as customer costs.

PSNH chooses to use present-day hours, rates, and loaders for the present-day labor, equipment, and materials of its distribution infrastructure. Using current costs as a measure of the historic cost of an investment is inappropriate. Not only is it inappropriate, I have reviewed dozens of these studies and have never seen a utility use this method.

Q. What is your concern with the Company's subjective decision?

A. Any of the individual cost drivers – if not all of them – could have changed over the decades that each distribution component has been installed and in service.

---

[102] *See* Fredrick Weston, The Regulatory Assistance Project, *Charging for Distribution Utility Services: Issues in Rate Design* (2000).

Incongruously applying a unique present cost to old infrastructure inevitably obscures the true cost of that infrastructure. Indeed, PSNH uses the original cost of the infrastructure (updated with the Handy Whitman index) to calculate the current cost that must be recovered for each FERC account. This cost is what the minimum study is intended to classify into demand and customer categories.

The Company highlights its own methodological inconsistency, claiming in discovery that its "process creates a minimum size cost that is current and not distorted by vintage of installation," which "allows for a comparison of total plant cost by FERC account with the typical installed cost of the minimum sized equipment."[103] In reality, the Company's method *distorts* costs by erasing the vintage of installation—it's an embedded cost analysis that is being conducted. And the Company's method *prohibits* comparison by using a different metric to establish total plant costs as it does to establish the cost of minimum sized equipment. Using a new cost for old investments and then comparing that to the old cost of those investments is egregious.

Q. What costs are commonly used by utilities?

A. Utilities do not adhere to any objective approach—which is the point. Instead, they often use "innovative" techniques. However, most utilities try to use FERC data that is not transformed cost data in an ad hoc manner, as PSNH has done.

The NARUC manual specifies that average installed book cost be used.

[103] See Schedule REN 3.

Q. Did you request that Witness Nieto provide the average installed book cost in the context of the minimum system study?

A. Yes. Witness Nieto provided a raw measure of average historic book cost that was "unadjusted" and impossible to use as a replacement for the minimum size cost the Company applied in its MS study.[104]

Q. Is PSNH's minimum system study reliable as a method of classifying distribution system costs?

A. No. Not only is the minimum system method an unsatisfactory approach in general – as I argue at length in earlier sections – but PSNH's minimum system study is particularly unacceptable for the reasons I described previously.

D. Additional ACOSS Analysis

Q. Do you have additional issues with the ACOSS to address?

A. Yes. I have two additional topics to address. First, I provide observations related to PSNH's proposed hybrid allocator that is used to allocate the cost of distribution substations. Second, I discuss the subfunctionalization of distribution system costs.

Q. Please describe how the Company's new approach to subfunctionalizing distribution system costs impacted cost allocation.

[104] *See* Schedule REN-6.

A. The Company has subfuctionalized the distribution system into three- and single-phase equipment. The implication of this change is that taking service at the three-phase level of the system will not be allowed single phase system costs. This primarily reduces the costs allocated to large customers.

Q. Do you find this change appropriate?

A. Subfunctionalization is common in many cost studies. However, the theory that supports this allocation approach is not as accurate as it once was. Traditionally, the justification for not allocating costs that are downstream from a customer was because power only flowed in one direction.

Today, according to PSNH, the Company is preparing the system for two-way power flows to create the "platform of the future." Platforms do not have one-way flows so the cost causation will be different on modern power systems. For example, the Company is installing equipment to update the system for backward power flows. This equipment protects the customers upstream—unlike traditional investments. For this reason, the sharing downstream costs is more reasonable with a modern a grid.

Q. Please describe the hybrid cost allocator that the Company proposed.

A. The Company has proposed a demand allocator that has two components. The first is based on the 20 highest system peaks. The second component is based on non-coincident peak demand. The hybrid demand allocator is a 50/50 marriage of the two components. The hybrid allocator is used to allocate distribution substation costs.

Traditionally, non-coincident peak demand allocators have been used to allocate this equipment.

Q. Do you agree with the use of the Company's hybrid cost allocator?

A. Not entirely. There are a few shortcomings associated with the Company's hybrid allocator. The primary shortcoming is that using the 20 highest system peaks does not align with the cost causation of numerous substations. Of the Company's substations, approximately 10 percent peak in the winter but the 20 highest peaks occur during the summer.[105] Given that substation sizing is determined by downstream (i.e., towards the customer), customers that peak during the winter are not being assigned a fair amount of costs.

Q. Do you agree with any concepts that the Company is integrating into the hybrid allocator?

A. Yes. The Company is suggesting that multiple peaks be used to determine more appropriate cost allocations. I agree with this conceptually. Traditionally, cost allocators over-emphasize the importance of single peak. Systems are not sized to meet one peak but a limit number of unusually high peaks. This concept will be particularly important when, and if, DER penetrations increase. At that point, even more detail of the peaks should be incorporated in cost allocators, such as how long peaks last.

[105] *See* Schedule REN-7.

E. ACOSS Recommendations

Q. What are your recommendations for the ACOSS

A. The Commission should use the results of the basic customer ACOSS to inform revenue apportionment. As I explain later in my testimony, the basic customer ACOSS should also be used to inform rate design. Finally, the Commission should require the Company to continue providing an ACOSS, as it provides useful information for revenue apportionment and rate design.

VI. MARGINAL COST OF SERVICE STUDY

A. Background and Objectives

Q. What is an MCOSS?

A. An MCOSS is used to determine the portion of demand and customer related cost on the distribution system costs for which each customer class is responsible, and the way that the classes will pay those costs. An MCOSS does so by identifying the incremental costs to serve additional demand or customers on a distribution system. This contrasts with an embedded cost study, which uses historic investments to determine cost allocation.

Q. What is the purpose of an MCOSS?

A. An MCOSS provides information that can be used to allocate the revenue requirement to customer classes and inform rate design.

The marginal cost approach is particularly recognized for its economic efficiency: economic theory holds that in a competitive market, a supply-demand equilibrium reflects consumers' willingness to pay for service at the utility's cost to produce that service. Under a regulated monopoly, rates equal to the utility's cost to serve the incremental level of output demanded by customers are seen as achieving the most efficient allocation of resources and appropriately informing consumption decisions.[106]

Q. Is there a standardized approach to conducting a distribution MCOSS?

A. No. There are multiple common approaches to conducting a distribution MCOSS, but no standardized approach. The overall process is similar in concept, requiring analysts to distinguish between demand-related and customer-related distribution costs in order to calculate the marginal cost of additional demand and of additional customers. However, the methods of calculating the incremental dollar impact of each vary across and within jurisdictions.

