Liberty Utilities

EXHIBIT
#27A
DG 17-048

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-048

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Distribution Service Rate Case

REBUTTAL TESTIMONY

OF

GREGG H. THERRIEN

January 25, 2018

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE OF CONTENTS

THIS PAGE INTENTIONALLY LEFT BLANK

I. INTRODUCTION

Q. Please state your name, address, and position.

A. My name is Gregg H. Therrien. I am an Assistant Vice President with Concentric Energy Advisors, 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752. My professional qualifications and experience have been provided in Attachment GHT/DECPL-11 to my Direct Testimony filed April 28, 2017.

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

A. No, I have not.

Q. Did you participate in the PUC technical sessions in the instant case?

A. Yes. I participated in both the August 24, 2017, and November 1, 2017, technical sessions at the Commission's office.

Q. What is your responsibility in this proceeding?

A. In this proceeding, I am responsible for: (1) designing the Revenue Decoupling Mechanism (direct Decoupling Testimony of Gregg H. Therrien) and (2) together with Company Witness David Simek, developing the rate design (direct Joint Rate Design Testimony of David B. Simek and Gregg H. Therrien) for Liberty Utilities (EnergyNorth Natural Gas Corp.) d/b/a Liberty Utilities ("EnergyNorth" or the "Company").

II. SCOPE OF REBUTTAL TESTIMONY

Q. Please summarize the scope of this rebuttal testimony.

A. In this testimony, I:

1) Reaffirm why full revenue decoupling, inclusive of weather and economic adjustment, is superior to Commission Staff ("Staff") witness Mr. Iqbal's proposed weather-normalized limited Revenue Decoupling Mechanism ("RDM");
2) Respond to Mr. Iqbal's five other proposed changes to the Company's decoupling proposal;
3) Respond to the Office of Consumer Advocate's ("OCA") proposed modifications to the Company's decoupling proposal, including the proposed "real-time" adjustment;
4) Rebut the OCA's position that the RDM should be calculated on a total revenue basis rather than on a per-customer basis;
5) Rebut the OCA witness Dr. Johnson's assertions that decoupling improves earnings;
6) Rebut both Staff and OCA witnesses' recommendation for inclining block rate design and lower customer charges; and
7) Respond to Staff witness Mr. Frink's recommended changes to the Low-Income Discount Program.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows:

As stated in my Direct Testimony, the decoupling rate design measures that the Company is proposing:

- Will allow the Company to remain an effective champion of energy efficiency initiatives without the financial disincentives that currently exist;
- Will comport with the State of New Hampshire's vision in its 2014 State Energy Strategy, which recognized that "[r]ealigning utility incentives to reward utilities for investing in efficiency is a necessary part of any effort to increase efficiency in New Hampshire"; [1]
- Will realize the vision crafted by the Settling Parties in the Energy Efficiency Resource Standards ("EERS") docket[2] by producing equitable ratemaking beyond the interim Lost Revenue Adjustment Mechanism ("LRAM") that fully supports the goals, and enable full acceptance of the energy savings initiatives envisioned in the Settlement Agreement; and
- Will fix a flaw in the traditional ratemaking methodology that does not allow utilities a reasonable opportunity to earn a reasonable return when customer usage is declining.

---

1 New Hampshire 10-Year State Energy Strategy, published by the New Hampshire Office of Energy & Planning September 2014. Executive Summary, page ii.

2 The "Settling Parties" as defined in the Settlement Agreement approved in Docket No. DG 15-137, dated August 2, 2016, include: Commission Staff; Liberty Utilities (Granite State Electric) Corp.; Unitil Energy Systems, Inc.; Public Service Company of New Hampshire d/b/a Eversource Energy; the New Hampshire Electric Cooperative, Inc. Liberty Utilities (EnergyNorth Natural Gas) Corp.; Northern Utilities, Inc.; the Office of the Consumer Advocate; the Department of Environmental Services; the Office of Energy and Planning (OEP); New Hampshire Community Action Association; The Way Home; the Conservation Law Foundation; The Jordan Institute; Acadia Center; the New Hampshire Sustainable Energy Association; the New England Clean Energy Council; the NH Community Development Finance Authority; and TRC Energy Services.

Further, as discussed in detail in this Rebuttal Testimony, I conclude and recommend that:

- Staff's proposed limited decoupling mechanism is not in the best interests of customers as it does not sever the relationship between sales volumes and revenues, thus limiting the effectiveness of decoupling. As a result, Staff's proposal does not maximize the benefits of decoupling envisioned in the EERS Settlement.
- 67 U.S. gas distribution companies have implemented RDMs in 29 different states; decoupling has become the mainstream regulatory framework in support of energy efficiency goals. The majority of these RDMs are constructed the same as the Company's proposal.
- The Company agrees with the OCA that a real-time RDM is better for customers in matching the impact of weather on bills, and is mutually beneficial to customers and the Company's cash flows. The Company does not, however, agree with OCA that a "Total Revenue" RDM is appropriate for EnergyNorth, because the Company has experienced dramatic growth in customers in recent years, which is forecasted to continue. Ignoring the revenue requirement associated with new customer additions is contrary to the Commission's approved natural gas expansion policy, evidenced through the approved Managed Expansion Program "MEP" and associated expansion rates.
- Inclining block delivery rates alone do not send a significant price signal to encourage conservation. This change would undermine long-standing rate design

principles such as cost causation. Further, the Commission should approve the Company's proposal to align Residential Non-Heating and Residential Heating fixed customer charges considering the significant shortfall in these rates compared to the results of the Marginal Cost Study ("MCS")[3].

- The Staff's proposal to modify the Low-Income Discount Program should be deferred. The Company respectfully requests that the Commission reject this change in the instant proceeding and open a separate generic docket to fully evaluate any change (if necessary) to this important program.

