STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 20-105

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

DIRECT TESTIMONY

OF

MATTHEW J. DECOURCEY

July 31, 2020

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I. INTRODUCTION AND BACKGROUND

Q. Please state your full name, position, business address, and professional qualifications.

A. My name is Matthew DeCourcey. I am a Managing Director at FTI Consulting, Inc. ("FTI"), 200 State Street, 9th Floor, Boston, Massachusetts. My professional qualifications and experience are included as Attachment MJD-1.

Q. Please describe FTI's Power & Utilities practice.

A. FTI is a worldwide consulting firm dedicated to helping organizations manage change, mitigate risk, and resolve disputes. Our Power & Utilities practice brings these services to firms in regulated and competitive energy industries. The services we provide our utility clients include expert testimony, regulatory advice, support for strategic decision-making, and advice regarding investments and capital allocation. Our team is comprised of former utility executives, regulators, investors, and financial analysts that combine hundreds of years of experience in the regulated energy space.

Q. What is your responsibility in connection with this proceeding?

A. I am responsible for preparing the Marginal Cost Study ("MCS") for Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or "the Company") and for designing proposed rates for each of the Company's customer classes.

Q. How is your testimony organized?

A. My testimony is organized into three sections. This section, Section I, includes introductory material and describes the scope of my testimony. Section II describes the MCS that I prepared and its results. Section III discusses the development of the proposed customer class revenue targets, the proposed rates for each class, and describes bill impacts.

II. MARGINAL COST OF SERVICE STUDY

A. Overview and Summary of the MCS

Q. Please explain the concept of marginal costs and their applicability to natural gas utilities.

A. Marginal costs are defined as the change in total cost that results from increasing the output of a good or service by one unit. In the context of a gas utility, this means the added cost to serve one additional dekatherm ("dth") of demand or one additional customer. When a utility such as EnergyNorth is required to serve new demand or a new customer, it incurs a number of costs, including the cost of new infrastructure, increased Operations and Maintenance ("O&M") expenses and other administrative and operational costs. The MCS measures the degree to which each of those costs increases when an additional increment of demand or a new customer is added to the system. In addition to these costs, a utility would also need to procure gas supply to meet the needs of incremental demand or new customers; however, for purposes of this proceeding, that cost is excluded from the MCS because EnergyNorth's gas supply costs are recovered through the Company's Cost of Gas mechanism.

Q. How are the results of the MCS used in the ratemaking process?

A. The MCS establishes the marginal cost of a new customer or new increment of demand for each of EnergyNorth's rate classes. Marginal costs are then translated into revenue requirements, which reflect the annual levelized costs of incurring the marginal costs, inclusive of capital returns, taxes, depreciation, and other factors that are typically accounted for in utility ratemaking; annual levelized costs are equivalent to the Company's revenue requirement for each marginal cost incurred. The annualized levelized costs are, in turn, used to allocate the Company's revenue requirement, which is described in the joint testimony of Company witnesses David Simek and Kenneth Sosnick, to establish rates for each rate class. I discuss the development of the Company's rates in Section III of my testimony.

Q. Please briefly explain the economic theory underlying marginal cost analysis and its applicability to utility ratemaking.

A. It is an established principle in economics that when prices for goods or services are equal to the marginal costs to provide those goods or services, consumers will make decisions about their consumption that tend to optimize the allocation of resources. Thus, using marginal costs to establish EnergyNorth's distribution rates will help encourage consumers to make efficient decisions regarding their gas consumption. The New Hampshire Public Utilities Commission ("Commission") has recognized the appropriateness of using marginal costs for purposes of utility ratemaking in numerous proceedings, including the case in which the Company's gas distribution rates were last adjusted, Docket No. DG 17-048.