Q. What are some of the common ways of calculating marginal demand-related distribution costs?

A. There are multiple ways, of which I'll explain three.

A planning, or future costs, approach is forward-looking. It identifies future distribution costs that are directly related to expected load growth – specifically to noncoincident system peak – over a particular time horizon[107]. These planned expenses

[106] National Association of Regulatory Utility Commissioners (NARUC), Electric Utility Cost Allocation Manual (1992). p.14.
[107] NARUC (1992) at 137.

and investments are divided by load growth in order to calculate a marginal dollar per kilowatt cost.

A projected embedded approach uses historic system cost trends to predict future marginal costs. It relates annual data on noncoincident peak load growth to annual load-related distribution infrastructure costs (adjusted to current dollar value). One way to relate that load growth to load-related costs is by performing a least-squares regression.

There are different approaches and regression specifications used. NARUC has observed that system investments tend to be "lumpy," meaning that investment occurring in one year is not the only related load growth in that year. Therefore, "the best regression results are achieved by using least squares and regressing cumulative incremental investment against cumulative incremental load."[108]

An alternative projected embedded analysis uses the same historic load growth and inflation-adjusted cost data, but, instead of using regression, simply divides the investments by load growth to find the dollar-per-kilowatt marginal figure.

Q. Does the approach used to estimate marginal costs impact the results?

A. Almost certainly. It would be highly unlikely to conduct three different MCOSSes using three different approaches and get the same, or potentially even similar, results. In fact, having two analysts use the same approach would likely lead to

[108] NARUC (1992) at 129.

different results. Due to the magnitude of assumptions that need to make for each approach and the importance of some assumptions, the results from different approaches and analyst very significantly.

Q. How might Commissions mitigate the effect of bias influencing MCOSS methodological choices?

A. Due to the various approaches and subjective decisions possible, it is good practice to evaluate numerous COSSes and conduct sensitivity analysis around key assumptions.

B. PSNH's MCOSS Approach and Results

Q. What is PSNH's MCOSS used for?

A. PSNH's MCOSS is used to inform the Company's rate design.

Q. Please summarize PSNH's MCOSS approach.

A. The Company's MCOSS is intended to identify the incremental cost to the Company of serving the next unit of demand or providing customer access to the grid. In its MCOSS, PSNH calculates 1) "marginal, time-related upstream delivery costs" related to growth in expected station peak loads, 2) local distribution facilities costs associated with customers' long-term maximum demand, and 3) customer-related costs of service drops, meters, O&M, and other customer services.

Q. How did Witness Nieto calculate the cost of incremental peak demand?

A. PSNH uses the planning approach to calculate incremental peak demand.

Q. Does Witness Nieto include an additional approach to calculating demand-related marginal costs?

A. Yes, Witness Nieto has created the concept of "design demand" in order to collect customer demand costs through a fixed monthly charge on customer bills, referred to as local distribution facilities costs.

Q. How did Witness Nieto calculate the cost of incremental customer connections?

A. Witness Nieto calculates a levelized annual cost for the capital components of serving each new customer, adds customer service and O&M expenses, and applies these to all customers on PSNH's system.

Q. What data did Witness Nieto use for inputs to the MCOSS?

A. Data and the associated planning and data cleaning approaches were provided by the Company.

Q. Was there anything unique about the data provided to Witness Nieto?

A. Yes. In July of 2018, the Company filed an MCOSS in the Net Energy Metering ("NEM") proceeding, DE 16-576.[109] A short time after filing the MCOSS in the NEM proceeding, the Company filed the MCOSS for this rate case. The underlying data and

[109] *See* Schedule REN-8.

assumptions used for the two studies changed dramatically over this brief period of time. The Company changed planning assumptions used to form data inputs, changed cost classifications for determining which costs are marginal (as opposed to sunk costs, which should not be in a marginal cost study), and selectively chose to incorporate some, but not all, inputs from its ACOSS. These changes led to significantly different marginal cost results.

Q. Did the Company explain the impact that the changes it made to the NEM MCOSS had on the 2019 MCOSS in this docket?

A. No. The Company did not provide information in its direct testimony nor in original attachments in this docket as to how the recently changed assumptions impacted the filed model.[110]

C. Analysis

Q. How is this section of your testimony organized?

A. I begin this section with a comparison of the data and assumptions between the NEM and rate case MCOSSes to demonstrate the influence that information asymmetry had on the results of the MCOSS. In Section 2, I discuss the shortcomings of Witness

[110] The Company filed its MCOSS testimony and an explanatory attachment on May 28, 2019, neither of which mention the changes from the NEM proceeding. The Company simultaneously filed that same attachment in the NEM docket DE 16-576, with two additional cover pages that list some of the altered assumptions between the two models. Those changes do not appear to have been entered into the record in the rate case docket DE 19-057. Only upon discovery request did the Company provide a list of changes in this proceeding – several of which they had not disclosed even in the NEM docket. The Company only provided the quantitative impacts of a few of the altered assumptions on the final marginal cost calculations. *See* Attachment MCOSS-1 in DE 19-057, filed May 28, 2018. *See* Eversource Energy Updated Marginal Cost of Service Study in DE 16-576, filed May 28, 2019.

Nieto's marginal customer cost calculation. In Section 3, I discuss the concept of design demand, which Witness Nieto has utilized to justify additional fixed cost recovery for utilities.

1. The Importance of Data and Assumptions

Q. Do you have concerns when comparing PSNH's recent MCOSSes?

A. Yes. The two marginal cost studies are dramatically different, even though they were filed less than a year apart. Specifically, the Company noticeably reduced its capacity-related capital budget when updating the MCOSS for this proceeding. As a result of the lower capacity-related station costs, the study produces a lower marginal volumetric cost of electricity, which also leads to higher fixed monthly charges. These changes align with aforementioned utility economic incentives.