Q. How is the remainder of your testimony organized?

A. Section III of this testimony addresses decoupling issues raised by Staff and the OCA, and where appropriate, rebuts assertions made by these Parties. Section IV specifically addresses rate design issues. Section V will address Staff's recommended changes to the Low-Income Program. Finally, Section VI summarizes this rebuttal testimony.

III. DECOUPLING

A. Summary of Staff's Recommendations

Q. Please describe the six modifications to the Company's RDM proposed by Staff.

A. Staff proposed the following six modifications to the Company's RDM proposal:

1) The adjustment should be based on weather normalized revenues.

---

[3] In the case of Residential rates, the MCS results are approximately three times higher than current monthly customer charges.

2) The adjustment should be performed at the rate class level (instead of at the company level).

3) Expected revenue should be calculated at individual rate class level, not at combined rate class level.

4) Expansion rate customers should be included in the RDM calculation.

5) Annual RDM adjustments should be capped at +/- 2 percent.

6) No mid-period adjustment should be made; if needed, an adjustment could be made at the time of Company's next rate case.[4]

Q. Please summarize the Company's response to Staff's recommendations.

A. As explained in detail below, the Company strongly disagrees with Staff's recommendation that the RDM adjustments should be based on weather normalized revenues. The Company accepts Staff's recommendation Nos. 2 and 3 related to the method of calculating the RDM accrual and the RDM billing rate. The Company does not oppose Staff's recommendation No. 4 to include expansion rate customers in the RDM, with certain exceptions. EnergyNorth disagrees with Staff's proposals Nos. 5 and 6 to cap the annual RDM adjustment at +/- 2 percent and eliminate the mid-period adjustment.

[4] Direct Testimony of Al-Azad Iqbal ("Iqbal Testimony") dated November 30, 2017, Bates 000010.

B. Staff's Proposal to Exclude Weather Variation from the RDM

Q. Please explain why you disagree with Staff's recommendation to use weather-normalized revenues in the RDM.

A. There are four main areas of disagreement with Staff's direct testimony. First, I disagree that decoupling should be limited solely to company-funded conservation programs. Second, I will rebut the assertion that that the Company's proposal "also eliminates all risk except the risk of management efficiency." Third, I will clarify and explain that the clear majority of RDMs across the country include weather variation in the RDM true-up calculation, either by using actual revenues per customer or a separately billed Weather Normalization Adjustment ("WNA"). Fourth, I add additional context to Staff's interpretations of past Commission guidance regarding decoupling.

1. Scope of the Company's RDM proposal

Q. Do you agree with Staff's assertion that the Company's proposal "is well beyond the efficiency and conservation related sales reductions"?

A. No, I do not. Staff stated, "The Company's proposal adjusts for all impacts on revenue (e.g., the economy, energy efficiency, weather etc.) which is well beyond the efficiency and conservation related sales reductions."[5] Staff's proposal limits reconciling changes in sales related to utility-funded conservation programs only, and ignores other energy efficiency and conservation actions customers and other stakeholders take to reduce gas

[5] Id., Bates 000011, lines 16 through 16.

consumption. In my direct testimony I cite five contributors to declining use per customer:

1) Utility-sponsored Energy Efficiency ("EE")/Demand-Side Management programs;
2) Customer self-funded conservation measures;
3) Improvements in appliance efficiencies and building code requirements;
4) Consumer responsiveness to increases in natural gas prices and/other economic and demographic factors; and
5) A warmer normal weather trend.[6]

Referring to the above list, items 1), 2), and 3) are unambiguously directly related to energy efficiency, and 4) customer price responsiveness, is (short term reversible) conservation-related when customers are responding to price increases. Item 5) is a clear trend that reduces customer usage. Staff's recommendations focus entirely on contributor 1).

Q. Does the OCA support a decoupling mechanism that encompasses all contributors to the variation in sales?

A. Yes. Although the testimony of Dr. Johnson recommended two modifications to the Company's proposal that I will address later in this testimony, he did not propose to eliminate the impact of weather, or any other variable that contributes to the consumption of gas volumes. In his testimony Dr. Johnson wrote:

---

6 Direct Testimony of Gregg H. Therrien ("Therrien Testimony"), Bates 305.

> **Q. Is the proposed decoupling mechanism an improvement over the existing LRAM?**
> A. Yes. It does a better job of removing the disincentive for EnergyNorth to encourage energy conservation, while eliminating the bias in favor of programs and initiatives included in the LRAM.[7]

Dr. Johnson also asserted that:

> Decoupling achieves a broader, more fundamental shift in incentives, because revenues become largely impervious to improvements in energy efficiency – including improvements resulting from tightened building codes, increased appliance standards, technology improvements, heightened awareness of greenhouse gas emissions, and other factors. This broader scope is significant, because EnergyNorth can potentially influence the decisions by customers and the companies that construct new buildings concerning what insulation they install, what appliances they purchase, and what type of energy they use. Currently, EnergyNorth has an incentive to steer customers into the programs and initiatives included in the LRAM, rather than finding other ways to reduce their energy usage that are not tied to those specific programs.[8]

Dr. Johnson's assertions are instructive as to how the Company, together with supportive Commission policy, can enhance energy efficiency. In this regard, full decoupling is the means to this broader scope without penalizing the Company.

---

7 Direct Testimony of Ben Johnson, PH.D. ("Johnson Testimony"), dated November 30, 2017, Bates 9, line 20 through Bates 10, line 1.

8 Id., Bates 000007, lines 7-17.

2. Business Risks

Q. Please describe Staff's assertions concerning the effect that an RDM would have on EnergyNorth's business risks.

A. Staff stated, "The Commission was also concerned with the potential for risk shifting via decoupling. The Company's proposal adjusts for all impacts on revenue (e.g., the economy, energy efficiency, weather, etc.) which is well beyond the efficiency and conservation related sales reductions. It also eliminates *all risk* except the risk of management efficiency."[9] *(Emphasis added)*.