B. <u>MCS Methodology</u>

Q. Please explain your approach to conducting the MCS.

A. In conducting the MCS, I used data provided by the Company and approaches and methods that are generally consistent with the MCS EnergyNorth filed in Docket No. DG 17-048. The study was conducted in three parts. First, I analyzed the relationships between EnergyNorth's costs, its peak day demand, and its customer count. Some of EnergyNorth's costs increase primarily as a function of new demand, which I have categorized as capacity-related expenses. Other costs increase primarily as a function of new customers, which I have categorized as customer-related expenses. I also calculated a number of "loading factors," which account for relatively small costs whose causal relationships to other cost drivers are difficult to determine statistically. The results of these analyses indicate the initial marginal costs that EnergyNorth would incur to serve incremental demand and/or new customers. Second, I calculated Fixed Carrying Charge Rates ("FCCRs") to convert the initial marginal costs into the levelized, annual payment that the Company would require to recover its initial investment. Third, I summarized my findings and estimated the total marginal costs per dth of peak day demand and per customer for each of the Company's rate classes.

Table 1 below identifies each category of marginal costs that I analyzed and identifies the attachment to my testimony associated with each aspect of my analysis.

Table 1. Summary of MCS Analyses

Marginal Cost Category		**Attachment**
Capacity-Related Marginal Costs		
1	**Addition of production plant used in lieu of mains reinforcement**	**MCOS-1**
2	**Costs of mains reinforcements to meet incremental demand**	**MCOS-2**
3	**Costs of mains extensions to meet incremental demand**	**MCOS-2**
4	**Costs of distribution O&M to meet incremental demand**	**MCOS-2**
5	**Costs of production O&M to meet incremental demand**	**MCOS-2**
Customer-Related Marginal Costs		
6	**Costs to new plant additions (meters and services) to serve incremental customers**	**MCOS-3**
7	**Costs of O&M to serve incremental customers**	**MCOS-3**
8	**Costs of Accounting and Marketing to serve incremental customers**	**MCOS-3**
Loading and Adjustment Factors		
9	**Plant-related A&G loading factor**	**MCOS-4**
10	**Non-plant-related A&G loading factor**	**MCOS-4**
11	**MS and prepayments loading factor**	**MCOS-4**
12	**General plant loading factor**	**MCOS-4**
13	**Bad debt expense adjustment factor**	**MCOS-4**
Levelized Annual Marginal Costs		**MCOS-5**
Summary of results		**MCOS-6**

Q. Please summarize the method you used to estimate the capacity- and customer-related marginal costs shown above.

A. My estimate of the marginal cost to add production plant in lieu of mains reinforcement, listed above as Item 1, is based on an analysis of engineering data provided by the Company, as I explain in detail later in my testimony. To estimate the marginal costs associated with Items 2 through 8, I first conducted regression analyses using data the Company provided. If the resulting regression equation that I estimated to parameterize the driver of each cost category was sufficiently robust, it was used to estimate the marginal cost. If it was not, I based the marginal cost for each category on historical actual cost rates, as I explain in more detail below.

Q. Please explain the general approach that you used in conducting the regression analyses.

A. The Company provided annual cost data for the period 1989 to present for each of the cost categories listed as Items 2 through 8 in Table 1. I adjusted expense data using a general inflation index and adjusted the plant cost data using the most recent version of the Handy Whitman Index.[1] EnergyNorth also provided annual peak day consumption and annual customer counts for the same period. For each of the capacity-related marginal costs (Items 2–5 above), I regressed the cost items against peak day consumption. For the customer-related marginal costs (Items 6–8), I regressed the cost items against annual customer count. Among the results produced is a coefficient that

[1] The Handy Whitman Index calculates cost trends for specific sectors, which allows for the estimation of industry-specific inflation calculations. To develop the calculations described in my testimony I used Bulletin No. 191, the most recent available, of the Handy-Whitman Index of Public Utility Costs.

indicates the slope of the regression line found to be the best fit in the data. The coefficient indicates the rate at which the cost variable would increase for every unit change in the independent variable, either demand, in which case the rate of change in costs is expressed on a $/peak day dth basis, or customer count, in which case the rate of change is expressed on a $/customer basis.

