STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 19-161

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

DIRECT TESTIMONY

OF

STEVEN E. MULLEN

November 27, 2019

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I. <u>INTRODUCTION AND BACKGROUND</u>

Q. Please state your name and business address.

A. My name is Steven E. Mullen. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. By whom are you employed and in what capacity?

A. I am employed by Liberty Utilities Service Corp. ("Liberty") as Director, Rates and Regulatory Affairs. I am responsible for rates and regulatory affairs for Liberty Utilities (EnergyNorth Natural Gas) Corp. ("EnergyNorth" or "the Company") and Liberty Utilities (Granite State Electric) Corp. ("Granite State") in New Hampshire, Liberty Utilities (Peach State Natural Gas) Corp. in Georgia, and Liberty Utilities (St. Lawrence Gas) Corp. in New York.

Q. Please state your professional experience and educational background.

A. In 2014, I was hired by Liberty as the Manager, Rates and Regulatory, and was promoted to Senior Manager in August 2017 and to my current position of Director in July 2018. In addition to managing the Rates and Regulatory Affairs department, I am responsible for the development of regulatory strategy, interacting with regulators and other parties on behalf of Liberty, review and preparation of testimony and other aspects of regulatory filings, and internal approval of rate changes for EnergyNorth and Granite State, among other duties.

From 1996 through 2014, I was employed by the New Hampshire Public Utilities Commission ("Commission") in various roles. Through 2008, I held positions first as a

PUC Examiner, then as a Utility Analyst III and Utility Analyst IV. In those roles, I had a variety of responsibilities that included field audits of regulated utilities' books and records in the electric, telecommunications, water, sewer, and gas industries, rate of return analysis, review of a wide variety of utility filings, and presenting testimony before the Commission. In 2008, I was promoted to Assistant Director of the Electric Division. Working with the Electric Division Director, I was responsible for the day-to-day management of the Electric Division, including decisions on matters of policy. In addition, I evaluated and made recommendations concerning rate, financing, accounting, and other general industry filings. In my roles at the Commission, I represented Commission Staff in meetings with utility officials, outside attorneys, accountants, and consultants relative to the Commission's policies, procedures, Uniform System of Accounts, rate cases, financing, and other industry and regulatory matters. From 1989 through 1996, I was employed as an accountant with Chester C. Raymond, Public Accountant, in Manchester, New Hampshire. My duties involved preparation of financial statements and tax returns, as well as participation in year-end engagements.

I graduated from Plymouth State College with a Bachelor of Science degree in Accounting in 1989. I attended the NARUC Annual Regulatory Studies Program at Michigan State University in 1997. In 1999, I attended the Eastern Utility Rate School sponsored by Florida State University. I am a Certified Public Accountant and have obtained numerous continuing education credits in accounting, auditing, tax, finance, and utility related courses.

Q. On whose behalf are you testifying today?

A. I am testifying on behalf of EnergyNorth.

Q. What is the purpose of your testimony?

A. My testimony provides support for EnergyNorth's request for approval of step adjustments to recover the revenue requirement associated with non-growth related capital additions placed in service during years following the test year. Such step adjustments should also include a provision for increases in property taxes that are beyond the Company's control. In addition, I provide testimony concerning certain follow-up matters from EnergyNorth's prior rate case, Docket No. DG 17-048, as well as Docket No. DG 15-362, the docket wherein EnergyNorth received approval to expand its franchise area to the towns of Pelham and Windham, New Hampshire. Finally, I describe some of the factors that led the Company to accelerate its rate case filing to several months ahead of what had previously been planned.

II. REQUEST FOR STEP ADJUSTMENTS

Q. Please describe how the current regulatory structure for EnergyNorth impacts its earnings during the time that takes place between rate cases.

A. Since Liberty Utilities' acquisition of EnergyNorth in mid-2012, EnergyNorth has filed a distribution rate case every three years or so; in 2014, 2017, and now in 2019. The prior two rate cases resulted in permanent rate increases based on historic test years, accompanied by step increases for plant placed in service during the year following the test year. In addition, EnergyNorth has annually been allowed to begin recovery of investments made as part of its Cast Iron/Bare Steel Replacement Program ("CIBS"), although that annual recovery will be ending following the March 31, 2020, end of the current CIBS year, based on a decision by the Commission in Docket No. DG 19-054. Investments made after 2017 that were outside of the CIBS program have not been subject to recovery.

Q. What is the largest source of downward pressure on a utility's earnings between rate cases?

A. The largest negative impact on a utility's earnings between rate cases is the regulatory lag between the time capital investments are made and the beginning of the recovery of the revenue requirement associated with those capital investments, particularly when those investments are considered non-revenue producing or non-growth related. That revenue requirement includes a return on and of (a/k/a depreciation expense) the investment as well as associated costs, such as property taxes.