Q. Does decoupling eliminate all risks except "management efficiency"?

A. No, it does not. Decoupling does not eliminate other, very real risks that gas utilities face, such as increased competition, regulatory risks, economic risks that affect the cost to serve (e.g., inflation), etc. These other exogenous risks, which are beyond the reasonable definition of "management efficiency," are not addressed through decoupling.

3. Weather Normalization and RDMs

Q. Is it common for RDMs to exclude weather from the calculation?

A. No. In fact, only three of the sixty-seven utilities with an RDM in the United States exclude the impact of weather in their RDM calculation. These include utilities in Colorado, Washington State, and Wyoming. Twenty utilities have separate WNA rate

9 Iqbal Testimony, Bates 000011 lines 13-17.

adjustments that complement their RDM, an alternative to including the impact of weather explicitly in the RDM. This is shown here:

Table 1: RDM Calculation Methodologies in the U.S.

Calculation:	Revenue Per Customer (RPC)			Total Revenue			PBR	
State	RDM using Actual Weather	RDM using normal weather and a separate WNA	RDM using normal weather and no WNA	RDM using Actual Weather	RDM using normal weather and a separate WNA	RDM using normal weather and no WNA	PBR (Includes Weather)	Total
AR	1				2			3
AZ		1						1
CA				1			3	4
CO			1					1
CT				1				1
GA							1	1
ID				1				1
IL	2			1				3
IN				2	1			3
LA					1			1
MA	6							6
MD	4			1				5
MI	1							1
MN	1			1				2
MS					1			1
NC	1			1				2
NJ		2						2
NV	1							1
NY	2	7		1	1			11
OR	1	1		1				3
RI	1							1
SC							1	1
TN		1						1
UT		1						1
VA	3							3
VT							1	1
WA	2					1		3
WI	1							1
WY		1	1					2
Grand Total	27	14	2	11	6	1	6	67

As this table shows, almost all LDCs with an RDM also have a mechanism to reconcile for weather. Including a weather reconciliation in the RDM is the norm, not the exception.

4. Past Commission Orders

Q. What is Staff's interpretation of Commission policy regarding decoupling?

A. Staff's interpretation of Commission policy is that a limited decoupling mechanism is the Commission's preferred approach. Staff relied primarily on Docket No. DE 07-064, which pre-dates the EERS Settlement by nearly a decade, and was opened specifically to investigate energy efficiency rate mechanisms.[10] Although Docket No. DE 07-064 did discuss decoupling in the context of overall rate design, and contains high-level guidance regarding cost causation and the impact of rate design changes on certain rate classes,[11] the Order Resolving the Investigation is not a prescriptive document for implementing decoupling. Rather, the investigation set out to answer the following four questions:

1) whether existing rate treatment poses an obstacle to investment in energy efficiency;
2) whether a different rate treatment would promote such investment;
3) whether these issues should be pursued further in this docket, through utility-specific rate cases, as part of a rulemaking, or through some other procedure; and
4) whether decoupling constitutes an alternative form of regulation under RSA 374:3-a. Order No. 24,934 at 4 (January 16, 2009) ("the 2009 Order").

In the 2009 Order, the Commission concluded, "We find, therefore, that the best approach to implementing such rate mechanisms is on a company-by-company basis in the context

10 "On May 14, 2007, an order of notice was issued commencing this investigation into the merits of instituting, for electric utilities, appropriate rate mechanisms that would have the effect of removing obstacles to, and encouraging investment in, energy efficiency." Order No. 24,934 (January 16, 2009).

11 Iqbal Testimony, at Bates 000008.

of an examination of company specific costs and revenues inasmuch as each utility has a unique service territory and customer mix as well as company specific operating costs and rate base investment." 2009 Order at 19. Nowhere in that Order does the Commission state its preferred decoupling model. On pages 20 through 22 of the 2009 Order, the Commission did discuss "Rate Mechanism Options" including "Reconciling Rate Adjustments" (decoupling), but did not prescribe, or even suggest, that one option is superior to another. Rather, the Order states "*Regardless of the model used*, it would be appropriate to propose revenue decoupling in the context of a rate case in order to avoid single-issue ratemaking." (Emphasis added.)

Q. Did the EERS Settlement address decoupling?

A. Yes, in part. My Direct Testimony regarding decoupling described the key agreements regarding energy efficiency programs and related rate mechanisms for utilities in New Hampshire:

1) Extends the Core programs;

2) Requires implementation of a LRAM, commencing January 1, 2017 (capped at 110% of planned annual savings);

3) Contemplates the subsequent implementation of a decoupling mechanism to replace the LRAM;

4) Will implement the EERS commencing January 1, 2018;

5) Retains the Performance Incentive, with modifications;

6) Increases the low-income share of the overall energy efficiency budget; and

7) Includes other legal provisions.

The Commission approved the Settlement Agreement in Order No. 25,932 (August 2, 2016).[12]

Q. Please summarize the sections of the EERS Settlement that pertain to LRAM and decoupling.

A. Section II B. of the EERS Settlement, "Lost Revenue Adjustment Mechanism and Decoupling" codified the agreement among the Settling Parties as to when the LRAM must be implemented and when utilities may, in the context of a general rate case, propose a decoupling mechanism. The calculation of the LRAM is very explicit in the EERS Settlement – covering approximately two pages of the document. In contrast, decoupling is discussed in more general terms and consumes only one-half page in the EERS Settlement.