More formally, the regression equations can be summarized as follows:

$$\textit{Cost Variable} = a + b * \textit{Cost Driver Variable}$$

where the *Cost Variable* is the cost data provided by the Company for each category identified in Items 2–8 in Table 1. The *Cost Driver Variable* is the Company data for either demand (for capacity-related marginal costs) or customer count (for customer-related marginal costs). *a* is the y-axis intercept of a line that is fit to the data available using regression analysis; that line is often referred to as being defined by the regression line. *b* is the coefficient that represents the slope of the regression line, which is the rate at which the *Cost Variable* increases with each unit of the *Cost Driver Variable*; thus, for purposes of the MCS, *b* indicates the unit marginal cost for each of the cost categories shown above for which I was able to estimate a sufficiently robust relationship using linear regression.

Q. Is regression analysis a widely accepted method for conducting marginal cost studies?

A. Yes, the method I used is widely accepted. Regression analysis is used in New Hampshire and elsewhere for marginal cost studies for gas and electric utilities and was also used in Docket No. DG 17-048, the last rate case where the Company's distribution rates were adjusted. Additionally, the use of historical cost rates in instances in which a sufficiently robust relationship between cost and driver variables cannot be found using regression is also common practice in New Hampshire and other jurisdictions.

Q. How did you determine which of the regressions satisfactorily capture the relationship between the cost and driver variables?

A. There were three primary criteria I utilized to confirm that the regression equations I have identified adequately capture the relationship between the cost variable and the cost driver variable. *First*, I reviewed the R-squared statistic, which is sometimes referred to as the coefficient of determination. R-squared is the square of the coefficient of correlation between the *Cost Variable* and the *Cost Driver Variable* and is a statistical measure of how closely the data fit the regression line. *Second*, I confirmed that each of the regression coefficients – the *b* or slope variables – had the expected sign. In this case, that means that all of the coefficients should be positive, indicating that as peak demand increased, expense would as well. *Third*, I reviewed the t-statistic and p-value for each regression, both of which are measures of the explanatory power of the *b* coefficient.

Q. Did you reject any regressions?

A. Yes, I did. In several instances I rejected the results of the regression analysis because the equation indicated a coefficient with a negative sign, a low R-squared value, or both. As I describe in detail below, in each of those instances I based my estimate of the marginal cost for that cost category on long-run cost rates that I calculated using the data provided by the Company.

1. Capacity-Related Marginal Costs

Q. Please summarize the capacity-related marginal costs that you estimated using regression analysis.

A. I estimated five types of marginal costs that the Company would incur for each additional increment of design day demand, each of which are listed in Table 1: (Item 1) marginal costs associated with the addition of new production plant that the Company could install in lieu of reinforcing its network of distribution mains; (Item 2) marginal costs of investing to reinforce mains to meet each increment of new demand; (Item 3) marginal costs of extending mains to meet each increment of new demand; (Item 4) marginal distribution O&M costs associated with serving each increment of new demand; and (Item 5) marginal production O&M costs associated with serving each increment of new demand.

Q. How did you estimate Item 1, the marginal cost of new production in lieu of mains reinforcement to serve incremental demand?

A. EnergyNorth owns Liquid Propane ("LP") and Liquefied Natural Gas ("LNG") facilities in its service territory, which it uses to maintain pressure when its system is at or near peak demand conditions. I asked the Company to develop an estimate of the costs of hypothetical additions to expand the capacity of its LP and LNG facilities and also to determine how much of that new capacity would be used to maintain system pressure.

Upon review of its engineering data, the Company determined that the cost estimates and allocation to pressure support used for the MCS in Docket No. DG 17-048 were still current. Those costs indicated that LNG was the preferred alternative; that in 2016 it would have cost $6,417,870 to increase its LNG capacity by 10,000 dth; and that 8.73% of that capacity would be used to maintain pressure during peak conditions. I therefore increased the capital expense amount by approximately 6.2% to account for three years of inflation between 2016 and 2019. I determined this rate by reviewing the U.S. Bureau of Economic Analysis's Gross Domestic Product Implicit Deflator, which was most recently published in May 2020. The result is a marginal unit cost estimate for production plant to maintain pressure support of $59.52/dth of incremental design day demand. My calculations are shown in Attachment MCOS-1.

