STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

<u>In the matter of</u>

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

Docket No. DE 19-064

Petition for Permanent Rate Increase

DIRECT TESTIMONY

OF

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Senior Manager
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On Behalf of the Office of the Consumer Advocate

December 6, 2019

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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 embedded and marginal 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 Schedule REN-1.

Q. Do you have other relevant experience related to evaluating Liberty'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 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. No.

II. PURPOSE AND RECOMMENDATIONS

Q. What is the purpose of your testimony?

A. I am testifying on issues regarding the regulatory framework changes that Liberty Utilities Corporation ("Liberty" or "the Company") has proposed including decoupling and step year adjustments. I am also testifying on the Marginal Cost of Service Study ("MCOSS"), revenue apportionment, and rate design.

Q. How is your testimony organized?

A. My testimony is organized into five additional sections and a conclusion: Section III discusses the implication of the Company's proposed regulatory framework changes; Section IV analyzes the technical aspects of Liberty's decoupling proposal; Section V describes and analyzes the MCOSS; Section VI provides my recommendations for revenue apportionment; Section VII provides my analysis and recommendations related to residential rate design and Rate D-EV; and, finally, Section VIII 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 Liberty's proposal to have step year adjustments beyond 2019.

Q. What are your recommendations regarding the Company's revenue decoupling proposal?

A. I have recommendations related to the effective implementation of decoupling and the technical mechanics of the proposed mechanism.

Regarding the implementation of decoupling, I recommend that several reasonable commitments be made by the Company to complement the 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.

Regarding the technical mechanics of the decoupling mechanism, I recommend that the Commission modify the mechanism is three ways. First, the decoupling mechanism should administer refunds and surcharges using a total revenues allocator, not an energy allocator. Second, an annual soft cap of 3 percent should be applied to surcharges and refunds. Third, for rate classes with time-of-use ("TOU") rates decoupling surcharges should be applied to the on-peak period and credits should be applied to the off-peak period.

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

A. I provide a few recommendations for the Commission to consider. I begin with my primary recommendation, but also discuss some alternatives that the Commission may also wish to consider.

To better inform revenue apportionment and rate design, I recommend that the Commission consider multiple cost studies. Relying on multiple studies will provide the Commission with a range of results that can be used to inform revenue apportionment and rate design. Specifically, I suggest that the Company be required to file both marginal and embedded cost studies in its next rate case. As for the MCOS, I recommend that the Company be required to use a planning approach to estimate marginal costs. The regression and averaging approaches that have been utilized previously by the Company add vary little, if any, valuable information to the revenue apportionment and rate design process.

In future rate cases, if the Commission is relying 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 design rates.

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

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

A. I recommend that the Commission equally apportion rate increases across customer classes.

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

A. For the residential classes, I recommend that the Commission reduce the customer charge to $10.

For the proposed Rate D-EV, I recommend the fixed charge be reduced to $6.52.

III. ALTERNATIVE REGULATION: MYRP AND DECOUPLING

Q. How is this section of your testimony organized?

A. In the remainder of this section, I provide initial reactions to Liberty's proposed changes related to step year adjustments and decoupling. In Section III.A, I discuss the implications of Liberty's proposal to alter the regulatory structure with multiple step year adjustments. In Section III.B, I discuss how to implement decoupling to ensure that benefits accrue to ratepayers. Finally, in Section III.C, I make recommendations to more effectively implement decoupling.

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. I also discuss decoupling, how it alters the regulatory framework, its shortcomings, and how to implement it effectively.

At the end of the section, I make recommendations for more effective implementation of decoupling and explain why it is necessary to reject rate changes beyond the 2019 step year adjustment.

Q. What are your general impressions of Liberty's step year adjustment and decoupling proposals?

A. Liberty's proposal to have step year adjustments beyond 2019 is a significant regulatory change. Approving step years beyond 2019 would create a regulatory framework based on an MYRP because rates would continue to increase outside of a rate case. Regulatory frameworks with MYRP are synonymous with a PBR framework in many jurisdictions. This is important because PBR frameworks often include additional regulatory mechanisms to ensure that ratepayers benefit from altering the traditional regulatory framework that has endured for numerous decades in most states. Liberty's MYRP proposal does not include PBR-related mechanisms. Without thoughtful implementation, a MYRP will provide benefits only to the Company and its shareholders.

Decoupling is also a significant regulatory change. However, decoupling is a much less complicated structural change than an MYRP. While Liberty's decoupling proposal is generally reasonable, I recommend changes related to its implementation and its technical design.

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.[1] Many of the processes in other states are multi-year efforts with the objective of comprehensively designing a MYRP

[1] E.g., Maryland, Hawai'i, and Minnesota all have proceeding open to examine aspects of a MYRP.

framework with complementary PBR mechanisms. State regulators are investing significant resources to ensure that MYRPs are designed properly.

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. Are you aware that MYRPs have previously been approved by the Commission?

A. Yes. I am aware that the Commission has approved MYRPs previously. It does not appear that the Commission has considered all relevant arguments against implementing MYRPs that are not appropriately complemented by PBR mechanisms and planning processes. Additionally, other commissions have initially approved MYRPs and then opened proceedings to reevaluate their structure and purpose.[2]

In Minnesota and Hawai'i, MYRPs were reevaluated because regulators were not satisfied with utility performance.[3] These reevaluations have been focused on getting the regulated utilities to commit to achieving state policy goals and measuring their performance. In exchange, utilities in these states will receive improved revenue recovery options and potentially additional financial incentives.

[2] 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.
[3] *See* Hawai'i PUC Docket No. 2018-0088 and MN PUC Docket No. 17-401.

A. MYRPs Require Comprehensive Implementation to Create Benefits for Ratepayers

Q. Please summarize Liberty's proposed step-year adjustments.

A. In the testimony of Witnesses Greene and Simek, the Company proposes a 2019 step increase to recover an approximate annual revenue deficiency of $2.3 million.[4] The purpose of the 2019 step increase is to collect the "significant capital investments" made during this proceeding.[5]

Additionally, in the testimony of Witnesses Rivera, Strabone, and Tebbetts, the Company has proposed to recover step adjustments beyond 2019. However, the Company did not specify for how many years it desires to increase rates beyond 2019.[6] The proposed step adjustments would increase rates to recover 80 percent of the non-Reliability Enhancement Project ("REP") changes in net plant.[7]

Q. Do you have concerns with the Company's proposed step year adjustments?

A. Yes. While I find the 2019 step year adjustment to be similar to the future test year approach used by numerous states, the proposal for step years beyond 2019 concerns me greatly. The Company's proposal to change rates beyond 2019 creates regulatory structure based on an MYRP. Changing to a MYRP regulatory structure is a

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[4] *See* Mr. Green and Mr. Simek's Testimony, Bates II-093.
[5] *See* Mr. Green and Mr. Simek's Testimony, Bates II-093, lines 19-20.
[6] See Mr. Rivera, Mr. Strabone, and Ms. Tebbetts' Testimony, Bates II-190.
[7] See Mr. Rivera, Mr. Strabone, and Ms. Tebbetts' Testimony, Bates II-190.

major divergence from traditional regulation and should be implemented in conjunction with additional PBR mechanism.[8]

The Company did not provide the detail or propose sufficient ratepayer protections (i.e. PBR mechanisms) to adopt such a significant change to the regulatory structure. The purpose of this section of my testimony is to demonstrate that without additional process and performance measures a MYRP will not generate benefits for ratepayers equal to or greater than those generated for shareholders and the utility. For that reason, the MYRP proposed by Liberty should be rejected.