The EERS Settlement states:

> The Settling Parties agree that the LRAM for each utility will cease when a new decoupling mechanism, or another mechanism as an alternative to the LRAM, is implemented. The Settling Parties further agree that each of the Utilities shall seek approval of a new decoupling mechanism, or another mechanism as an alternative to the LRAM, in its next distribution rate case following the first triennium of the EERS, 20l8-2020. This provision does not, and is not intended to, prevent or preclude any of the Utilities from

12 Therrien Testimony, Bates 299.

> seeking approval of such mechanism prior to the end of the first triennium, but the Settling Parties acknowledge and agree that any utility seeking such approval shall do so in the context of a distribution rate case, consistent with the Commission's guidance in Order No. 24,934 (January 16, 2009). The Settling Parties agree that the Commission's approval of the Settlement Agreement does not in any way restrict the Commission from investigating or implementing decoupling, or another mechanism as an alternative to the LRAM, at any time.[13]

Q. Does the EERS Settlement address weather normalization or any aspect of how an RDM should be constructed?

A. No. The above excerpt is the entire content regarding decoupling in the EERS Settlement.

Q. Did the Commission approve the EERS Settlement?

A. Yes. The Commission approved the EERS Settlement in Order 25,932 (August 2, 2016) (the "2016 Order"). In the 2016 Order, the Commission first required utilities to implement an LRAM effective January 1, 2017, and recognized that some of the Settling Parties preferred decoupling. The 2016 Order states:

> We note that our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism, and that the Joint Utilities (except NHEC) are required to seek approval of a decoupling or other lost-revenue recovery mechanism *as an alternate to the LRAM* in their first distribution rate cases after the first EERS triennium, if not before (*emphasis added).* [14]

[13] EERS Settlement Agreement, page 5-6.
[14] Order No. 25,932 (August 2, 2016), at 60.

Q. What can be concluded from the Commission's 2009 Order and 2016 Order regarding decoupling?

A. The 2016 Order clearly articulated the Commission's requirement for utilities to seek approval of something other than an LRAM. As with the 2009 Order, the Commission did not prescribe, endorse, or articulate any specific decoupling methodology, only that utilities should propose an RDM in the context of a general rate case.

C. Staff's remaining five recommended changes to the Company's proposed RDM

1. Staff Recommendations 2, 3, and 4.

Q. Please describe the second and third Staff recommendations to perform the RDM calculation at the rate class level, and the Company's response to Staff recommendations.

A. Staff's second recommendation is that the RDM adjustment should be performed at the rate class level (instead of the proposed RDM Rate Groups).[15] Staff's third recommendation is that expected RDM revenues should be calculated at the individual rate class level, not at combined rate class level.

The Company does not object to calculating the RDM adjustment (accrual) at the rate class level. Further, our understanding of Staff's testimony is that the resulting variances, at the rate class level, will be summed for the Commercial and Industrial ("C&I") classes for purposes of determining the RDM rate adjustment to be applied to customers' bills. Staff did not provide a recommendation as to whether Residential Non-Heating customers

---

15 Therrien Testimony, Table 8: RDM Customer Groups, Bates 320.

should receive a separate billing rate from Residential Heating customers under his proposed modification. Staff did, however, tie its recommendation to energy efficiency program "sectors," which combines Residential Non-Heating and Heating together. Using that definition, the Company assumes Staff is suggesting only two separate RDM billing adjustments – one for Residential and one for C&I. Assuming my understanding is correct, the Company does not object to these two recommended changes.

Q. Please explain Staff's fourth recommended change to the Company's RDM Proposal.

A. Staff recommended that customers receiving service under the MEP tariffs also be subject to decoupling. Staff believes RPC for MEP customers should be included in the rate class revenue calculation after the MEP premium is separated.[16]

Q. Does the Company object to this recommendation?

A. No, it does not provided that the RDM rate for MEP customer is the same as the corresponding rate for all other customers in the class.

2. Staff Recommendations 5 and 6.

Q. Does the Company agree with Staff's fifth recommendation to change the +/- 5% cap to a +/- 2% cap?

A. No, the Company's proposed +/- 5% cap should not be changed. The Company's proposal to include weather in the RDM requires a larger cap bandwidth than +/- 2%.

---

[16] Iqbal Testimony, Bates 000001, lines 18-19.

Otherwise, large deferrals may occur resulting in a larger collection or refund in a subsequent period.

Q. Does the Company agree with the elimination of the mid-term adjustment?

A. No, because the Company's proposal includes the effects of weather. Staff's rationale for proposing elimination of the bi-annual adjustments in favor of a singular annual adjustment is tied to its recommendation to exclude weather from the RDM calculation. The Company continues to advocate for weather-related variances be included in the RDM. Therefore, we continue to advocate for mid-term adjustments.

D. <u>Energy Efficiency ("EE") Performance Goals</u>

Q. Please summarize Staff's recommendation regarding EE goals and decoupling.

A. Staff introduced another proposed decoupling restriction tied to obtaining EE goals. Staff proposed that, "If the Company does not meet its EE goals, there should be some restriction in decoupling adjustment because the logical conclusion is that the decoupling adjustment was attributed to something other than EE."[17] To summarize, Staff recommended that if the RDM calculation yields a charge in excess of the cap (presumably their 2% recommended cap) and EnergyNorth does not meet its EE goals, then "the Company would be required to demonstrate that its EE efforts were the primary factor in reducing its energy sales in order for any amount above the decoupling cap to be

[17] Iqbal Testimony, Bates 000013, lines 10-12.

carried forward for recovery in a subsequent year."[18] A credit calculation would not be subject to such a review.

Q. Do you agree with Staff's recommended asymmetrical cap restriction?

A. No, I do not. Limiting the decoupling calculation to exclude any sales variation "other than EE" will penalize the Company for expanding its EE efforts beyond company-funded programs. I have presented in my Direct Testimony, and in this rebuttal testimony (Section III. B. above), that decoupling is intended to completely sever the link between utility revenues and sales units. Otherwise, the signal to the Company is something less than desired – because sales volumes will still matter.