Q. How did you estimate Item 2, the marginal cost of mains reinforcement to serve incremental demand?

A. Mains reinforcement costs are the costs that the Company incurs for reinforcing its system to maintain operations to meet incremental demand. I asked the Company to prepare an engineering study that forecasted system reinforcement projects that EnergyNorth expects to install over the period 2021 to 2030 in response to growing demand and the expected costs of those projects. I then developed a regression analysis to estimate the statistical relationship between the cost of those reinforcement costs and demand. As shown in Attachment MCOS-2 at page 1, I found that the marginal cost of mains reinforcement is $1,261.97/dth of incremental design day demand.

Q. How did you estimate Item 3, the marginal cost of mains extensions to meet incremental demand?

A. The marginal cost for mains extension is the cost that EnergyNorth will incur to extend its network for each dth by which demand grows. The Company provided me with data for the period 1989–2019 that included the costs of new mains and peak day demand for each year. Using this data, I conducted regression analysis to estimate the relationship between those two variables and determined that the marginal cost of mains extensions is $1,090.65/dth of incremental design day demand, as shown in Attachment MCOS-2 at page 2.

Q. How did you estimate Item 4, the marginal cost of distribution O&M to serve incremental demand?

A. The Company provided me with data for O&M related to distribution operations for the period 1989–2019. I conducted regression analysis to estimate the relationship between those cost data and peak day demand, which indicated that the Company's marginal cost of distribution O&M is $46.87/dth of incremental design day demand, as shown in Attachment MCOS-2 at page 3.

Q. How did you estimate Item 5, the marginal cost of production O&M to meet incremental demand?

A. Production O&M costs are those costs that EnergyNorth incurs for the operation and maintenance of its LNG and LP facilities. To estimate that cost, I first ran a regression to determine the relationship between design day demand and total production related expenses using data provided by the Company. However, the resulting equation had a negative sign and low R-squared value, so I rejected it and instead estimated the marginal cost using EnergyNorth's historical average production cost, which I determined to be $13.21/dth of incremental design day demand. Because that estimate is total production cost, it must be allocated to the distribution function, since the objective is to determine the marginal cost of pressure support. To do so, I utilized the same rate, 8.73%, that was used to allocate the cost of new production in lieu of mains to the pressure support function. The resulting estimate of the marginal cost for production O&M is $1.15/dth of incremental design day demand, as shown in Attachment MCOS-2 at page 4.

2. Customer-Related Marginal Costs

Q. Please explain the concept of customer-driven marginal costs.

A. For some cost categories, the Company's costs are driven more by the number of its customers than by customers' total consumption. For example, EnergyNorth's cost of meters is driven entirely by its customer count – a meter must be installed for each new customer regardless of consumption. For each of the customer-driven cost categories, the marginal cost is equal to the Company's additional expense in that category that results from a single new customer. Accordingly, each of the customer-driven marginal costs are expressed on a $/customer basis.

Q. Please summarize the customer-related marginal costs that you estimated.

A. I estimated three types of marginal costs that the Company would incur for each new customer: (Item 6 from Table 1) the costs of new plant additions for each incremental customer; (Item 7) O&M costs associated with the new plant additions for each incremental customer; and (Item 8) Accounting and Marketing costs the Company will incur for each new customer.

Q. How did you estimate Item 6, the marginal cost of plant additions to serve incremental customers?

A. Customer-driven marginal costs of plant additions are the costs of installing a meter and service for new customers. The Company provided me with its current costs by rate class, which are shown below. Additional detail is provided in Attachment MCOS-3 at page 1:

Table 2. Marginal Costs of Customer-Related Plant Additions

	R-1	**R3, R-4**	**G-41**	**G-42**	**G-43**	**G-51**	**G-52**	**G-53**	**G-54**
Service	$4,063	$4,063	$3,796	$6,346	$10,913	$11,894	$6,583	$39,407	$9,647
Meter	$440	$440	$1,077	$2,750	$9,333	$3,483	$2,750	$3,995	$11,904
Total	$4,503	$4,503	$4,873	$9,097	$20,245	$15,376	$9,333	$43,403	$21,552