Q. Please demonstrate the impact of regulatory lag on a utility's earnings.

A. This can best be demonstrated by way of example. Assume a utility places $20,000,000 of non-growth related capital investments into service in a year with no mechanism for rate recovery related to those investments. As a rule of thumb, the revenue requirement for utility capital investments can be roughly estimated by multiplying the capital investments by 15 percent, which provides for such items as depreciation, property taxes, and the impact of deferred taxes. For that $20,000,000 of non-growth related capital investments, the associated revenue requirement would be $3,000,000. So all else being equal, those investments in a utility's plant and equipment would reduce earnings by $3,000,000. That reduction to earnings occurs each year there is no method for rate recovery, i.e. the years between test years. This is one of the primary reasons why utilities that are investing in their system and replacing existing infrastructure need to file frequent rate cases. Putting that into perspective, as further described in the joint testimony of Shawn Furey, Brian Frost, and Heather Tebbetts, EnergyNorth has made significant capital investments which have been placed in service during 2018 and through June 30, 2019, for which there has been no cost recovery, and that is a primary reason for the filing of this request for an increase in distribution revenues.

Q. You mentioned property taxes as one of the cost items included in the revenue requirement associated with new plant investments. Have property taxes increased on previously existing plant investments?

A. Yes. Property taxes are the primary funding source for municipalities' budgets. For many municipalities, utility property comprises a large portion of the towns' tax base and is a very significant funding source for the State of New Hampshire. So even if no new capital investments are made, utilities often see their property tax bills increase.

Q. Have EnergyNorth's property taxes increased since its last rate case?

A. Yes. That case, Docket No. DG 17-048, had a 2016 test year. Property tax expense in that rate case was $9.3 million. For the test year in this case, the twelve months ended June 30, 2019, the total property tax expense was $11.8 million, an increase of $2.5 million, or 27 percent.

Q. Was EnergyNorth granted any step adjustments for plant investments placed in service after the last rate case that provided recovery for additional property taxes?

A. Yes. As part of Docket No. DG 17-048, the Commission approved a step adjustment for plant placed in service during calendar year 2017. In addition, the Company was allowed annual adjustments related to CIBS plant placed in service through March 31, 2019. However, the total amount of property tax recovery provided in those rate adjustments totaled approximately $700,000, leaving an increase of approximately $1.8 million for which there has not been any recovery to date. As compared to the amount of the Company's request in this proceeding for a temporary distribution revenue increase, property taxes alone account for a significant portion of the earnings shortfall.

Q. Given your comments above, what is the Company requesting?

A. As explained above, plant investments placed in service in the years outside of test years, particularly non-growth related capital investments, have a significant impact on EnergyNorth's earnings. Another significant cost pressure comes from property taxes, which are beyond the Company's control. While these costs are certainly not new in the overall regulated utility area, they end up causing frequent filings of distribution rate cases, which result in a significant burden not only from the Company's perspective, but also with respect to the time and effort required by the Commission, its Staff, the Office of Consumer Advocate ("OCA"), and other potential parties. With each rate case comes hundreds of thousands of dollars of rate case expenses incurred by Staff and all parties to prepare, review, and prosecute those cases. Such rate case expenses ultimately end up being paid by EnergyNorth's customers. Thus, the Company would like to explore with

Staff and the OCA ways to lengthen the time between rate cases, while providing a reasonable opportunity for the Company to earn a reasonable rate of return. A multi-year plan that includes a provision for step adjustments related to plant investments, along with addressing changes in property taxes, would be a step in the right direction. This would allow the Company to focus on operating the business while also reducing rate case expenses being incurred on a frequent basis. In addition, the Company, Staff, and the OCA could devote more time and attention to exploring and planning for the future of the natural gas industry.

Q. Have there been any other developments related to property taxes that would support approval for a rate mechanism that includes property taxes?

A. Yes. On June 21, 2019, HB 700, which established a methodology for valuing utility distribution assets for property tax purposes, was signed into law. Part of that law established a five-year phase-in period to fully transition the property tax valuation of utility distribution assets to the required methodology. The initial property tax year of the phase-in period is the tax year effective April 1, 2020. The law also requires the Commission to establish by order a rate recovery mechanism for the property taxes incurred by a public utility. Thus, the Company's proposal is consistent with the recent law.