It is deeply concerning that the Company would put forth such different versions of an MCOSS, so close to one another. Numerous inputs have changed without explanation, many of them through subjective assumptions. The extent of the change seems to suggest that at least one of the studies is staggeringly inaccurate, or the Company is acting strategically for financial gain. Either of these explanations discredits the results of the Company's MCOSS.

Q. What specific changes do you take issue with between the two studies?

A. After I issued discovery, the Company disclosed the numerous differences between the NEM and rate case MCOSSes. The Company provided a long list of changes that does not appear to be exhaustive.[111] I do not cover each of these changes. I focus on each of the following changes below:

- The Company reclassified the entire station budget item "Anticipated Transformer Replacement", thereby shifting 44 million dollars away from capacity constraint and toward asset condition. Those $44 million were completely removed from the study, as the Company considered them sunk costs that are irrelevant to MCOSSes.
- PSNH has chosen, without explanation, to use entirely different criteria in this proceeding for determining when the Company must expand a non-bulk station transformer.
- PSNH has determined – in this proceeding, but not in the NEM proceeding – that load can be switched off to a nearby non-bulk substation to prevent another station from exceeding its LTE (long-term emergency) rating. This is a basic engineering concept and it is unclear why such an assumption would change within months.
- The Company has updated its proposed time of use periods with changes that do not improve their representation of hourly load data.

[111] *See* Schedule REN-8, in which the Company states, "[t]he main changes were to the bulk and non-bulk capital budget. The following are a list of these changes as well as other updates," failing to confirm that the list is exhaustive.

- The Company has updated class weighting factors for customer accounts expenses and customer service and informational expenses, causing dramatically different results for weighted expenses in the two studies.

Q. How does PSNH's 2019 MCOSS differently classify anticipated transformer replacement costs?

A. In 2018, the Company classified anticipated transformer replacement investments as capacity related. These investments totaled $44 million over 2021-2023. According to discovery, "the dollar amounts were not tied to any specific locations."[112] In 2019, the Company decided that those investments were no longer capacity-related but were instead intended to address asset conditions. Evidently "the Company clarified that it will not address all the identified N-1 violations." The Company's explanation for altering the classification is lacking for two reasons.

First, the Company did not provide any objective analysis to support the change. This suggests that the Company's classification change was purely subjective in nature. Given the significant impact this assumption had on the estimate of marginal cost (a 68 percent reduction from $112.50/kW to $36.30/kW),[113] it provides an excellent example of why sensitivity analysis should be conducted on sensitive and extremely subjective assumptions.

[112] *See* Schedule REN-8.
[113] *See* Schedule REN-9.

Second, given that the investments were not directly tied to a location, it is unclear why the Company's clarification regarding N-1 violations would impact this assumption. Just because the Company is not addressing *all* N-1 violations, should not necessarily eliminate a $44 million budget.

Regardless of the Company justification for this change, the lack of transparency with which it was made and the impact it has on the model is extremely concerning. The impact of PSNH's assumptions aligns with an economic incentive for profit maximization: when tens of millions of dollars are no longer considered capacity-related, the five year system-wide average bulk station marginal cost falls, in turn causing lower volumetric rates and increased fixed customer charges. As discussed throughout my testimony, this is a common theme in both the cost studies submitted: PSNH is making or changing assumptions to justify increase fixed cost recovery.

Q. How does PSNH's 2019 MCOSS differently determine when a non-bulk station upgrade gets triggered?

A. The July 2018 study used nameplate rating to determine when expansion of a non-bulk station is required. The 2019 MCOSS instead uses the transformer's LTE rating to identify needed expansion.

This should be a straightforward planning decision that is easy to justify and applied consistently across a long timeframe. The Company, however, seems to be changing its planning criteria back and forth on short notice, without explanation for doing so.[114] As a result, this subjective decision causes the current share of peak load in capacity expansion substations to fall 76 percent.[115] This result again lowers volumetric rates and raises fixed charges.

The Company gives no reason for this significant methodological shift. If LTE is the proper station expansion criteria, PSNH does not explain why its 2018 MCOSS so thoroughly misrepresented the need for system upgrades.

Q. How does PSNH's 2019 MCOSS differently address options for alleviating substation capacity constraints?

A. The 2019 MCOSS uses "lower cost measures" to solve substation constraints than were used in the 2018 MCOSS. According to discovery responses, discussion with Company planners revealed the option to alleviate a constrained station by switching load to a nearby non-bulk substation.[116]

The measure appears to be another basic planning assumption that should be standard yet was subjectively changed. The Company's sudden, subjective choice to include the measure in the 2019 MCOSS has the same effect of the many decisions already described in this section: it lowered capacity value in alignment with utility economic incentives. It is difficult to understand why the Company would not have identified this measure for the exact same study less than a year earlier.

---

[114] *See* Schedule REN-8.
[115] *Id.*
[116] *Id.*

Q. How does PSNH's 2019 MCOSS differently assign time of use periods?

A. PSNH has updated its proposed peak and off-peak periods "to include actual year 2018 hourly station loads."[117] The changes shift PSNH's 2018 proposed peak period, 12:00 pm-8:00 pm, instead to 11:00 am-7:00 pm. Evidently by including 2018 data, the company found a higher probability of peak falling in hour 11:00 am and lower in hour 7:00 pm. My analysis of actual 2018 data, however, shows that this change improves the time periods very little.

****BEGIN CONFIDENTIAL**** [redacted] ****END CONFIDENTIAL****

---

[117] *Id.*

[118] *See* the Eversource modified response to OCA Data Request OCA 2-051, specifically CONFIDENTIAL Attachment OCA 2-051F.

Q. How does PSNH's 2019 MCOSS differently assign class weighting factors?

A. Between the two filings, the Company updated the class weighting factors for customer account expenses and customer service and informational expenses. Evidently, this was intended to "be consistent with the ACOSS."[119] The changes in weights that the Company implemented caused the Estimated Annual Weighted Customer Service and Information Expense to decrease by 99 percent for the residential class, from $19.99 to $0.16.[120] The reason for this enormous change appears to be that the Company changed its weighted average number of customers significantly. With no explanation, PSNH has placed far greater weight on GV and LG customers – with a particularly high increase for GV – than in the NEM MCOSS. Although each study presents the weighted number of customers for the past four years, these historical numbers differ by two orders of magnitude depending on the MCOSS used. The Company also uses a five-year average in the rate case and two-year average in the NEM proceeding, which is not mentioned in the discovery response requesting comparison of the two. The subjective decision to change these particular weights so dramatically – and not others – is not justified in the company's rate case filing.