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.

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[8] It is also important to ensure that proper planning processes, such as integrated distribution planning, is established before a MYRP is approved.

MYRPs are synonymous with PBR in many jurisdictions and in some industry literature.[9] Using the terminology of step-year adjustments avoids acknowledging what numerous regulators have recognized – that allowing a utility to adjust rates outside of a test-year rate case is a significant regulatory change. Given the significance of this change, additional regulatory scrutiny is required in the form of, at a minimum, performance measurement and, at a maximum, a comprehensive review of the state's regulatory framework as it is applied to the subject utility. The additional regulatory oversight is needed to ensure that ratepayers receive tangible benefits in exchange for the certainty provided to the utility through the MYRP.

Q. What does the Company claim is the purpose of the MYRP?

A. The Company mentions at least three reasons for proposing the MYRP. First, the MYRP will reduce regulatory lag. Second, the Company claims that it will reduce the frequency, and therefore expense, of rate cases. Lastly, the Company claims that it will allow the utility to devote "more time and attention to exploring and planning for the future of the electric industry (in the grid modernization docket)."[10]

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

[9] Melissa Whited, Tim Woolf, and Alice Napoleon, "Utility Performance Incentive Mechanisms: A Handbook for Regulators," Synapse Energy Economics (Prepared for the Western Interstate Energy Board, March 2015).
[10] *See* Mr. Mullen's Testimony, Bates II-207, lines 9-10.

A. No. The Company's proposed MYRP 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 an important, holistic review of the utilities finances and an opportunity to make tariff changes. While the Company claims that a reduction in the number of rate cases will allow it to "explore and plan for the grid of the future," a rate case will be required to make tariff changes that create the grid of the future (e.g., advances in rate design). The Company has failed to identify tangible and clear benefits to ratepayers associated with the proposed MYRP.

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; and (4) utilities over-earning due to a lack of protective regulatory mechanisms. Simply stated, MYRPs can 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. 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 have multiple states committed to multi-year proceedings focused on effective implementation of MYRPs and PBR?

A. The objective that regulators are attempting to achieve through the combination of MYRPs, complementary PBR mechanisms, and transparent planning processes is to align utility incentives comprehensively with the interests of ratepayers. An MYRP, by itself, does not achieve this objective. In fact, a MYRP without complementary PBR mechanisms is nothing but a revenue collection device—failing dramatically at aligning utility incentives and ratepayer benefits. For this reason, regulators must comprehensively design the MYRP and complementary PBR mechanisms to ensure a cohesive PBR framework that provide benefits for ratepayers.

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

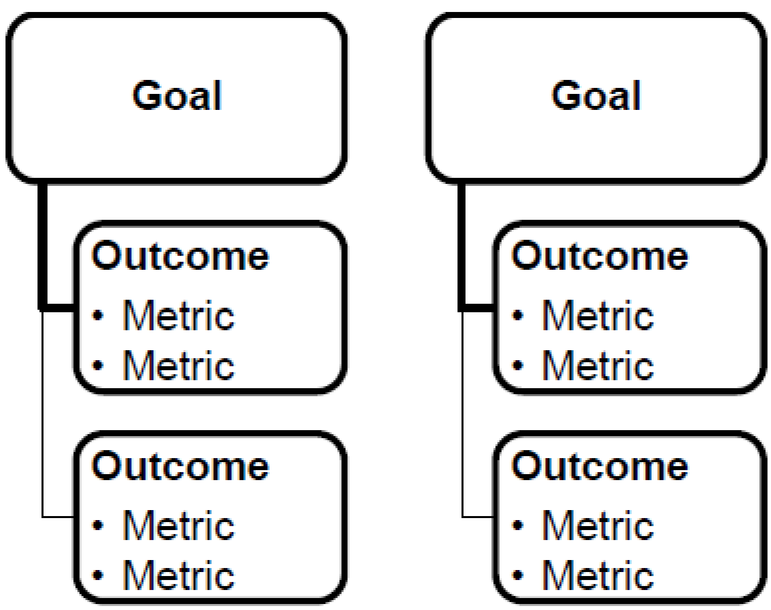
A. While the utilization and structural design of components within a PBR framework vary widely by state and country, the MYRP is often complemented by numerous PBR mechanisms, such as efficiency carry-over mechanisms, consumer dividends, and various forms of performance tracking.[11] Many of the PBR mechanisms that complement an MYRP are designed to protect consumers by better aligning the economic incentives within the PBR framework with those of ratepayers.

[11] 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 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.

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

A. Performance mechanisms are an example of an important PBR mechanism that can be used to protect consumers when moving into an PBR regime. When designing a PBR framework, multiples 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.[12] The organization is visualized in Figure 1, below.

Figure 1



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

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.[13]

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 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 mechanisms 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

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

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 Liberty propose additional PBR related components to ensure ratepayers would receive benefits, while the Company benefits through improved revenue recovery?

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

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 a 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 implement decoupling in a way that focuses more on performance and achieving state policy goals.

B. Decoupling: Ensuring Benefits are Realized by Ratepayers

Q. What is revenue decoupling?

A. Revenue 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 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.

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

A. In practice, it is difficult to say precisely how decoupling impacts the economic incentives of an electric utility. Theoretically, in the short-term, decoupling removes the utility's disincentive to encourage and administer energy efficiency, DERs or other technologies that reduce the utility's kWh sales. Thus, 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. 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 decoupling does 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 investments to grow rate base and thereby to increase revenues.[14] Increasing demand requirements (i.e., sales) is one way to justify more infrastructure spending. This suggests that decoupling's ability to "disincentivize" utilities impeding progress related to energy efficiency, DERs and other technologies is not as complete as some advocates suggest. 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. The limitations of decoupling are important to recognize and understand because they can be avoided, for the most part, with improved implementation.

Q. By itself, does decoupling a utility's revenues guarantee achievement of any state policy goals?

A. No. Decoupling only removes one utility disincentive against certain state policy goals, such as energy efficiency. There is no assurance that policy goals will be met.

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

Decoupling on its own does not provide an incentive for utilities to offer additional energy efficiency services.

Q. Has the Commission addressed revenue decoupling in any recent dockets?

A. Yes. The Commission has addressed revenue 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 from a Lost Revenue Adjustment Mechanism (LRAM) to decoupling or "another mechanism."[15] The EERS Settlement also increased the energy savings goals for both electric and natural gas utilities.