E. The Company's response to the OCA's proposed RDM modifications

1. Introduction

Q. Please summarize the major points of OCA Witness Dr. Johnson regarding decoupling.

A. Dr. Johnson, on behalf of the OCA, proposes two modifications to the Company's RDM proposal. First, he proposes a "real time" decoupling adjustment for the weather-related portion only, and 2) recommends that the RDM be calculated on a "Total Revenues" basis as opposed to RPC.

---

[18] Ibid, lines 14-17.

Q. Did the OCA make other assertions regarding decoupling?

A. Yes, he did. I will address, and rebut where appropriate, assertions made by the OCA regarding decoupling's association with Company earnings, rate base, and capital investments and depreciation. I will also address the OCA recommendation to disallow potential Computer Information System ("CIS") modification costs from rates.

2. OCA's recommended RDM changes

a. "real-time" adjustments

Q. Please summarize OCA's first recommendation regarding a "real-time" decoupling adjustment.

A. The OCA recommended that the Company separate the weather-related portion of the RDM from the remainder of the calculation. Specifically, the OCA called for a customer-by-customer calculation of the impact of weather, and bill that amount (based on the customer's actual volumetric delivery charge unit rate) in the month in which the weather variance occurred. In doing so, the OCA submitted that "it will help smooth out bill fluctuations, making cash flows smoother and more predictable for both the Company and its customers."[19] The OCA also provided examples of how this real-time adjustment would work, under both colder-than-normal and warmer-than-normal weather conditions, making the point that the real-time adjustment will match the variation in weather and provide synchronized, real-time revenue stabilization to customers and the Company.[20]

---

19 Johnson Testimony, Bates 16, lines 9-11.
20 Id., Bates 16-18.

Q. How would the portion of the decoupling adjustment that is not weather-related be treated?

A. The calculation of the RDM would be calculated essentially the same as proposed by the Company (I will address the OCA's "Total Revenue" recommendation later in this testimony). The total difference between Actual and Target revenues will be refunded or collected in a subsequent period. The OCA noted that this adjustment would likely be considerably smaller than an RDM that does not adjust for the weather component real-time.[21]

Q. What reservations does the Company have regarding separating the weather component of the RDM on a real-time basis?

A. "Real time" weather adjustment, referred to as a Weather Normalization Adjustment or "WNA," requires that the dollar impact of the difference between actual and normal usage be calculated for each customer bill, at the time the bill is rendered. This requires extensive programming in the billing system, and significant additional training of call center personnel charged with explaining the WNA to customers.

The OCA stated that "customers are more likely to understand and accept the mechanism if the portion that deals with weather-related fluctuations is separated from the portion that deals with energy conservation and other factors influencing usage."[22] Although I agree that matching the weather-related portion of the mechanism with the customer's bill is a

[21] Id., Bates 15.
[22] Id., Bates 19, lines 2-4.

reasonable concept, I am not convinced that it is easier to explain than an annual true-up. For example, the Company's proposed RDM results in a single billing rate adjustment to be applied each month of the applicable season. It is easy to explain that a charge occurs because last winter's weather was warmer than normal. The issue I have with real-time application is that the formula is complex and difficult to explain, and contrary to the OCA's assertions, I have experienced first-hand the difficulty in explaining this adjustment on a customer's bill. This difficulty stems from the following factors:

1) EnergyNorth has twenty billing cycles in a billing month, and they span approximately sixty days (i.e., cycle 1 customers are billed from the beginning of the prior month to the beginning of the current month, while the last billing cycle closely matches the calendar month in which it is billed). Call Center employees will need to consult the actual and normal degree days for the applicable billing cycle to explain the variances.
2) Call Center representatives will also need to understand a complex formula used to derive the actual charge that is on each customer's bill. This includes understanding base usage, heat usage, degree days, and the blended volumetric rate applied to the usage adjustment.
3) If there was a reason for the customer's bill to be adjusted (e.g., cancelled then rebilled), the complexity of the bill makes auditing of the WNA charge extremely difficult.

4) From a rate administration perspective, rate changes result in a month of pro-rated bills. The WNA adds complexity to the necessary audit of distribution rate changes.

5) Reporting requirements (both to internal utility management and to state commissions) is likely to increase and add complexity.

In contrast, the Company's proposed RDM is easy to understand, calculate, and audit, and should have minimal reporting requirements.

Q. Please describe the Company's concerns with the OCA's proposed RDM.

A. The concern with the OCA's proposal is that it is unnecessarily complex. Forty-four of the sixty-seven U.S. companies with an RDM use the more straightforward approach to including weather variances that the Company has proposed. Although twenty utilities do employ the combination of a WNA and decoupling, it is likely the result of already having a WNA in place prior to introducing decoupling. Despite its complexity, it is still superior compared to an RDM that excludes the impact of weather.

Q. Do the above concerns imply that the Company is unwilling to employ RDM with a real-time adjustment?

A. No. The OCA's proposed real-time RDM component does have benefits for both customers and the Company, and, most importantly, recognizes that all contributors to sales variation impact the efficacy of energy conservation. A real-time RDM is superior to Staff's proposal that does not include weather variation in the calculation. The OCA's proposal is a true decoupling mechanism, and the Company appreciates the OCA's understanding of, and dedication to, an RDM that truly breaks the link between utility revenues and gas usage.