Q. Based on the above changes, what do you conclude about PSNH's 2019 MCOSS updates to its 2018 study?

[119] *See* Schedule REN-8.
[120] Importantly, this assumption alters cost allocation, not the magnitude of customer costs, or classification of costs. The assumption shifted costs from the residential customers to other customer classes, but did not lower the number of marginal customer costs under consideration.

A. I conclude the following:

1. Subjective assumptions have radically changed the MCOSS results

In a MCOSS, a utility makes many assumptions that have noticeable impact on the study's results. In 2018 and 2019, PSNH submitted two MCOSSes that differed in a remarkable number of ways. Many of the changes were completely subjective and radically changed the results of the study. These changes consistently altered the model to bolster arguments for increased fixed cost recovery for the Company. Furthermore, the Company did not transparently disclose these changes in this proceeding. It is difficult to construct a scenario in which the Company's actions are not clearly labeled as intentional manipulation of the MCOSS.

2. PSNH should have disclosed the changes in this proceeding

It is disconcerting that PSNH would not plainly divulge these changes in its originally filed testimony and attachments. The Company disclosed many of the changes at the same time in the NEM docket, which means it was quite capable of doing so here as well.

Additionally, PSNH has proven itself attentive to disclosing other changes in this docket. The Company spent several pages of its ACOSS testimony highlighting a change from its prior rate case: its decision to begin using a hybrid class allocator for station plant. The new allocator evidently yielded differences of less than 1 percent for the Residential and General Service rates,[121] and yet the Company ensured that the change was well documented on the record. It is inexplicable that the MCOSS changes would not also be disclosed in this way.

3. At least one of the studies must be inaccurate for the two to be so different

Several of the changes call into question the accuracy of the two MCOSSes. It is hard to imagine why the Company wouldn't have standardized some of the basic system planning decisions, nor why it wouldn't have transparently reported and then justified those changes in testimony. Many changes were unsupported by analysis, and almost all have the same impact of lowering the capacity-related capital budget, in turn lowering the volumetric billing rate and raising fixed customer charges.

2. *Marginal Customer Costs*

Q. What is a marginal customer cost?

A. A marginal customer cost is a cost that varies directly with the addition of a new customer and is independent of costs related to servicing the customer's energy and demand requirements. Marginal customer costs can be divided into two categories; capital investment and O&M. The capital investments relevant to marginal customer costs are meters and service lines. O&M costs that are marginal customer costs are related to meter reading, customer accounts, and customer service.

[121] *See* Ms. Nieto's Testimony, Bates 001666 lines 4-5.

Q. Why are marginal customer costs important?

A. Marginal customer costs are used to inform the customer charges for each of the rate classes.

Q. Please describe how PSNH estimates marginal customer costs.

A. PSNH uses a method referred to as the rental method to estimate the marginal costs associated with capital investments in meters and services. The rental method estimates the cost to connect a new customer with a service line and meter, then, using an economic carrying charge, annualizes these costs for the life of the assets. Finally, these annual costs are assigned to *every single* customer. Therefore, PSNH's rental method assigns annual marginal connection costs to every customer on the system, regardless of whether they are a new customer.

Q. Do you agree with PSNH's use of the rental method?

A. No. The rental method does not accurately estimate marginal costs, for a variety of reasons. First, the rental method is based on a flawed theoretical premise that results in an estimate of value instead of marginal costs incurred by the utility. Second, by including sunk costs in the estimation of marginal customer costs, the rental method more resembles an embedded cost approach than a marginal cost approach. Third, PSNH's application of the rental method includes replacement costs, which are not growth related and, therefore, should not be included in marginal customer costs. Lastly, the rental method ignores depreciation by being insensitive to the age of the assets. The result of these issues is an over-estimate of marginal customer costs. I will discuss each of these shortcomings in more detail.

Q. Why is the theory that the rental method is based upon flawed?

A. The rental method is based on the premise that there is a competitive rental market for meters and services. The theory suggests that a consumer would be willing to pay an annual rental fee for meters and services. Using an annual rental fee, however, results in an estimate of value as opposed to the actual marginal costs incurred by the utility. In a competitive market, which a marginal cost study should be attempting to mimic, consumers do not pay value—consumers pay cost. Because the rental method estimates value instead of marginal costs, it over-estimates marginal customer costs.

Q. What is another reason that the rental method over-estimates marginal customer costs?

A. The rental method assigns sunk costs in the form of meter and service investments to each customer on the system, instead of estimating the marginal cost of connecting new customers. The Company is assigning meter and service costs that have already been incurred by the Company (i.e. sunk costs), and should no longer be considered for pricing future service.

Q. How does the rental method include sunk costs?

A. The rental method includes sunk costs by assigning a "rental fee" to each and every customer on the system. This process treats every customer on the system as though they are being connected to the system every year. Said another way, the rental method assigns costs that have already been incurred to every customer, every year. Including sunk costs in a marginal cost analysis is inappropriate and results in an over-estimate of marginal customer costs.

Q. What are replacement costs in context of the rental method?

A. Replacement costs are incurred when an asset requires replacement before its estimated service life ends.

Q. How does PSNH account for replacement costs in its marginal customer cost calculation?

A. PSNH makes an adjustment to the economic carrying charge in order to increase the annual rental fee charged to all customers.[122]

Q. Why is it inappropriate to include replacement costs in marginal customer costs?

A. Replacement costs are not growth related. Adding an additional customer to the system does not directly increase replacement costs for the utility. For this reason, PSNH's adjustment to the economic carrying charge is inappropriate.

[122] *See* PSNH response to OCA Data Request OCA 2-051, specifically CONFIDENTIAL Attachment OCA 2-051A (REVISED), tab W29).