III. FOLLOW-UP ITEMS FROM PRIOR DOCKETS

Q. Please describe the follow-up information being provided with respect to Docket No. DG 15-362.

A. As discussed in that docket, the Company is serving customers in Pelham via a newly constructed take station on the Concord Lateral that is owned by Tennessee Gas Pipeline. Customers in Pelham are served under Managed Expansion Area rates in order to help pay of the cost of the take station. In DG 15-362, the Commission approved a settlement agreement that, in part, included a "risk sharing" mechanism whereby, as applicable to this rate case filing, the Company is required to prepare a DCF analysis that compares the revenue requirement of the take station with the anticipated annual revenue from new Pelham customers. If there is a shortage in the average anticipated annual revenue over a three-year period following the date of implementation of permanent rates as compared to the average annual revenue requirement over the same three-year period, the Company is required to absorb one-half of that shortfall.

Q. When was the Pelham take station placed into service?

A. It was placed into service on January 29, 2018.

Q. What is the proposed implementation date for permanent rates?

A. November 1, 2020.

Q. Has the required analysis been prepared?

A. Yes. Attachment SEM-1, page 1 of 2, contains the necessary analysis. As shown in the attachment, the calculated average annual shortfall is approximately $168,000, with one-half of that amount being approximately $84,000.

Q. Will this information be updated as the case proceeds?

A. Yes. It is expected that during the course of this proceeding additional sales opportunities will materialize, thus altering the results of the analysis.

Q. Have the preliminary results of the analysis been incorporated into the overall revenue requirement schedules?

A. Not at this time. As the revenue requirement testimony was being put together I was awaiting updated information concerning one large industrial customer. Rather than delay the completion of the overall revenue requirement analysis, that analysis was completed without inclusion of this Pelham-related adjustment. However, given the relatively small amount of the adjustment as compared to the total revenue requirement and the fact that it will be subject to revision as the case progresses, it would not have a material effect on the proposed overall revenue requirement being sought in this case. The final results of the analysis, however, will be taken into account as part of the overall resolution of this case.

Q. How does the information related to the large industrial customer impact the analysis?

A. That customer has an estimated annual margin of $63,107. When included in the analysis, as shown in Attachment SEM-1, page 2 of 2, it reduces the overall adjustment by approximately $31,500 to approximately $52,000.

Q. What are the items from Docket No. DG 17-048 for which you are providing follow-up information?

A. The items I will discuss are: i) the status of the amortization of the depreciation reserve deficiency that was determined in that case; and ii) various items with respect to the topic of decoupling.

Q. What was required as part of the Commission's Order No. 26,122 in DG 17-048?

A. In that docket, a fairly large depreciation reserve deficiency of a little over $9.9 million was determined to be amortized over a six-year period. As part of its order, the Commission adopted the Company's position that a re-examination of the reserve variance in EnergyNorth's next rate case, rather than performing a full depreciation study, should be performed.

Q. Has that analysis been performed?

A. Yes. The Company engaged the services of Management Applications Consulting, Inc., the same consulting firm that prepared the depreciation study in DG 17-048, in order to leverage the consultant's knowledge of the proceeding as well as its existing database of Company plant information. However, due to some unexpected delays in the contracting process, the analysis was not yet in its final form at the time this testimony was being submitted. Once the analysis has been finalized, the results will be incorporated into this case.

Q. What are the decoupling items that you are addressing?

A. In Order No. 26,122, the Commission, as part of its approval of a decoupling mechanism, required EnergyNorth to file the following information in its next rate case:

1) the amount of revenue collected or passed back through this mechanism, by year;
2) an account of any measurable impacts decoupling had on Liberty's utility sponsored energy efficiency programs;
3) a detailed list of all efforts the Company made to promote its own energy efficiency programs, and to promote other energy efficiency measures such as lobbying for stricter building/energy codes;
4) an account of efforts taken to educate builders about energy efficiency;
5) a detailed list of meetings with state and local officials and associations to promote energy efficiency;
6) customer feedback resulting from decoupling as implemented through the rate design; and
7) any changes in the Company's credit rating.

In addition to those items, the Commission required that the Company demonstrate that decoupling has allowed the Company to "remain an effective champion of energy efficiency" and has unlocked its "ability to enthusiastically support energy efficiency policy goals."

Q. Please discuss each of the above items.

A. Revenue collected or passed back to customers pursuant to the decoupling mechanism can happen one of two ways. First, through the operation of the Normal Weather

Adjustment ("NWA") that appears on each customer's bill each month during the November through April winter period, a refund or charge is determined based on the difference between actual degree days over the billing period versus the "normal" heating degree days over the same historic period. Since the implementation of decoupling effective November 1, 2018, the total revenue passed back to customers for the NWA through the end of October 2019[1] was $241,707, with the yearly totals as follows:

Total 2018	**$ (995,661.50)**
Total 2019	**$ 753,954.10**
Grand Total	**$ (241,707.40)**

The second method by which revenue can be either collected or passed back to customers is through the Revenue Decoupling Adjustment Factor ("RDAF"). The RDAF was one of the subjects of a recent docket, DG 19-145, in which the Company's Cost of Gas as well as its Local Delivery Adjustment Charge ("LDAC") were reviewed. The RDAF is one of the components of the LDAC. The RDAF provides an annual reconciliation of allowed revenues versus actual revenues, and beginning November 1, 2019, customers began receiving a credit of approximately $7 million, which is being returned over a twelve-month period. Given that the credit only recently began being provided to customers, there is no monthly information available at this time.