Q. If a real-time RDM were implemented, how would the Company address the difficulties that you describe above?

A. If a real-time RDM were implemented, the Company would work with both the OCA and Staff to develop communications materials for customers, and to address the administrative and reporting requirements associated with a real-time RDM.

b. "Total Revenue" RDM

Q. Please describe the OCA's proposal to utilize a "Total Revenue" approach to RDM.

A. A Total Revenue approach is exactly that – total revenues are "locked in" as a result of the Commission's final determination in the rate case and these revenues then become the "Target" revenues utilized in subsequent RDM filings, comparing Actual total revenues to this Target. The primary advantage of a Total Revenue approach lies in its simplicity and predictability. Simply put, revenues do not change year-over-year. The primary disadvantage, which the OCA recognized, is that it can be a deterrent to growth. That is why more U.S. LDCs employ an RPC decoupling mechanism rather than a Total Revenue approach. LDCs are in the business of adding new customers to the distribution system, either through conversion from an alternative fuel within its existing system footprint, or from expanding the system to reach new customers. Total Revenue RDMs do not encourage growth (and, in fact, discourage growth) because revenues received from new customer additions are in effect "refunded" to existing customers through the RDM, leaving the utility to fund growth investments without incremental revenue to support those investments.

Q. Please explain why utility retention of revenues from new customers is important.

A. Most U.S. commissions, like New Hampshire, encourage their LDCs to expand, providing greater fuel choice to the residents of their respective states. Further, regulators want to protect against existing customers subsidizing uneconomical growth. New customer revenues help cover the cost of new investments without adding pressure to seek rate relief that results from a growing rate base. If these new customer revenues are not retained, but returned to existing customers through a Total Revenue RDM, then, all else being equal, the utility will seek rate relief sooner than if those revenues were retained.

Q. Does the New Hampshire Commission encourage growth?

A. Yes, it does. The Commission has approved the Managed Expansion Program ("MEP"), which also includes separate rate schedules with premium distribution rates. These premium rates help fund more aggressive system expansion than that which could otherwise be supported through standard delivery rates. The Commission recognizes that increased sales reduces the fixed costs borne by all other customers by spreading those costs over a greater volume of sales.

Q. Are there other related comments made by the OCA regarding funding of growth investment?

A. Yes. The OCA suggests depreciation between rate cases can fund growth. He wrote:

> There is no assurance that the increase in total revenues that occur under the per-customer approach is fully needed, or that the resulting revenue growth will match any corresponding increase in the revenue requirement. It is also important to keep in mind that EnergyNorth has cash flows provided by depreciation and retained earnings that can be used to support new customer additions. If its capital additions exceed depreciation, and as a result its rate base increases (rather than decreases as depreciation accumulates), it will have the opportunity to recover the associated costs after they are reviewed and approved in a rate case.[23]

Dr. Johnson's argument that depreciation is sufficient to fund growth investments is unfounded. His argument relied on system-wide depreciation and retained earnings to fund new customer investments. I agree these are sources of funds, but only depreciation, to the extent it reduces rate base, helps alleviate revenue requirement growth. Depreciation is often used to fund *non-revenue generating capital investment*, such as reliability investments (e.g., improvements to LNG facilities, gate stations, etc.), as well as ongoing capital needs (e.g., fleet vehicles, equipment, information technology, metering, etc.).

Q. Do new customer additions require incremental investment?

A. Yes, any new customer addition to the system will require at least a service line and meter. In many cases, such as MEP projects, new main is also required to serve new customers. If the OCA's recommendation to include new customer revenues in its proposed Total Revenue RDM is implemented, then the Company will incur a shortfall in revenue

[23] Id., Bates 13, lines 4-11.

requirements associated with this new investment, which may have a dampening effect on growth.

Q. Does the OCA offer a solution to this problem?

A. Yes, in part. The OCA proposed an alternative: exclude expansion customers from the RDM.[24] This is the same solution the Company proposed in its Direct Testimony.[25] If the Commission wishes to include expansion customers in the RDM, it should consider Staff's fourth RDM recommendation, which would exclude the 30% distribution rate premium revenues from the RDM calculations, but include the remaining (base level) revenues from MED customers in the RDM calculations. However, the expansion rate is only applicable to those areas where customers could not be served under standard rates (absent a high CIAC by those customers). The OCA's proposal did not address the majority of the Company's growth, which is under standard rates. Additional revenue from that growth would still be refunded to customers through the OCA's proposed RDM.

Q. Please summarize the Company's position regarding the OCA's Total Revenue RDM approach.

A. The Total Revenue approach is flawed insofar as conflicts with Commission policy to encourage natural gas expansion. For gas utilities, retaining growth-related revenues to fund the incremental investment is critical, particularly during a concerted effort to expand the system. Additionally, RPC RDMs are more common than Total Revenue RDMs (s*ee*

---

[24] Id, Bates 14, lines 9-19.

[25] Therrien Testimony, Bates 323, line 3 through Bates 324, line 2.

Table 1). For these reasons, the Company reiterates its preference for a revenue-per-customer RDM.

3. CIS Upgrade for Real-Time RDM

Q. Please comment on the OCA's recommendation to disallow any incremental costs associated with CIS investments necessary to implement their proposed real-time decoupling proposal.

A. It is inconsistent for the OCA to advocate for disallowance of a cost that supports the OCA's real-time RDM proposal, a cost that is not necessary to implement the Company's proposal. If the OCA's real-time RDM proposal were to be approved, the related costs should be considered legitimate business expenses and allowed for recovery. The Commission Staff audits expenses and investments made by the Company as part of rate reviews. There is no need to predetermine that the CIS changes necessary to implement a real-time RDM should be disallowed prior to the project commencing.

IV. <u>RATE DESIGN</u>

A. <u>Response to Staff's Recommendations</u>

Q. Please summarize Staff's recommended head and tail block delivery rate changes.

A. Staff recommended two changes:

1) Set the rates for both head and tail block at the same level; and

2) Allocate any decoupling adjustment to the head or tail blocks based on whether it is a surcharge or refund. Refunds would be allocated to head block and surcharges

would be collected from the tail block for the residential sector and high winter use C&I customers.[26]

Q. Please explain the Company's response to Staff's first recommendation, that head and tail blocks should be equalized.

A. Staff's proposed change does not significantly impact customers' bills to warrant objection considering the Company's decoupling and fixed customer charge rate proposals.