Q. How does the rental method disregard depreciation?

A. The rental method collects annual charges that are equal to the revenue requirement associated with installing a meter and services from every customer on the system. The annual rental charge is then inflated over the life of the investment.[123] Because of the method used to inflate meter and service costs, the annual charges represent the cost of using these assets as though they were brand new every year they are owned. This is not true and would not occur in a competitive market. The cost of assets in competitive markets are partially determined by the age of the good. This is because as assets age, the technology of newer similar assets improves, and the older assets' functionality deteriorates. Take a computer, for example. A consumer obviously would not pay the same amount for a five-year-old computer as she would for a new computer. But the rental method assumes that she would. Computers may seem like an extreme example, but advanced metering technology has many parallels. A customer similarly would not pay the same price for a new meter that she would for a 30-year-old meter. However, PSNH's methodology assumes that she would.

Q. What are your empirical critiques of PSNH's minimum cost calculation?

A. PSNH includes costs that are not marginal or not reasonable in its calculation of marginal customer costs.

[123] *See* PSNH response to OCA Data Request OCA 2-051, specifically CONFIDENTIAL Attachment OCA 2-051A (REVISED).

Q. Did PSNH initially include non-marginal costs within its calculation of marginal customer costs?

A. Yes. PSNH included approximately $20 million of energy efficiency ("EE") administration costs in its estimate of marginal customer costs. In OCA 7-012, I asked if the Company was including any such costs in FERC Account 908 and for justification if so. The Company responded that the filed MCOSS indeed included these costs, but that the Company had removed them "upon confirming that these expenses are recovered entirely outside the Company's distribution rates."[124]

Q. What was the impact of including these EE administration costs?

A. ****BEGIN CONFIDENTIAL**** [redacted] ****END CONFIDENTIAL****

Q. Should Witness Nieto have included these EE administration costs in the MCOSS to begin with?

A. No. EE administration costs are not caused by the number of customers. Rather, EE administration costs are caused by energy sales, as they represent an effort to

---

[124] *See* Schedule REN-10.

[125] *See* PSNH response to OCA Data Request OCA 2-051, specifically CONFIDENTIAL Attachment OCA 2-051A (REVISED) and CONFIDENTIAL Attachment OCA 2-051A.

decrease energy sales though energy efficiency investments. These costs should not be included in an MCOSS.

Q. Has Witness Nieto encountered this issue before?

A. Yes. Witness Nieto included and then removed the very same costs in a recent Minnesota rate case. The impact in that case was an increase of approximately 25 percent in estimated residential marginal customer costs.[126] In that case, Witness Nieto had originally provided a workpaper that said EE administration costs were nonmarginal; but in the final model that assumption was changed to include EE administration costs as marginal customer costs.[127] After multiple rounds of testimony, Witness Nieto ultimately filed a letter acknowledging that "a better approach"[128] would be to exclude them, and updated the marginal customer cost calculation accordingly.

It is surprising that despite this experience in Minnesota, EE administration costs were again included as marginal customer costs in PSNH's model, again identified by intervenors, and again removed by Witness Nieto. Given this is not the first time it has happened, it is hard to imagine that their inclusion in this case was a mistake.

Q. Please explain how PSNH weighs customer account costs.

---

[126] *See* Surrebuttal of Ron Nelson in MPUC Docket No. E-017/GR-15-1033, filed September 28, 2016. At 18-19.
[127] See Surrebuttal of Ron Nelson in MPUC Docket No. E-017/GR-15-1033, filed September 28, 2016. At 18-19.
[128] *See* Summary of Testimony of Amparo Nieto in MPUC Docket No. E-017/GR-15-1033 (October 11, 2016) at 2.

A. PSNH divides annual customer account expenses and customer service and informational expenses for 2014-2018 by weighted number of accounts to obtain a cost of each expense per weighted customer.[129] As previously mentioned, the original rate case Estimated Annual Weighted Customer Service and Information Expense decreased from PSNH's previously-filed MCOSS by 99 percent, falling from $19.99 to $0.16. The revised MCOSS, filed after the Company removed the energy efficiency administration costs I identified, reports that number as [redacted], which is a similarly enormous reduction from the previous MCOSS.[130] PSNH did not provide sufficient justification for the drastic change in weighted average number of customers that caused this significantly different result.

Q. Are there other methods besides the rental method that can be used to inform customer charges?

A. Yes. There are a few different ways to calculate customer charges, against which these marginal customer cost calculations could be compared. The basic customer approach, from the ACOSS, should be seen as the ceiling for customer charges. The customer specific approach is again derived from an allocated cost study, but draws upon fewer FERC accounts than in the basic customer approach. The customer specific approach recognizes that some of the customer-specific FERC accounts are not marginal and should not be collected through a customer charge. Finally, the new customer only

---

[129] *See* PSNH response to OCA Data Request OCA 2-051, specifically CONFIDENTIAL Attachment OCA 2-051A (REVISED), tab W19).
[130] *Id.*

method is a marginal cost approach that uses the same capital investment cost per customer for meters and services as does the rental method, but only assumes that cost for the number of new customers added to the system in a given year. The new customer only method then spreads these costs across the class.

Q. Is the Company's marginal customer cost reasonable, in comparison to other potential calculation methods?

A. PSNH's MCOSS proposes a residential marginal customer cost of $14.91, which is not far off from the basic customer ACOSS ($13.82). However, given PSNH's additional $16.96 "local distribution facilities cost,"[131] which will be discussed below, the fixed portion of a residential customer bill ends up exceeding $30, which is an unreasonable amount. While the basic customer ACOSS relies on embedded costs, I find it to be a more consistent and less manipulatable cost estimate than marginal cost estimates. For that reason, I recommend using the basic customer costs as a ceiling for the residential customer charge in this case.

3. The Concept of Design Demand

Q. What is design demand?

A. Witness Nieto defines design demand as kW of customer maximum connected demand.[132]

[131] *See* Ms. Nieto's Testimony, Bates 001757.
[132] *See* Ms. Nieto's Testimony, Bates 001732, lines 11-12.

Q. How does Witness Nieto explain the concept of design demand?

A. Witness Nieto introduces a monthly distribution facility charge based on an estimate of the average installed cost of distribution facilities in a rate class; this cost is evidently a result of the individual customers' design demand that the Company considers when installing a transformer and local lines.[133]

Q. Do you have concerns with the local distribution facility charge and the concept of design demand?

A. Yes. I have three primary concerns with design demand. First, it is not a recognized distribution design criterion. Second, it does not align as well with cost causation when compared to other marginal cost estimation approaches. Finally, the concept of design demand focuses on a static (i.e., short-term) state of the distribution system; incorporating a cost measure that reflects dynamic (long-term) changes may be more efficient. I will elaborate on each of these concerns below.