Q. What are some important differences between an LRAM and 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.[16] In theory, the LRAM removes the disincentive that the utility has to implement said energy efficiency program. However, decoupling is more comprehensive approach to changing the utility's incentives. By compensating the utility through means other kWh sales (e.g., a revenue

[15] Energy Efficiency Resource Standard Settlement Agreement. Filed April 27, 2016 in Docket DE 15-137 at 6.
[16] LRAMs incentives often consist of complicated savings calculations that can result in stakeholder disputes, resulting in additional resources to implement.

per customer approach), decoupling removes disincentives beyond those affected by the LRAM. For example, 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.

Additionally, decoupling is symmetric. Not only does 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 decoupling makes the mechanism more equitable for ratepayers.

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

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

Q. Please explain the relevant information from the EnergyNorth natural gas rate case.

A. The EnergyNorth rate case was the first case in which the Commission approved a decoupling mechanism. At the same time the Commission adopted the decoupling mechanism, it acknowledged the influence that decoupling should have on a utility's rate design by decreasing the residential customer charge. In the EnergyNorth rate case, the OCA testified that decoupling "achieves a broader, more fundamental shift in (utility) incentives" and recommended that the residential customer charge be decreased.[17] The Commission's EnergyNorth Order demonstrates that the achievement of policy goals and adoption of decoupling should be explicitly linked. Furthermore, the Commission's Order acknowledges that the impact of decoupling should extend beyond energy efficiency, into rate design structures.[18]

Q. What are the important takeaways from the EERS and EnergyNorth proceedings?

A. In both proceedings, the Commission sought balance by providing utilities with a financial incentive for successful implementation of preferred state policies, while at the same time requiring them to commit to advancing regulatory goals. In the EERS proceeding, the utilities agreed to transition to decoupling (or to some similar mechanism) in the future because decoupling is better than the LRAM at balancing the interests of shareholders and those of ratepayers, and the Commission regarded this transition as appropriate as a package of reforms that included a significant increase in the savings goals of the state's ratepayer-funded energy efficiency programs.[19] In the EnergyNorth rate case, the Commission for the first time approved a decoupling

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[17] *See* DG 17-048, Johnson Direct at 7.
[18] *See* Order No. 26,122 (April 27, 2019) in DG 17-048 at 48 ("We agree with Staff that decoupling greatly increases the Company's ability to recover its fixed costs and therefore, we are comfortable with the significant decreases to the residential customer charges contained in the settlement.").
[19] *See* Order No. 25,932 (Aug. 2, 2016) in DE 15-137 at 54 (initial approval of the EERS and its initial triennium was "only the beginning of the EERS" with future dockets to "ensure that the energy efficiency programs funded by customers are indeed the least-cost resource") and 60 ("our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism" and the utilities must "seek approval of a decoupling or other lost-revenue recovery mechanism . . . in their first distribution rate cases after the first EERS triennium, *if not before*") (emphasis added).

mechanism outright – again not as an isolated reform but while ensuring that ratepayers received a tangible benefit through lowered residential customer charges and higher volumetric revenue recovery.[20]

1. Policy Analysis of Liberty's Decoupling Proposal

Q. Please explain Liberty's decoupling proposal as it relates to an alternative regulatory framework.

A. The Company indicates that its proposed decoupling mechanism will: (1) allow the Company to champion energy efficiency initiatives without the financial disincentives that currently exist; (2) better align with state policy goals related to energy efficiency; (3) realize the Company's commitment made in the EERS docket "by producing equitable ratemaking beyond the interim [LRAM] that fully supports the goals and enables full acceptance of the energy savings initiatives envisioned in the [DE 15-137] Settlement Agreement;" (4) aid the Company in earning a reasonable return while customer usage is declining; and (5) "enable the Company and New Hampshire stakeholders to implement innovative rate design in support of renewable DG, EV and other emerging technologies and electricity applications without the risk of over or under recovery of allowed revenue requirements."[21]

Q. What is your response to Liberty's framing of decoupling?

[20] *See* Order No. 26,122. April 27, 2018 in DG 17-048.
[21] *See* Mr. Therrien's Testimony, Bates II-253-254.

A. There are two significant shortcomings with Liberty's decoupling proposal.

First, Liberty does not acknowledge, and therefore does not address, the shortcomings of decoupling. This first issue is important for implementation purposes. Not explicitly identifying and addressing the shortcomings of decoupling will lead to poor implementation. Without optimal implementation, decoupling creates a sub-optimal regulatory framework that will not efficiently generate benefits for ratepayers.

Second, while the Company carefully articulated the potential benefits of decoupling, it failed to make tangible proposals that are reflective of decoupling's potential. Making tangible commitments at the time decoupling is implemented better ensures equitable balance between shareholders and ratepayers. Removing the disincentive for a utility to achieve policy goals is distinct from taking action to better achieve state policy goals.

Q. What shortcoming of decoupling did the Company fail to address?

A. The Company does not acknowledge that decoupling fails to address the utility's capital bias. Even though decoupling is not intended to focus directly on the utility's capital bias, regulators should address this shortcoming when integrating decoupling into the regulatory framework because of its relationship to the policy goals decoupling is designed to further. For example, a utility's capital bias can impact its incentive to achieve long-term energy efficiency goals because it can lead to lower capital expenditures.

There are multiple ways to address the utility's capital bias when implementing decoupling. One option, which New Hampshire is currently exploring, is to create a transparent Integrated Distribution Planning ("IDP") process. IDP helps address the utility's capital bias by improving transparency and democratizing the distribution system's investment prioritization process by including stakeholders and improving investment oversight.[22]

Although the development of the IDP process is underway in a separate proceeding, while awaiting the outcome of that docket it would be reasonable for Liberty to adopt incremental commitments that reflect decoupling's new influence over its incentive structure. Specifically, I recommend that Liberty commit to updating its interconnection standards. Doing so would demonstrate that the Company is committed to removing barriers to the adoption and integration of DERs and addressing the Company's capital bias. I discuss this recommendation in more depth in Section III.C.1.

Q. Regarding the second shortcoming of Liberty's decoupling proposal, did the Company explicitly link any proposals on policy issues to the approval of its decoupling mechanism?

A. Yes. The Company states that its proposed fixed charges were influenced by the request for a decoupling mechanism.[23] Specifically, the Company is proposing to

[22] *See* Testimony of Paul J. Alvarez and Dennis Stephens. (September 6, 2019) in IR 15-296.
[23] *See* Mr. Heintz's Testimony, Bates II-309.

increase the customer charge twice in this proceeding. The first increase would increase the customer charge from $14.02 to $14.76 and then to $15.50 at the same time as a step year adjustment goes into effect.[24] However, the Company requests the opportunity to propose higher fixed charges, if the Commission were to alter or deny the decoupling proposal. I am not aware of other policy-related matters that the Company linked directly to decoupling.[25]

Q. Did the Company's rate design proposals sufficiently embrace the changes that should accompany a decoupling mechanism?