Q. Does the Company object to Staff's second recommendation?

A. Yes. Staff proposed an asymmetrical application of the decoupling adjustment between the head and tail block volumetric delivery rates. Justification for this proposal is two-fold. First, Staff claimed that, "It will provide a proper price signal to the customers to encourage energy conservation."[27] Second, "This approach would also benefit lower consumption households that could tend to include be lower income households with smaller homes and less energy use compared to higher income households. Low use households, on average, have relatively little or no consumption in the tail block and thus would see little or no rate increase from decoupling."[28]

Staff's proposal is unfair to higher use customers that have much of their monthly usage in the tail block. Their proposal unfairly allocates RDM under recoveries to higher use

---

[26] Iqbal Testimony, Bates 000016, lines 19-22.
[27] Id., Bates 000017, lines 14-15.
[28] Id., Bates 000017, lines 15-19.

customers and unfairly allocates RDM over recoveries to lower use customers. Staff's assertion that their proposal further encourages conservation through a price signal that charges a higher rate on higher consumption is unsupported.

Q. Does Staff's proposal have the potential for under-recovery?

A. Yes. Under Staff's proposal, many low use customers would presumably not pay a decoupling charge because their usage would be low enough as to not fall into the tail block. This creates the potential for a shortfall in recovery that must be deferred until the next winter season.

Q. Does Staff's proposal alleviate concerns regarding undue rate impacts to small rate classes?

A. No. Staff argued that "This addresses the stated concern of the Commission that any decoupling proposal to change the rate design needs to consider the impact on small rate classes to ensure that such classes are not unduly impacted by such changes", and "It also reduces the volatility of gas bills for low use customers."[29] Using data from my direct testimony, the highest winter period decoupling adjustment over the past five years would have been $0.0180 per therm.[30] To put this in perspective, a Low Income Residential Heating customer on the R-4 rate using 105 therms in January has a total bill of $105.46 at current rates.[31] If decoupling were in place in January 2017, this customer would have

29 Id., Bates 000017, line 19 through Bates 000018, line 2.
30 Therrien Testimony, Bates 328, Table 10, Winter 2016-2017 rate per therm.
31 Direct Testimony of David B. Simek and Gregg H.Therrien ("Simek/Therrien Testimony"), April 28, 2017, , Attachment RATES-8, page 3 of 16 (Bates 257), line 203.

been charged an additional $1.89, which would have represented a 1.8% increase to their bill. I do not believe that a $1.89 charge would "unduly impact" low use customers or create "volatility" in their gas bills. If Staff's recommendation to eliminate the difference between head and tail block unit rates is implemented, low use customers rates would go down because current rates have a higher head block rate than the tail block. Using Staff's premise that low use customers are less likely to experience usage in the tail block, their overall bill will likely go down more than any increase from a decoupling charge.

B. <u>Response to the OCA's Recommendations</u>

Q. Please summarize your understanding of the OCA's proposed rate design.

A. The OCA seeks to reduce fixed customer charges and increase volumetric charges, particularly in the tail block.

Q. What justifications does the OCA use to rationalize reducing customer charges?

A. The OCA began its argument for lowering fixed charges not by introducing evidence to support such an action, but rather through criticizing the Company's logic for requesting increases. These criticisms include how the flow of the rate design Exhibit-5 works, which is a mathematical schedule that logically reconciles allocated class revenue requirements by first subtracting out fixed cost recovery then volumetric recovery. The OCA also makes the following criticisms and recommendations related to the Company's proposed customer charges: (1) the Company's estimate of marginal customer-related costs is flawed and therefore, the Company's proposed customer charges, which are informed by the estimated customer-related costs is also flawed; (2) greater consideration should be given to increasing volumetric rates, to advance state conservation goals, which necessarily requires lowering fixed charges; and (3) lastly, the OCA attempted to dismiss long-standing cost causation principles used in utility rate design.

Q. Are the Company's rate design workpapers biased towards increasing fixed customer charges?

A. No, the rate design workpapers are mathematical, and follow a logical sequence to prove proposed rates produce proposed revenues (i.e. "revenue proof"). The OCA asserted that "The Company made a priority to increase its customer charges (the fixed monthly rate that applies regardless of how much or how little gas the customer uses). This priority is apparent from the workpapers it used to develop the proposed rate design, and is alluded to on pages 16-17 of the joint testimony of Simek and Therrien."[32] His claim that the construct of the Company's workpapers prioritize increased customer charges is unsupported and no alternative calculation is presented.

Q. Is the Company's rate design approach consistent with past precedent?

A. Yes, the Company's recommended fixed cost rates are in line with prior proposals, which have also relied on the results of the MCS to guide its rate design recommendations. Further, as stated in the Simek/Therrien Testimony, "The proposed rates represent a balancing of the principles of appropriate rate design which include efficiency, simplicity, continuity of rates, fairness between rate classes, and corporate earning stability."[33] These

[32] Johnson Testimony, Bates 24, lines 19 – 22.
[33] Simek/Therrien Testimony, Bates 205.

are long-standing principles that have guided utility ratemaking for decades.[34] The OCA suggested that employing these principles undermines the Company's proposal to increase fixed charges, citing our direct testimony at page 17as follows:

> To determine the appropriate level of customer charges for each class, we considered: (1) the marginal customer costs resulting from the marginal cost study; (2) rate continuity; and (3) customer impacts.

In response to this stated approach the OCA stated, "The second and third items just mentioned did not support increasing the customer charges; rather, they ameliorated the extremely large increases that would be needed to move these rates all the way to the Company's estimate of marginal cost."[35] Interpreting this passage, it appears that Dr. Johnson believes that employing rate continuity and customer bill impacts undermines the Company's proposal. This is contrary to the rate design principles discussed above.