Q. Is design demand a recognized distribution design concept?

A. No. The concept of design demand is unique to Witness Nieto's testimony. There is neither industry literature nor internal PSNH documentation that utilizes this concept. Witness Nieto claimed that PSNH designs certain distribution facilities by "using engineering standards that take into consideration the number of customers who

[133] *See* Ms. Nieto's Testimony, Bates 001743, line 15.

will use those facilities, and those customers' expected maximum loads"[134] and yet she does not cite a single planning document to substantiate this assertion.

When asked in discovery to provide industry literature supporting the concept, Witness Nieto cited only her own work.[135] When asked to provide Company documents that explicitly relate to design demand, Witness Nieto could not provide evidence that the Company uses it to plan the system.[136]

It cannot be overstated how important it is that the Company does not use design demand to plan its system. Planning criteria and processes are used to inform cost causation all over the country. Without a connection to the utility's planning, the cost causation of Witness Nieto's design demand concept is tenuous at best.

Q. Are there other reasons that design demand does not reflect cost causation?

A. Yes. The concept of design demand is static. To estimate design demand, Witness Nieto divides the cost of local facilities, by the average number of customers. It assumes that a transformer, for example, serves a fixed average number of customers, based on a rate class' average maximum connected demand. The cost of the transformer is then divided among the estimated number of customers sharing the facility. The problem with that assumption is that the expected maximum kW of demand per customer can change over time. Changes in expected maximum demand would in turn

[134] *See* Attachment MCOSS-1 (Perm), Bates 001773.
[135] *See* Schedule REN-11.
[136] *See* Schedule REN-12.

change the number of customers who can share the transformer and the cost burden that each of them should be responsible for.

Basing design demand on connected load creates a problem when using the estimate to inform rates. The problem is that as connected loads change, because of EVs or energy efficiency, the average number of customers per facility changes, but the charge does not change. This differs from a non-coincident or coincident peak charge that is traditionally used to collect demand related costs for some customer classes. When using a non-coincident peak demand charge, the price paid for facilities changes with the customers load. This result is not only inequitable but sending an inefficient price signal to the customer.

Q. Do you have an example of when the assumption of fixed customer demand would not hold true?

A. Yes. Say, for example, that customers begin to invest in electric vehicles. Their demand will increase substantially, and potentially at peak times when they find it convenient to charge. Because Witness Nieto's design demand concept is a fixed bill charge, it sends those customers a price signal that the customer has no control over that part of the bill, and therefore no incentive to charge at off-peak times. All else constant, this approach will lead to more transformers being overloaded.

Witness Nieto's justification for the fixed price signal suggests that fluctuating customer demand cannot impact the transformer: "this approach recognizes the more

121

fixed nature of the transformers, which are sized based on the maximum demands that the local customers can be expected to impose over the service life of the facilities."[137] However, when multiple customers buy EVs, they certainly will impact their transformers and force a resizing. The consequences will be costly if PSNH cannot send signals to customers about when to charge; the fixed bill charge will become insufficient and the Company will likely under-collect revenue.

Q. Do you have another example?

A. In a different scenario, demand response could drastically change the ability to shape customer load, which would raise the number of residents sharing a single transformer. If that transformer can serve more people in a few years, and yet charged them $16.96 a month, this becomes a highly inequitable and inefficient mechanism for collecting costs.

Q. Has the assumption of fixed customer demand been disproven in practice?

A. Yes. In the concurrent rate case proceeding of Liberty Utilities, Liberty discussed needing to upgrade numerous transformers due to capacity issues[138] – an indication that local demand can change and trigger transformer upgrades.

Q. What else concerns you about the Company's design demand concept?

---

[137] *See* Ms. Nieto's Testimony, Bates 001732, lines 14-16.
[138] *See* Schedule REN-13.

A. Not only are there fundamental flaws to basing fixed monthly charges on the concept of design demand, but the concept and its justification are also inconsistent and unreasonable themselves.

Q. Does the Company include unreasonable equipment in its local distribution facilities costs?

A. Yes. Witness Nieto includes primary distribution equipment in local facilities costs. However, primary lines should not be sized or upgraded for an individual new customer. It seems inappropriate to include primary distribution costs in local facilities charge when they are installed at much higher voltages.

Q. Does PSNH discovery contradict the idea of distribution planning that centers on design demand?

A. Yes. The Company uses standard transformers, which contradicts the idea of planning around different customers' demands. PSNH states that "for residential customers the Company uses transformers of standardized sizes … intended to be sufficient to meet the expected long-term maximum load of the customer(s) that will be served from those facilities."[139] The fact that the Company uses standardized transformers opposes the design demand argument. I note that the standard is not stated to be based on the numbers of customers, and likely is not, because the number of customers connected to one standardized transformer varies.

[139] *See* Schedule REN-12.

Q. Does Witness Nieto accurately represent the other utilities that use a monthly distribution facilities charge?

A. No. When asked to provide examples of other jurisdictions that base their monthly distribution facilities charge on local distribution facilities rather than on customer demand, Witness Nieto misrepresents Otter Tail Power company as doing so.[140] To the contrary, the MN Commission's 2017 Order stated: "the Commission will direct Otter Tail to abolish its fixed facility charge for [the residential] class, and to recover the additional cost of the relevant facilities via volumetric rates instead."[141] The Minnesota PUC rightly found volumetric rate recovery to be more efficient that the facilities charge estimate by Witness Nieto in that case.

Q. What do you conclude about the Company's proposed design demand concept and resulting monthly facilities charge?

A. I conclude that the design demand concept is too short-sighted to represent distribution cost causation reliably, especially due to its flawed assumption about the static nature of customer demand and its exclusive use by Witness Nieto rather than the broad electric industry or even PSNH planners.

---

[140] *See* Schedule REN-14.
[141] Order in Docket No. E-017/GR-15-1033 (May 1, 2017) at 76.