A. No. In fact, by proposing two increases to the customer charge, Liberty's residential rate design proposal directly conflicts with past Commission precedent and state policy goals.[26] Additionally, Liberty does not make any significant proposals or discuss a plan to modernize commercial and industrial rate design. This lack of action on policy goals is precisely why regulators should expect more from a utility at the time it is decoupled.

Q. What should be the objective of implementing a decoupling mechanism?

A. The objective of decoupling should be to create a regulatory regime that enables utilities to continually improve performance related to rate design, DER integration,

[24] *See* Attachment DAH-9, Bates II-383-384.
[25] *See* Mr. Heintz's Testimony, Bates II-309. Additionally, the Company proposed an innovative residential rate design for electric vehicles but did not explicitly link the proposal to decoupling. I discuss the technical aspects of both proposals later in my testimony.
[26] See the residential rate design section of my testimony (Section VII) for additional discussion of this topic.

energy efficiency, and other state policy goals. To achieve this, the implementation and evaluation processes of decoupling should have a few distinct properties. First, the utility and ratepayers should receive benefits the first day of adoption. When decoupling is approved, utilities receive an immediate reduction in risk (i.e., a benefit). The same should be true for ratepayers through immediate improvements in rate design or progress on other state policy goals. Additionally, decoupling should continue to provide benefits to utilities and ratepayers throughout the entire time it is implemented. This means evaluating the progress that utilities have made on policy related goals every time decoupling is extended in a rate case. An iterative approach to decoupling is important because as long as decoupling is part of the regulatory regime, it will continually provide benefits to the utility while continued benefits for ratepayers is not a guarantee. For example, a single concession related to a policy goals, such as lowering the residential customer charge, should not be seen as a tradeoff for decades of operating within a decoupling regime. Instead, utilities should be committing to continuous improvement in rate design, DER integration, and energy efficiency and their progress should be considered when extending decoupling in rate cases.

The Commission's previous rulings, in the EERS and EnergyNorth proceedings, have embodied many of the principles that I have discussed. Primarily, the principle that improved utility revenue recovery should be paired with tangible policy actions to ensure ratepayers receive benefits from day one.

Q. Much of your discussion about making regulatory commitments related to decoupling has been focused on changes that benefit ratepayers; will your recommendations also benefit the utility?

A. Yes. Agreeing to additional regulatory commitments, in my view, insulates the utility from regulatory uncertainty by making regulatory objectives explicit.

In the next section, I recommend ways that the Commission can continue to strengthen the connection between a utility's improved revenue collection and its efforts to ensure benefits for ratepayers through the achievement of state policy goals.

C. Steps Toward a More Performance-Focused Regulatory Framework

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

A. The Commission should begin to conceptualize decoupling as a step towards a more performance-focused regulatory framework. Additionally, via their respectively pending rate cases Liberty and Eversource 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 DR PIM.

1. 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 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. Why is requiring decoupled utilities to analyze and implement CVR **reasonable?**

A. CVR has been demonstrated to be cost-effective for numerous utilities in most, if not all, regions of the country.[27] Results have demonstrated that CVR can shave 5 percent off peak demand and achieve energy savings of over 3 percent.[28] There is clearly potential to create benefits for ratepayers through the implementation of CVR. Given the connection of CVR to energy efficiency and demand savings, decoupling should remove the disincentive for utilities to implement CVR rapidly.

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[27] *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

[28] *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/.

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 example, utilities can operate CVR only during times of high demand. This may maximize demand-related savings but may lower energy savings. 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 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. 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).

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 is established before the Commission approves a MYRP or IDP cost recovery rider.

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 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 time of use ("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 and as a qualitative measure of performance.

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.[29] While interconnection has not been directly breached by the OCA

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

in previous comments because it is an emergent policy issue, it has previously supported the cost-effective integration of DERs.[30] 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.[31]

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 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. While I recommend adopting the recommendations above, I note that additional performance metrics could be reasonably adopted in the grid modernization docket.

2. Demand Response PIM

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

[30] *See* Testimony of Lon Huber filed in DE 16-576 (Oct. 24, 2016).
[31] *See* DE 16-576. OCA Comments at 2. Filed August 10, 2019.

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.[32]

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 dispatch to reduce a small number of key system demand peaks. These system peaks contribute significantly to system resource needs, but result in construction of resources with relatively low utilization rates and 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 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

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

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 EV load is likely duplicative.[33]

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 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.[34]

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

[33] 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.
[34] *See* Docket No. DE 16-576, OCA Comments at 7. Filed March 8, 2019.

the Granite State Test[35]; (2) administer future demand response programs through the new DR PIM, not through the EERS; (3) fund the incentive and programs through a separate mechanism, 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 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. The objective of any PIM is to better align utility, shareholder, and ratepayer incentives. Administering and incentivizing DR programs through the

[35] *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).

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 would DR PIM based on shared savings be an improvement compared to the EERS mechanism?

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. 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 intended also to 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 mechanism 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.[36] 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.

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

IV. DECOUPLING – TECHNICAL ANALYSIS

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

A. In this section, I discuss and analyze the technical aspects of the decoupling mechanism, as opposed to the associated policy implications.

Q. Please explain the technical aspects of Liberty's decoupling proposal.

A. The Company is proposing a revenue per customer ("RPC") decoupling mechanism to be applied to all firm rate classes.[37] Rate classes will have distinct targeted RPCs with over and under recovery calculations each month. The accruals from all rate classes will be accumulated annually and refunded or collected from customers through a uniform kWh rate. The decoupling mechanism will capture all variances in customer usage, including weather-related variances. This is commonly referred to as full decoupling.[38]

Q. Do you find the Company's proposed decoupling mechanism to be optimally designed?

A. No. The design is largely reasonable, but I believe it could be improved in at least three ways. First, the annual decoupling adjustment should be modified by allocating the annual over or under collection among rate classes using a total revenues allocator. Second, annual adjustments should have a soft cap of 3 percent. Lastly, for rate classes

[37] *See* Mr. Therrien's Testimony, Bates II-281.
[38] *See* Mr. Therrien's Testimony, Bates II-283.

that utilize time-varying rates, the decoupling surcharge should be applied to the peak period and any refund should be applied to the off-peak period.

Q. How is the Company currently allocating over and under collection through the decoupling rate adjustment?

A. The Company is using an energy allocator to allocate annual over and under collections.[39] This is evidenced by the fact that the over or under collection is divided by total annual kWh to create the rate adjustment.

Q. What concerns you about the Company's proposal to allocate annual under and over collections using an energy allocator?

A. A combination of factors could lead to the Company's proposal benefiting large energy users at the expense of smaller customers.