Q. Does the Company have any other comments regarding the efficacy of raising the tail block distribution rates?

A. Yes. First, the Company notes that the tail block currently represents approximately 3.3% of the total bill.[36] The commodity portion is 54.7%.[37] Raising the tail block rate will have only a minimal price signal compared to the price of the commodity, which is subject to change every month, and can change significantly. Second, using OCA's proposed rates,

---

34 *See* "Principles of Public Utility Rates", Second Edition, by James C. Bonbright, Albert L. Danielsen and David R. Kamerschen. Public Utility Reports, Inc. 1988.
35 Johnson Testimony, Bates 25, lines 7-9.
36 Using January 2016 Residential Heating (R-3) as a proxy. See Simek/Therrien Testimony Attachment RATES-8 page 2 of 16 (Bates 256), line 112/132.
37 Ibid, line 124/132.

[38] bill impacts for larger users are considerably higher compared to the Company's proposal.

Q. Has the Commission considered cost causation when designing utility rates?

A. Yes. The Commission has not only recognized, but has been progressive in recognizing cost causation and has designed rates with this important principle in mind. The OCA referred to an American Gas Association (AGA) survey that indicates that the Company's fixed customer charges are high compared to other gas utilities. This comparison should not deter the Commission from designing rates based on cost causation principles. The costs of providing utility service are largely fixed, and having a customer charge that sends the price signal that utility service is available regardless of how much gas is consumed is appropriate. The Company's Marginal Cost Study indicates Residential class customer costs in excess of $60 per month, well above the Company's proposed monthly customer charge for rates R-1 and R-3.

Q. Should public policy considerations play a role in rate design?

A. Yes. However, the rate design principles cited above should not be ignored. If the Commission wishes to move toward more volumetrically-weighted rates, it should do so only after assessing the impact on the full range of customers' bills, and respecting the other long-standing rate design principles of rate gradualism and simplicity.

---

[38] Johnson Testimony, Bates 107.

V. CHANGES TO THE LOW-INCOME PROGRAM

Q. Please summarize your understanding of Staff's proposed modifications to the Residential Low-Income Assistance Program ("RLIAP").

A. Staff has proposed to modify the existing RLIAP in two phases. First, the RLIAP is proposed to be reduced from a 60% reduction in delivery-only charges to 25% of total projected gas costs. Second, in year 2 the rate would decline to 20% of projected gas costs. As is currently done, the proposed RLIAP rate should be included in the LDAC rate contained in EnergyNorth's winter COG filing, and the approved LDAC rate would be effective for November 1 through October 31, with savings to be calculated on the projected total bill for an average residential heating customer for the 12 months commencing November 1 of that year.[39] Although not specifically addressed, the Company assumes that base delivery rates in the instant case would continue to include an adjustment to the firm delivery rate classes for the projected rate year RLIAP projected dollar amount, and any differences reconciled through the COG annual filing and billed through the LDAC.

Q. Does the Company agree with this proposal?

A. The Company does not take a position with this proposal. However, the Company questions the timing of this proposal and use of the instant proceeding to review it.

[39] Direct Testimony of Stephen P. Frink, November 30, 2017 Bates 27.

Q. Please explain.

A. The Company believes that this topic is best adjudicated through a generic proceeding, which would continue past precedent established in the original pilot program in Docket No. 05-076, see Order No. 24,508 (September 1, 2005), and subsequent program revisions in Docket No. DG 06-120, see Order No. 24,669 (September 22, 2006). In addition, Staff's proposal implicates other rate components that are not part of this rate case. Further, this issue was not included in the Commission's Order of Notice in this proceeding[40] which may have precluded other interested entities from intervening in this case. For these reasons, the Company respectfully recommends that the Commission open a separate generic proceeding if this proposal is going to be considered.

Q. How would rejecting this proposal change the instant case?

A. The Company's filing in the instant case would not be changed. Further, any changes that may arise from a generic RLIAP proceeding could be implemented through the annual COG filing, and rates adjusted through the LDAC. It is not necessary to implement a change in the RLIAP in the context of a general rate case.

[40] Order No. 26,015 (May 8, 2017) "Order Suspending Proposed Tariff and Scheduling Prehearing Conference and Temporary Rate Hearing".

VI. SUMMARY

Q. Please summarize this rebuttal testimony.

A. EnergyNorth appreciates the inputs received from Staff's witness Mr. Iqbal and OCA witness Dr. Johnson regarding decoupling and rate design. However, some aspects of their respective proposals should be rejected. Specifically:

1) **Staff's recommendation to weather normalize sales prior to performing the RDM adjustment should be rejected.** Staff's decoupling proposal is nothing more than a continuation of the LRAM and does not sever the link between Company sales volumes and revenues, which undermines the potential for greater energy efficiency savings present in the Company's and in the OCA's decoupling proposals.

2) **The Company agrees with the OCA's proposal for a "real-time" RDM, but disagrees with calculating decoupling on a Total Revenue basis.** EnergyNorth is a natural gas utility in growth mode, and the incremental revenues from new customer additions should be retained between rate cases to fund growth investments. Any incremental computer enhancement costs to implement this proposal should not be rejected, as recommended by the OCA..

3) **Staff and the OCA's inclining block rate proposals should be rejected.** The Commission's long-standing practice of designing customer rates based on cost causation should not be discarded as a result of implementing the RDM. As detailed above, gas commodity charges represent the largest component of the bill

and send the most impactful price signal. Further, the Company's proposed fixed customer charges should be approved, as supported through the MCS.

4) Staff's proposal to change the RLIAP should be addressed in a properly noticed generic proceeding.

Q. Does this complete your testimony?

A. Yes, it does.