D. Utilizing Cost Study Results in Practice

Q. Have commissions in other states noted broad concerns with utility conducted cost studies?

A. Yes. Commissions in Massachusetts, Minnesota, and New York have found that using multiple cost studies is appropriate.

Q. Does the Massachusetts DPU heavily weigh the results of its utilities' MCOSSes?

A. No. Per National Grid's 2018 rate case proceeding, "as a practical matter, the Department does not rely on a marginal cost study in designing rates for electric and gas distribution companies."[142] As a result, the DPU neither accepted nor rejected the Company's marginal cost study "as the study has no relationship to the rates established in this Order, nor is it used for any other purpose related to this base distribution rate case."[143] In fact, the Department has abandoned the use and consideration of marginal cost studies in some instances, "find[ing] no compelling reason to continue to require National Grid to file a marginal cost study as part of future electric base distribution rate cases."[144]

Q. What did the Minnesota PUC approve regarding multiple cost studies?

[142] Order in D.P.U. 18-150 at 516.
[143] Order in D.P.U. 18-150 at 517.
[144] Order in D.P.U. 18-150 at 517.

A. In the 2015 rate case proceeding of Xcel Energy, the Commission's Findings of Fact, Conclusions, and Order stressed that cost models are imperfect due to their inherent simplification of a utility's system. In the proceeding, the parties disputed at least five different ways of classifying the cost of distribution plant. Ultimately, the Commission decided it would be necessary to continue to "consider a range of classification methods for purposes of allocating responsibility for the necessary revenues"[145] because no cost-study methodology can be superior to all others in every context.

Q. What did the New York PSC approve regarding multiple MCOSS approaches?

A. In the 2015 rate case proceedings of New York State Electric & Gas (NYSEG) and Rochester Gas & Electric (RG&E), the Commission's Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal approved a Joint Proposal that prescribed that "the Companies will initiate discussions with Staff and any interested parties to review and identify up to three specific methodologies for conducting future electric marginal cost studies…The Companies agree to perform and file in their next rate cases up to three marginal cost of service studies, one for each identified methodology."[146]

Q. Please summarize the issues you have addressed in your MCOSS analysis.

[145] Order – Finding of Fact, Conclusions, and Order In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota (Docket 15-826) at 45.
[146] Joint Proposal in Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service. Cases 15-E-0283, 15-G-0284, 15-E-0285, 15-G-0286. Appendix W, p. 1.

A. I have discussed the fact that PSNH subjectively changed several of its MCOSS assumptions and inputs, which dramatically altered its results in a very short period of time; that PSNH's marginal customer cost calculations are flawed in several ways; and that PSNH uses a planning concept, so-called design demand, that is not an industry standard or reflective of the Company's system planning, to argue for a higher portion of fixed costs on customer bills.

Q. What are your recommendations based on your review of the Marginal Cost of Service Studies?

A. For this case, I recommend that the Commission not rely on PSNH's MCOSS for revenue apportionment or rate design decisions.

In future rate cases, if the Commission chooses to rely on cost studies guided directly by the Company, I recommend these cost of service studies be relied upon as directional indicators as opposed to point estimates. The Commission should weigh policy factors heavily when apportioning revenue and designing rates.

If the Commission wishes to rely more heavily on MCOSS, I recommend that more transparency be required. Improved transparency could be accomplished through a stakeholder process or a process that uses independent contractors that are directed by Staff or the OCA. Lastly, I recommend that the Commission incorporate lessons learned from its locational value of DER project into utility MCOSS.

127

VII. REVENUE APPORTIONMENT

Q. What revenue apportionment did the Company propose?

A. The Company's proposed revenue apportionment is below.

Table 2. Summary of Proposed Rate Changes ($000)[147]

Rate Class	Current Revenue	Proposed Revenue	Change	Percent Change
Residential Rate R	$659,913	$708,241	$48,328	7.3%
General Service Rate G	322,934	336,804	13,870	4.3%
Primary General Service Rate GV	297,686	303,776	6,090	2.0%
Large General Service Rate LG	203,600	207,263	3,663	1.8%
Outdoor Lighting (OL/EOL)	11,456	9,420	(2,036)	-17.8%
Total	$1,495,589	$1,565,504	$69,915	4.7%

Q. What approach did the Company use to determine its revenue apportionment?

A. The Company utilized Witness Nieto's ACOSS to allocate revenue requirements to each rate class, by comparing the earned return to the required rates of return for each rate class and developing allocations that would bring these closer together without unacceptable bill impacts.[148]

Q. Do you find the Company's proposed class revenue targets to be reasonable?

[147] *See* Mr. Davis' Testimony, Bates 001806.
[148] *See* Mr. Davis' Testimony, Bates 001804.

A. No. I do not agree with the Company's proposed class revenue targets because they were informed by the Company's costs studies.

Q. What factors did you consider when creating your alternative?

A. I considered the basic customer and minimum system ACOSSes, while qualitatively weighting the basic customer ACOSS more heavily.

Table 3: Required Change in Rates per the ACOSS, under Different Approaches[149],[150]

****BEGIN CONFIDENTIAL****

	Total Retail	R PL+TOD	R LCS	RWH	GPL+TOD	G SH	G LCS	G-WH	GV	LG	RATE B	OL	EOL
Minimum System Approach													
Basic Customer Approach													

****END CONFIDENTIAL****

As Table 3 demonstrates, the assumption associated with classifying distribution equipment is a key factor in determining whether a class is should be given a rate increase above or below the average increase.

Q. How do you recommend the Commission set class revenue targets in this case?

A. I recommend the revenue apportionment from the table below.

[149] *See* PSNH Response to OCA Data Request OCA 2-052, CONFIDENTIAL Attachment OCA 2-052 A.
[150] *See* PSNH Response to OCA Data Request OCA, CONFIDENTIAL Attachment OCA 8-043.