In years where there is a systemwide over collection, large customer (G1 and G2) would be credited the vast majority (approximately 58 percent) of the rate refund, while representing under 2.5 percent of the customers. Assume, for example, that the hypothetical surcharges were refunds in Witness Therrien's Attachment GHT-3 and Table 5 of his direct testimony. In 2018, Residential customers would have been responsible approximately $500,000 of the total systems over collection of $611,000.

[39] *See* Mr. Therrien's Testimony, Bates II-285.

However, approximately $350,000 of the total refunds would be allocated to large customers and only $185,000 to residents.[40] This is clearly an unreasonable result.[41]

If there are consistent refunds, the Company's decoupling mechanism will shift revenue collection from large customers to small customers. Consistent refunds are possible, given New Hampshire's electrification goals.[42] This component of the Company's decoupling design is inequitable and unreasonable.

Q. Why should the annual over and under collections be allocated using a total revenue allocator?

A. Given that the over and under collections will be accumulated at the total revenues level to calculate the rate adjustment, the over and under collection should also be allocated back to the classes on a total revenues basis. Using a total revenues allocator has more symmetry than the approach proposed by the Company.

Additionally, the Regulatory Assistance Project ("RAP") has conducted extensive research on decoupling. RAP recommends mechanisms that "allocate the adjustment based on the customer classes' percentage contribution to total revenues" when "all customer classes are involved."[43] For these reasons, the decoupling mechanism should

[40] *See* Schedule REN-2.
[41] The reverse is also unreasonable because large customers would be burden with unproportionally large surcharges.
[42] Electrification will also make forecasting more difficult, given changes in customer load profiles.
[43] Janine Migden-Ostrander and rich Sedano, "Decoupling Design: Customizing Revenue Regulation to Your State's Priorities," The Regulatory Assistance Project (November 2016) at 36.

administer refunds and surcharges using a total revenues allocator, not an energy allocator.

Q. Why should annual adjustments be limited to a soft cap of at 3 percent?

A. Any regulatory mechanism, such as a PIM or decoupling, that has the potential to have significant impact on customers financially should have some boundaries as a consumer protection measure. The bounds of a regulatory mechanism should be fair to all parties and designed so that it is triggered rarely. For that reason, I am recommending a soft cap of 3 percent on surcharges and refunds. The Company's retrospective decoupling adjustment analysis demonstrates that the 3 percent soft cap would not have been hit in the past 5 years.[44]

Additionally, a soft cap has the benefit of preserving absolute symmetry for the utility and ratepayers. In years that adjustments are greater than 3 percent, the excess amount will roll over in the following year's adjustment. Based on the information provided by the Company, this should not occur frequently.

Q. Please explain how the decoupling surcharges and refunds should be used to strengthen the Company's existing rate design.

A. For the two rate classes with TOU rates, decoupling surcharges should be applied to the on-peak period and credits should be applied to the off-peak period. Applying surcharges and credits in this way will reinforce policy goals that decoupling

[44] See Attachment REN-1.

is meant to promote. For example, in years with surcharges, customers on TOU rates will receive their surcharge through the on-peak period price. This will strengthen price signals, while the 3 percent soft cap protects customers from rate shock. In years with refunds, they will be applied to off-peak period. This will increase customer's incentive to consume during off-peak times.

Q. What is your recommendation related to the technical components of Liberty's decoupling mechanism?

A. I recommend that the Commission adopt Liberty's decoupling with the three modifications proposed in this section.

V. MARGINAL COST OF SERVICE STUDY

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

Q. Before you discuss the details of a Marginal Cost of Service Study (MCOSS), 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.

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.[45]

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

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 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 Liberty 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. Background and Objectives

Q. What is an MCOSS?

A. An MCOSS is used to determine the portion of demand and customer-related costs in relation to total distribution system costs for which each customer class is responsible, and the way 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.[46]

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, growth to noncoincident system peak – over a particular time horizon.[47] These planned expenses and investments are divided by load growth in order to calculate a marginal dollar per kilowatt cost.

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

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. The National Association of Regulatory Utility Commissioners ("NARUC") has observed that system investments tend to be "lumpy," meaning that investment occurring in one year is not only related to 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," according to the NARUC Electric Manual.[48]

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. Have utilities in New Hampshire used one of these MCOSS approaches to inform rates?

[48] NARUC (1992) at 129.

A. Yes. In Liberty's last electric rate case, Docket No. DE 16-383, the Company used three-year historical average costs for 11 out of 14 cost categories.[49] However, in this case, the Company is using regression to estimate marginal costs.

Q. Why did the Company choose to use a regression-based approach to estimate marginal costs in this case?

A. The Commission adopted the settlement agreement in DE 16-383, in which Liberty agreed to use the regression approach.[50]

Q. In the previous case, did the Company take any relevant positions related to the approaches it used?

A. Yes. There are a few positions that the Company took in its last case that demonstrate the subjective nature of cost studies.

First, the Company noted that its consultants could not create regressions that made sense in that case.[51] In this case, however, the consultants appear to have run numerous combinations of regressions until an acceptable result was achieved.[52] I critique this approach below.

Second, the Company fiercely defended the use of the 3-year average approach. The Company argued that the 3-year average approach was superior to the regression

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[49] *See* Ms. Bartos' Testimony Bates II-395 lines 16-17.
[50] *See* Order No. 26,005 (April 12, 2017) in DE 16-383.
[51] *See* DE 16-383, Tebbetts and Simpson Rebuttal, Bates at 274 and 276.
[52] *See* Ms. Bartos' Testimony, Bates II-399.

approach in that case. It also took the position that a critical decision, using a 3-year versus a 5-year average, was not subjective.[53] As discussed above, there is a never-ending list of subjective decisions in the MCOSS, and in this case the Company is firmly relying on regression analysis which is "*judgmental and subjective by nature*."[54] In fact, the Company's consultant stated that it, "understands the need to use creative and innovative approaches to deal with shifts in expense and plant data that relate to changes in company operations or record keeping practices" when running regressions.[55] Clearly, using creativity and innovation when specifying regressions requires subjective decisions that are unrelated to economic theory.

In this case, the Company is essentially arguing the opposite of its previous position—that only regression analysis should be considered.[56] In fact, the Company did not even calculate a 3- or 5-year average to check against the method that it found to be nonsensical in the last case.

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 MCOSS approaches and conduct sensitivity analysis around key assumptions.

[53] Tebbetts and Simpson Rebuttal, Bates at 277-278.
[54] Studenmund at 404. Excerpt is from the "Practical Advice for Applied Econometrician" section.
[55] See Attachment REN-3.
[56] See Attachment REN-2.

C. Liberty's MCOSS Approach and Results

Q. Please summarize Liberty's MCOSS approach.

A. Liberty Witness Melissa Bartos used a projected embedded MCOSS approach with regression analysis. In other words, the Company regressed various categories of distribution system costs on variables including kW of peak demand or number of Liberty customers, using Liberty's annual data from 1997 to the present.