Regarding item 2), it is premature at this time to determine any measurable impacts that the existence of decoupling has had on the Company's energy efficiency programs. First,

[1] The NWA is in effect during the November through April winter period. In the months beyond April there are still amount reflecting April usage billed in May as well as very minor adjustments in other months related to cancel/rebill transactions that may be necessary for individual customer bills.

the relatively modest NWA adjustments provided above, especially when considered on an individual customer basis, would not be expected on their own to have much of an impact on customer behavior with respect to the energy efficiency programs. Second, it is important to keep in mind that decoupling only impacts the distribution portion of a customers' bills. Commodity prices have recently been lower than in the past, so when customers assess their overall bill, lower Cost of Gas prices also work into affecting customer behavior and the demand for energy efficiency measures. Finally, as described above, customers are currently receiving the benefit of a sizable credit through the RDAF. All of these factors working together, along with the infancy of the decoupling mechanism, make determining any measurable impacts on the Company's energy efficiency programs challenging at this time.

EnergyNorth's activities and efforts with respect to items 3), 4), and 5) above are summarized and detailed in Attachment SEM -2. Page 1 of that attachment provides a brief summary. Page 2 summarizes the total number of 2018 and 2019 activities along with providing the total number of activities associated with requirements 3), 4), and 5). The remainder of Attachment SEM-2 is a detailed list of each activity including the date and details as to the type of activity, the audience, the market segment (residential, C&I, etc.), and other relevant information.

There has not been much customer feedback or inquiries with respect to decoupling, with most of the inquiries occurring near the beginning of the implementation period. A list of the inquiries is provided in Attachment SEM-3. The Company also refers the

Commission to its report on the first 90 days of decoupling that was submitted to Staff on February 28, 2019, and was submitted to the Commission by Staff on March 4, 2019, as part of Docket No. DG 17-048.[2]

Finally, with respect to item 7), the Company has not experienced any changes to its credit rating as a result of the implementation of decoupling.

IV. TIMING OF RATE CASE FILING

Q. You mentioned earlier that the Company filed this rate case a number of months sooner than it had originally planned. Can you please describe some of the factors that led to the change in timing?

A. I previously described factors such as the lag on recovery for capital investments as well as increases in costs such as property taxes. In addition to those factors, there are financial impacts related to the implementation of decoupling that have negatively impacted the Company. Those factors include an increase in use per customer since the 2016 test year in the prior rate, as well as the reclassification of 1,598 commercial and industrial customers to other rate classes based on a review of their usage that occurred in February 2017. As that reclassification happened after the test year, it was not reflected in the DG 17-048 rate case. Each rate class has a different revenue per customer ("RPC") amount each month. With the customers being reclassified, that changed the results that would have otherwise been reflected in the class specific RPC amounts determined in the

[2] The Company's 90-day report on decoupling can be accessed at: http://www.puc.nh.gov/Regulatory/Docketbk/2017/17-048/LETTERS-MEMOS-TARIFFS/17-048_2019-03-04_STAFF_FILING_LIBERTY_DECOUPLING_RPT.PDF

rate case. Finally, as part of its decision in Docket No. DG 17-048, the Commission adopted a revenue adjustment originally proposed by Staff based on the year-end customer count of EnergyNorth as compared to the average number of customers during the test year and using average revenues by customer class. As the Company went through the months following the implementation of decoupling, it discovered that the adjustment had unintended consequences as it significantly overstated the number of estimated new customers and the amount of estimated annual revenue associated with those customers. The adjustment was performed in a simplified manner, but the results of that adjustment were found to vary significantly from the determination of revenues to be received from customers under the Company's decoupling structure that uses monthly RPC amounts that vary by class. Due to the significant variations in monthly RPC amounts, the simplified methodology in the year-end customer count adjustment overstated the amount of revenue to be received from new customers. This had the effect of decreasing the amount of necessary distribution revenue increase in the prior rate case which, in turn, lowered the RPC amounts calculated in that case. The longer the situation exists, the more the Company's revenues will be lower than necessary.

In Order No. 26,122, the Commission recognized that a reset of the test year revenues would be necessary and directed that the next test year to be used in a rate case be no later than a twelve-month period ending December 31, 2020. Given the impacts described above, the Company found it necessary to file this rate case at the present time to avoid a prolonged period of continued detrimental financial impacts.

Q. Does this conclude your testimony?

A. Yes, it does.