129

Table 4: Revenue Apportionment

	Estimated Annual Revenue		Proposed Annual Change	
Class of Service	Current Rates	Proposed Rates	Revenue	Percent
Residential Service Rate R and R-OTOD	$ 659,913,174	$ 690,731,119	$ 30,817,945	4.67%
General Service Rate G and Rate G-OTOD	$ 322,934,391	$ 338,112,307	$ 15,177,916	4.70%
		$ -		
Primary General Service Rate GV	$ 297,685,774	$ 311,662,121	$ 13,976,347	4.70%
		$ -		
Large General Service Rate LG	$ 203,600,141	$ 213,271,148	$ 9,671,007	4.75%
		$ -		
Outdoor Lighting Service Rate OL and Rate EOL	$ 11,455,860	$ 11,725,073	$ 269,213	2.35%
Total	$ 1,495,589,340	$ 1,565,504,000	$ 69,912,428	4.67%

My revenue apportionment clusters rate increases more closely around the average system increase. I also do not recommend giving the outdoor lighting class a rate decrease. When there is a system wide increase or decrease in rates, the burden or benefit should be shared by all classes.

VIII. RESIDENTIAL RATE DESIGN

Q. How is this section of your testimony organized?

A. I address the Company's proposed residential rate design changes and make alternative recommendations.

Q. When evaluating the Company's proposed rate design proposals, did you consider any New Hampshire or Commission specific materials?

130

A. Yes. I considered the rate design principles set out in the Staff Recommendation on Grid Modernization and the principles reflected in the EERS.[151] I also considered the federal Energy Policy Act of 2005 ("EPACT 2005") and the Commission's implementation order.[152]

Q. What changes has the Company proposed for residential rate design?

A. PSNH is proposing to raise the residential customer charges from $12.69 to $13.89 per month.[153]

Q. What support did the Company provide for its increases in the residential customer charge?

A. The Company informed the magnitude of the rate design components (i.e., demand and customer charges) on its MCOSS and ACOSS.[154] The Company primarily focused on increasing fixed charges, including demand charges, so that it can insulate itself from revenue risk.[155] The Company did not recommend structural changes, such as the narrower TOU period for large customers recommended by Witness Nieto, because the Company wanted to ensure "customer understanding and acceptability."[156]

---

[151] "Staff Recommendation on Grid Modernization" (Feb 12, 2019) in IR 15-296 at 49.
[152] *See* Order No. 24,893 (Sept. 15, 2008) in Docket DE 06-061 (noting that the standards recommended for state adoption in EPACT 2005 concerned net metering, fuel diversity, fossil fuel generation efficiency, time-of-use pricing, advanced metering infrastructure, and interconnection).
[153] *See* Attachment EAD-6, Bates 002051.
[154] *See* Witness Davis's Testimony, Bates 001804.
[155] *See* Witness Davis's Testimony, Bates 001807, lines 12-13, stating "In most rate classes, a move toward more efficient pricing has been made setting the proposed customer charge."
[156] *See* Witness Davis's Testimony, Bates 001807, lines 1-2.

Q. Please provide a general response to the Company's approach to rate design.

A. The Company's approach to rate design goes against state policy. The Company is focusing primarily on increasing fixed charges, when state policy indicates that volumetric rate recovery should be prioritized while utilizing TOU rates.

Q. What do you recommend for the residential customer charges?

A. I recommend that the customer charge be lowered to $11 for the residential customer class.

Q. What quantitative information did you rely on to inform the residential customer charge?

A. I considered the cost classified as customer-related within the basic customer ACOSS and an alternative ACOSS that removed the costs of service lines from customer costs. These two customer cost estimates gave me a range of $9.86 to $13.82.

I consider the customer costs from the basic customer approach as the ceiling for a customer charge. The basic customer ACOSS includes embedded metering and service line costs, along with O&M, depreciation, and customer account expenses. Altering the ACOSS to remove the costs associated with service lines gives a lower bound for a customer charge. Removing service line costs acknowledges that not all residential customers have a dedicated service line (e.g., multi-family houses). While, theoretically, marginal costs are more economically efficient, I find that this estimate for customer costs is consistent and is an objective estimate of costs that should be included in a customer charge.

Q. Please explain why you are recommending a decrease in the residential customer charges.

A. I am recommending a decrease in the residential customer charge for a few reasons. First, I do not find it reasonable to use the Company's MCOSS and ACOSS to inform rate designs. Second, keeping customer charges low better aligns with state policy goals.

Q. Why is it unreasonable to rely on the Company ACOSS and MCOSS to inform rate design?

A. It is unreasonable to rely on the MCOSS to inform rate design because the Company made numerous changes to the underlying assumptions that drastically altered the results with insufficient explanation for doing so.

As for the ACOSS, I demonstrated that the number of customer costs classified within the model are drastically inflated with minimum system approach. However, I utilize some information from the ACOSS to inform my residential rate design recommendation because I find it more straight-forward and less open to manipulation.

The Company is claiming that over $30 should be collected through the residential charge - marginal customer costs plus the local facilities charge. This is slightly under the embedded customer costs of approximately $33 per customer the

Company calculated using the minimum system approach. Neither of the approaches utilized by the Company is reasonable. In fact, both are laughably large fixed charges that go against state policy goals. The estimates for customer charge are summarized below.

Minimum System Customer Costs	Marginal Customer Cost	Local Facilities Charge	Basic Customer
$33.41	$14.91	$16.96	$9.86 - 13.82

Q. What state policy goals will be more effectively achieved through a lower customer charge?

A. Lowering the customer charge and increasing the volumetric rate, will aid the state in achieving its EERS by strengthening customers incentive to invest in energy efficiency.

IX. RECOMMENDATIONS AND CONCLUSION

Q. What are your specific conclusions and recommendations for the Commission?

A. My conclusions and recommendations are as follows:

1. Step year adjustments beyond 2019 should not be approved until further ratepayer protections have been incorporated into the regulatory framework.
2. The LRAM should be replaced with a symmetrical revenue decoupling mechanism.
3. Effective implementation of symmetrical revenue decoupling should include:

   a. a timeline for analyzing and, when cost-effective, implementing Conservation Voltage Reduction;
   b. a timeline for updating DER interconnection standards; and
   c. more specific advanced rate designs.
4. The symmetric revenue decoupling mechanism should have the technical design characteristics that I describe in Section IV.B.4.
5. The Commission should rely on the basic customer ACOSS, not the minimum system ACOSS.
6. The Commission should continue to require the Company to file an ACOSS.
7. The Commission should not inform revenue apportionment or rate design on the Company's MCOSS.
8. For residential classes, the customer charge should be lower to $11.

Q. Does this conclude your direct testimony?

A. Yes.