Witness Bartos adjusted the historical cost data to restate plant additions and expenses into constant 2018 dollars.[57] Witness Bartos then calculated capacity-related marginal distribution costs from both plant investments and operations and maintenance (O&M) expenses. Witness Bartos separately calculated customer-related marginal distribution costs from both plant additions and O&M expenses. Lastly, Witness Bartos calculated and applied loading factors, utilized fixed charge carrying rates, and used loss factors to better allocate costs between different voltage levels.

Q. How did Witness Bartos separate the customer- and demand-related costs in the MCOSS?

A. Witness Bartos used Company-provided meter and service cost data to represent the plant additions related to customers used. Witness Bartos also used Company-provided data to determine plant additions related to capacity. To distinguish between types of expenses, analysis from the Company separated O&M costs as either capacity-

[57] See Ms. Bartos' Testimony Bates II-397,lines 6-9.

related or customer-related.[58] Witness Bartos did not provide further detail on these Company analyses.

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

A. Witness Bartos used analyses from the Company that identified capacity-related distribution plant additions that are specifically associated with demand growth, and then separated those plant additions into categories: primary distribution system, secondary distribution system and line transformers.[59] Additional Company analysis separated capacity-related O&M expenses into the same three categories.[60]

Witness Bartos then regressed the three growth-related, demand-driven plant addition categories, and growth-related, demand-driven expenses (operations and maintenance regressed separately) on peak demand variables, to find the marginal cost of each incremental unit of peak demand.

Q. How did Witness Bartos calculate the cost of incremental customers?

A. Witness Bartos "asked the Company to provide an analysis of the current installed cost of a meter and installed cost of a service that is typical for each rate class."[61] This representative class cost is the marginal customer-related plant addition cost.

[58] *See* Ms. Bartos' Testimony Bates II-397, lines 14-16.
[59] *See* Ms. Bartos' Testimony Bates II-397, lines 10-13.
[60] *See* Ms. Bartos' Testimony Bates II-397, lines 16-18.
[61] See Ms. Bartos' Testimony Bates II-402, lines 5-7.

Witness Bartos regressed O&M and customer accounting expenses on the number of annual customers. In order to differentiate these marginal expenses by rate class, Witness Bartos additionally weighted each expense regression result by the relative costs of service and meter plant per customer class that was already determined from Company data. Witness Bartos also class-weighted bad debt accounts expenses.

D. Analysis

Q. Did you review the Company's proposed MCOSS?

A. Yes. My review focused on the regression analysis conducted by the utility. I found the Company's theoretical approach to regression analysis to be highly questionable. Additionally, I found that many of the specifications for the regression analyses did not follow best practices, while some were simply not explained and confusing as to why certain variables were used in the model.

Q. What was your impression of the Company's MCOSS analysis?

A. The Company's MCOSS is overly reliant on highly problematic regression analysis. While I understand the Company was ordered to use such analysis, the Commission did not prohibit the Company from comparing its results to an alternative method, including the method the Company argued was more reasonable two years ago. The difference between the two methodologies employed over the last two rate cases supports using multiple cost studies to inform rates and revenue apportionment, while not putting too much weight on any one model.

The wildly different regression specifications suggest data mining. This occurs when an analyst "tailors one's specification to the data, resulting in a specification that is misleading because it embodies the peculiarities of the particular data at hand," but the same specification would not provide similar results when applied to another similar data set.[62] An example that strongly suggests data mining is that the Company uses different regression specifications on primary and secondary distribution equipment. Economic theory would suggest similar, if not the same, variables as predictors of these costs. Additionally, the accounting methods used to create this data should be consistent, and not result in structural changes.[63]

Q. Can you provide some examples of the model specification with which you did not agree?

A. Yes. To estimate the marginal cost of administrative and general expenses the Company used six dummy variables—all related to structure change. In fact, the Company's model suggests the data had a structural change for almost every year for six consecutive years—but there is no theoretical support for this.

The Company also used different versions of a peak demand variable in numerous regressions, such as lagged and two-year averaged peak demand variables. However, the Company provided no discussion or justification of these variable in its testimony. Transforming variables like this requires an explanation because it likely

[62] A. H. Studenmund, *Using Econometrics: A Practical Guide* (5th ed., 2006) at 408.
[63] As noted previously, the structural change caused by the acquisition is plausible.

drastically alters results. For example, given that ordinary least squares regression is a measure of variance, averaging an independent variable necessarily inflates R-squared, which is a measure of model fit that the Company heavily relied upon to justify model specifications. These transformations should not be accepted without detailed explanation that aligns with the economic theory underpinning the regression.

Q. Why is it problematic to add dummy and autoregressive variables when they do not belong in the regression?

A. Unnecessarily adding variables to regressions inflates R-squared and can give analysts a false sense that the independent variables explain the variance of the dependent variable.

1. 3-year Average Diverges Greatly from the Regression Results

Q. Did you request that the Company compare its regression results to a three-year average, as was filed in its last rate case?

A. Yes. The results of the method that Liberty used a short time ago, a three-year average, differed greatly from the regression results relied upon in this case. The table below provides a summary.

Table 1. [64,65]

COST CATEGORY		3 Year Average (for 2016-2018)	Regression Coefficient in This Case	Units
Plant Additions	Primary	$236,767	$115,690	per MW
Plant Additions	Secondary	$52,808	$82,116	per MW
Plant Additions	Line Transformers	$70,892	$84,022	per MW
Operations	Primary	$8,587	$35,927	per MW
Operations	Secondary	$3,000	$3,410	per MW
Operations	Line Transformers	$498	$1,458	per MW
Maintenance	Primary	$8,047	$16,349	per MW
Maintenance	Secondary	$3,052	$9,625	per MW
Maintenance	Line Transformers	$1,480	$2,846	per MW
O&M	Customer	$74.79	$132.40	per customer
Customer Accounts Expense		$54.89	$109.64	per customer

Q. What are some takeaways from Table 1?

A. Table 1 demonstrates that the marginal costs calculated in this case are two to three times higher using the Company's previous approach. It also demonstrates that Primary Plant Additions, which are heavily allocated to large customers, decreased by approximately 50 percent. At the same time, customer costs, which are heavily allocated to residential customers, increased by approximately 200 percent. This indicates that the marginal cost approach used in this case, when compared to the previous cases approach, would allocate more of the revenue requirement to residents than to large customer classes.

Q. Did you expect the two marginal cost approaches to be similar?

[64] See Attachment REN-2.
[65] See Attachment REN-4.

A. The results should not be exactly the same. Theoretically, however, a three-year average should be somewhat close to the regression results—and they are not.

E. Utilizing Cost Study Results in Practice

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

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

Q. What concerns has the Massachusetts Department of Public Utilities ("MA DPU") had with MCOSS in the past?

A. The Massachusetts DPU has previously criticized the utilities' use of dummy and autoregressive variables—very similar to the issue in this case.[66] The Massachusetts DPU made its opinion explicit in the 2017 rate case proceeding of Eversource Energy, when the DPU ordered "all electric and gas companies to limit the number of dummy variables and autoregressive terms or, alternatively, provide justification … ."[67] The Massachusetts DPU found the order to be necessary because "the extensive use of dummy variables and autoregressive terms in a regression analysis may not lead to the development of a model with the best predictive powers."[68]

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[66] In fact, the MCOSS was sponsored by Witness Bartos in that case as well.
[67] Order Establishing Eversource's Rate Structure. D.P.U. 17-05-B. p.14-15.
[68] Order Establishing Eversource's Rate Structure. D.P.U. 17-05-B. p.14.

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

A. No. Per the 2018 rate case proceeding of National Grid, "as a practical matter, the Department does not rely on a marginal cost study in designing rates for electric and gas distribution companies."[69] 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."[70] 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."[71]

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

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 a 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

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[69] Order in D.P.U. 18-150. p.516.
[70] Order in D.P.U. 18-150. p.517.
[71] Order in D.P.U. 18-150. p.517.

revenues"[72] 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."[73]

Q. What are your recommendations related to the MCOSS?

A. I provide a few recommendations for the Commission to consider. I begin with my primary recommendation, but also discuss some alternatives that the Commission may also wish to consider.

To better inform revenue apportionment and rate design, I recommend that the Commission consider multiple cost studies. Relying on multiple studies will provide the Commission with a range of results that can be used to inform revenue

[72] 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. p.45.
[73] 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.

apportionment and rate design. Specifically, I suggest that the Company be required to file both marginal and embedded cost studies in its next rate case. As for the MCOS, I recommend that the Company be required to use a planning approach to estimate marginal costs. The regression and averaging approaches that have been utilized previously by the Company add vary little, if any, valuable information to the revenue apportionment and rate design process.

In future rate cases, if the Commission is relying 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 design rates.

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

VI. **REVENUE APPORTIONMENT**

Q. How did the Company arrive at its proposed class revenue targets?

A. The Company utilized the results of the MCOSS as a basis for the class revenue targets. It went through a series of steps to obtain the proposed class revenue including assigning a rate increase cap and adjusting class rate components using the equi-proportional approach.[74]

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

A. No. I do not agree with the Company's proposed class revenue targets for a few reasons—all stemming from the Company's proposed MCOSS. First, given the numerous flaws within the MCOSS, I do not find it reasonable to use it as a starting point for class revenue targets. Second, I find it concerning that the methods utilized by the Company resulted in significantly different results from the method used in its last case. These significantly different results shift large portions of revenue between classes with no explanation from the Company. As discussed in the section above, the Company completely ignored the analysis it fiercely defended a short time ago. For these reasons, I do not find the proposed class revenue targets reasonable.

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

A. I do not find the evidence put into the record to provide sufficient support for class specific revenue targets. For that reason, I recommend that the Commission equally apply any rate increase across classes.

[74] *See* Mr. Heintz's Testimony, Bates II 304-306.

VII. RATE DESIGN

Q. How is this section of your testimony organized?

A. In Section VII.A., I address the Company's proposed residential rate design changes and make alternative recommendations. In Section VII.B, I discuss Rate D-EV and the classification of advanced meters.

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

A. Yes. I considered the rate design principles set out in the Staff Recommendation on Grid Modernization[75] and EERS.[76] I also considered the federal Energy Policy Act of 2005 (EPACT 2005) and the Commission's implementation order.[77]

A. Residential Rate Design

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

A. The Company has proposed to increase the customer charges for residential classes D and D-10 once for permanent rates and then again if the step adjustment is approved. Specifically, the Company is proposing to increase the customer charge from \$14.02 to \$14.76 and then to \$15.50.[78]

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[75] "Staff Recommendation on Grid Modernization" (Feb 12, 2019) in IR 15-296 at 49.
[76] Energy Efficiency Resource Standard Settlement Agreement. DE 15-137 at 6. Filed April 27, 2016.
[77] *See* Order No. 24,893 (Sept. 15, 2008) in Docket DE 06-061 (noting that the standards recommended for state adoption concerned net metering, fuel diversity, fossil fuel generation efficiency, time-of-use pricing, advanced metering infrastructure, and interconnection).
[78] *See* Attachment DAH-9, Bates II-383-384.

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

A. The Company appears to base its recommendation a couple of claims. First, the Company claimed that the marginal unit customer costs exceed its proposed increase.[79] Second, the Company claims that its proposal is consistent with the rate design approach in the EnergyNorth rate case, which included a decoupling mechanism.[80] I do not find either of these reasons persuasive support for the Company's proposed increase the residential customer charge.

Q. Why do you find the Company's reliance on marginal unit customer costs unpersuasive?

A. As indicated in the section above, the Company's MCOSS is highly flawed. Additionally, the approach relied upon, and fiercely defended, by the Company in its previous rate case results in a vastly different calculation of marginal unit customer costs. As displayed in Table 1, the Company's method approximately doubled some marginal customer costs.

Q. Please respond to the Company's claim that its proposal is consistent with the previous EnergyNorth rate case.

[79] *See* Mr. Heintz's Testimony, Bates II-308, lines 13-14.
[80] *See* Mr. Therrien's Testimony, Bates II-262.

A. The Company's characterization in its testimony appears accurate, but misleading. Specifically, the Company states, "[t]he proposed rate design holds fixed charges flat after the temporary rate across-the board [sic] percentage increase. Although the MCS clearly indicates that current fixed monthly rates are significantly below costs, the Company recognizes that a rate design with volumetric rates may help send a price signal to conserve usage. This is a similar approach to the EnergyNorth rate design that accompanied the approved decoupling mechanism in that case."[81]

First of all, the Company claims that it "holds fixed charges flat after the temporary rate across-the board [sic] percentage increase."[82] However, the Company is proposing a customer charge increase for the step adjustment. I do not find these statements consistent.

Second, the Company states that it is proposing the same approach as that in EnergyNorth. However, the Company does not note the fact that the customer charge increases it proposed in that case were not only rejected, they were modified to lower the residential customer charge.[83] I not only do not find the Company's claim persuasive, I find that the previous Commission order suggests that the opposite result, a customer charge decrease, is more reasonable.

[81] Heintz Direct at 9. Bates II-309.
[82] Heintz Direct at 9. Bates II-309.
[83] Order No. 26,122 (April 27, 2018) in Docket DG 17-048.

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

A. I recommend that the residential customer charges be reduced to $10 for both D and D-10 classes.

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 couple of reasons. First, the Company's calculation of marginal customer costs relies on unreasonable regression results for numerous inputs, such as administration and general expense, plant related O&M and loading factors. Second, lowering the customer charge is more consistent with Commission precedent, its rate design principles, and state policy goals related to energy efficiency and conservation.

Q. Do you have clarifications that you would like to request that the Company make in rebuttal?

A. Yes. Witness Bartos indicated that the cost of meters was provided by the Company and that these costs are "typical."[84] I would like the Company to confirm that a standard residential meter is $105, or about double the cost of Eversource's standard residential meter.

[84] *See* Ms. Bartos' Testimony Bates II-402, line 7.

B. Rate D-EV and Classifying Advanced Meters

Q. Did you review the Company's proposed Rate D-EV?

A. Yes. I must begin by giving the Company recognition for proactively proposing a TOU EV rate with strong price signals. I have worked on EV rate design in many states and this is not common practice. Liberty is making a clear commitment to achieving state policy goals with its Rate D-EV proposal.

Q. Are there any changes that you would suggest for the Rate D-EV?

A. Yes. I have one recommendation related to the customer charge associated with Rate D-EV. To understand the justification for the change, I need to explain how traditional meters have been traditionally classified and allocated in cost of service studies and explain why traditional thinking should no longer apply to advanced meters.

Q. How have meters traditionally been classified within cost of service studies?

A. According to the NARUC Electric Manual, the costs of meters, or FERC account 370, "are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment."[85]

Q. Why are large-usage customers' meters more expensive?

[85] NARUC (1992) at 97.

A. Large customers' meters are more expensive for many reasons, but generally larger-usage customers' meters have additional functionalities enabled when compared to residential meters.

Q. What were the differences in functionality?

A. At the time the NARUC Electric Manual was written—over two-and-a-half decades ago—most residential and small business customers had "dumb meters." Dumb meters only measured energy use and required meter readers to drive to the physical location of the meter to obtain a reading. On the other hand, large-usage customers had meters that measured demand-related requirements and sometimes recorded energy consumption on time intervals such as every 15 minutes (as opposed to residential energy measurement that had just one aggregate reading every month).

Q. What is the reasoning behind the two recommended classifications in the NARUC Electric Manual?

A. The functionality of the meters drove the cost causation. Large customers were on more advanced rate designs that required additional metering functionality such as measuring demand. The additional metering functionality increased the expense of the meter.

Q. Why does classifying meters as demand related align with cost causation?

A. Meters that can measure demand, or more granular interval data, can be used to mitigate demand-related costs through price signals. For example, large customer classes often have demand charges and TOU rates. Demand charges incent customers to have higher load factors in order to reduce the costs caused to the power system, while TOU rates encourage load shifting. For this reason, the NARUC Electric Manual finds it reasonable to classify meters as demand because of the enhanced functionality associated with advanced metering.

Q. How does Liberty classify meters?

A. The Company classifies residential meters as customer related.

Q. Are the costs of Liberty's meters for Rate D-EV directly caused by the number of customers?

A. No. The incremental cost above that of a standard meter is to enable TOU and data transfer.

Q. What type of enhanced functionality do the Rate D-EV meters have compared to standard residential meters?

A. Compared to the standard residential meters, the Rate D-EV meters have enhanced functionality related to both energy and demand related costs. For example, Liberty's AMI meters have enabled the Company to be able to offer advanced time-based customer rates. Utilizing the additional meter functionality creates benefits by avoiding energy- and demand-related costs. For instance, both time-based rates and improved load control can decrease the need for future generation and transmission investments, which are both 100 percent energy and capacity related.

Q. How do you recommend the Company's meters be classified for Rate D-EV?

A. The incremental cost of the Rate D-EV meter should be classified as demand related and allocated to the mid-peak and critical peak periods to strengthen the price signal. While it would be reasonable to classify and/or allocate a portion of advanced meters as energy related, this portion would theoretically be much smaller than the demand and customer portions.

Q. How does your recommendation change the customer charge for Rate D-EV?

A. Assuming that the standard residential meter costs $105, the meter related portion of the customer charge would fall from $6.46 to $1.52.[86] The $5 cellular data charge would remain the same resulting in a $6.52 customer charge for Rate D-EV.

Q. Do you have references to support your recommendation?

A. Yes. Other than the NARUC Electric Manual, there are two recent publications that recommend classifying AMI differently than dumb meters. First, the RAP's Smart Rate Design for a Smart Future report discusses this in multiple sections. RAP suggests that the "additional cost of smart [also known as AMI] meters is justified by many benefits beyond the simple measurement of usage . . . and this additional cost is not properly considered customer related."[87] RAP notes that AMI meters "are installed one per customer, but the purpose of deployment is to enable time-varying rates, to

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[86] *See* Schedule REN-3.
[87] Smart Rate Design for a Smart Future, Appendix D at D-6.

enable demand response programs and to enable critical peak pricing schemes."[8861] For these reasons, RAP recommends classifying AMI meters as energy, demand and customer costs.[89]

The second reference is a report produced by the Rocky Mountain Institute ("RMI"). In the report RMI states, "[i]n some situations, a portion of AMI (and other smart-grid infrastructure) costs may be appropriately recovered through energy or demand charges."[90] While the report does not provide the detail that a cost of service analysis provides, RMI's comment acknowledges that classifying AMI meters and other grid modernization assets as both energy and demand related is appropriate.

Q. Do you have any other observations related to Rate EV-D?

A. Yes. In conversations with the Company, I inquired as to whether it had considered using smart inverter functionality for billing and/or load control purposes. Smart inverters are found in both the vehicle themselves and within smart chargers. Either smart inverter could potentially be used as a substitute for a meter and as a load control mechanism. The Company indicated that it had done some cursory research and found that it was not a feasible solution at this time.

While using smart inverters for metering and load control may not be cost-effective for a utility of Liberty's size, this technology should be kept in mind for future

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[88] Smart Rate Design for a Smart Future, Appendix A at A-6.
[89] Smart Rate Design for a Smart Future, Appendix A at A-4.
[90] Rocky Mountain Institute, *A Review of Alternative Rate Designs: Industry Experience with Time-Based and Demand Charge Rates for Mass-Market Customers*, 54 (2016).

use. Leveraging smart inverter functionality has significant potential for decreasing the cost of integrating EVs and other DERs.

VIII. CONCLUSION

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

A. My recommendations and conclusions 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. Effective implementation of decoupling should include:
    a. a timeline for analyzing and, when cost-effective, implementing Conservation Voltage Reduction
    b. a timeline for updating DER interconnection standards
    c. more specific advanced rate designs
3. Liberty's proposed revenue decoupling mechanism should be modified in the following three ways:
    a. administer refunds and surcharges using a total revenues allocator, not an energy allocator
    b. use an annual soft cap of 3 percent for surcharges and refunds
    c. for rate classes with time-of-use ("TOU") rates, decoupling surcharges should be applied to the on-peak period and credits should be applied to the off-peak period
4. In future rate case filings, the Company should be required to file both marginal and embedded cost studies.
5. Rate increases should be apportioned equally across customer classes.
6. For residential classes, the customer charge should be reduced to $10.
7. For Rate D-EV, the fixed charge should be reduced to $6.52.

Q. Does this conclude your direct testimony?

A. Yes.