Q. How did you estimate Item 7, the marginal cost of O&M to serve incremental customers?

A. Customer-driven O&M expense is the expense that the Company incurs to operate and maintain its meters and services; as such, it is separate from the Company's distribution O&M discussed above. To estimate the marginal cost of customer-related O&M, I first developed regressions based on historical data for customer-related O&M and annual customer count which the Company provided. Because the resulting regression equation had an extremely low R-squared value, I rejected it and instead based my estimate of the marginal cost on the Company's long-run average O&M cost per customer, which is $66.45/customer, as shown at page 2 of Attachment MCOS-3. Because customer-related O&M is likely to vary by rate class, I conducted additional analysis to weight the marginal costs for each class based on the contribution of each class to total costs, as shown at page 3 of Attachment MCOS-3. The resulting marginal cost for O&M to serve incremental customers for each rate class is shown below:

Table 3. Weighted Customer-Related Marginal O&M Cost by Class

Class	**Class weighted marginal cost per customer**
R1	$62.26
R-3, R-4	$62.26
G-41	$67.38
G-42	$125.77
G-43	$279.92
G-51	$212.60
G-52	$129.04
G-53	$600.10
G-54	$297.99

Q. How did you estimate Item 8, marginal Accounting and Marketing costs to serve incremental customers?

A. The Company provided historical data for Accounting and Marketing expenses for the period 1989 to present. I prepared a regression analysis to determine the statistical relationship between those expenses and annual customer count. Because that analysis showed a very weak relationship, as measured by the correlation value, between customer count and Accounting and Marketing expense and also a negative coefficient, I chose to base my estimate of the marginal cost for that category of $65.88/customer using the Company's actual long-run average rate. My calculations are shown at page 4 of Attachment MCOS-3.

3. Loading and Adjustment Factors

Q. Please identify the loading factors you estimated.

A. The loading factors I calculate are for (a) plant-related administrative and general ("A&G") expense, (b) non-plant-related A&G expense, (c) materials and supplies ("M&S") and prepayments, and (d) general plant.

Q. What is the relevance of the loading factors to the MCS?

A. Each of the loading factors define relatively small costs that the Company will incur as a result of increasing demand and/or customer count that should be included in its marginal cost but that are difficult to estimate directly using the statistical approaches described above. I therefore based my estimates of the loading factors on the historical relationship between these cost categories and other costs from data that was provided by the Company. For example, I compiled the Company's total utility plant cost and its plant-related A&G expense for each year for the period 1989 through the present and determined that, on average, plant-related A&G expense was approximately 0.61% of the total utility plant cost. I conducted similar analyses for each of the other loading factors, including comparisons of non-plant A&G expense to adjusted O&M, M&S and prepayments to total utility plant, and general plant to total utility plant. My calculations are provided at pages 1–4 of Attachment MCOS-4 and are summarized in Table 4, below:

Table 4. Summary of Loading Factors

Category	**Loading Factor**	**Unit**
Plant-related A&G expense	$0.0061	/$ of utility plant
Non-plant related A&G expense	$0.6616	/$ of adjusted O&M
M&S and prepayments	$0.0131	/$ of utility plant
General Plant	$0.0549	/$ of utility plant

Q. Did you calculate any other adjustment factors?

A. Yes, using data provided by the Company, I calculated a percentage-based estimate of bad debt expense per customer class, as shown at page 5 of Attachment MCOS-4.

4. Levelized Marginal Costs

Q. Please explain the relevance of the levelized marginal costs.

A. Each of the marginal costs for investments in infrastructure described earlier in my testimony are the initial costs that will be incurred by the Company to place services, meters, and plant into service to serve new demand or customers. These costs must be converted into levelized, annual costs that include recovery of the Company's authorized return and other factors in order to establish marginal costs that reflect EnergyNorth's cost of service.

Q. How did you convert the initial marginal costs into levelized marginal costs?

A. I calculated FCCRs for each type of investment that the Company would incur to meet new demand or to serve new customers: (a) production plant, (b) mains, (c) services, and

(d) meters. For each, I calculated an Engineer's FCCR and an Economist's FCCR, which are the annual revenue requirements, expressed as a percentage of the initial capital investment, for each type of investment, inclusive of the Company's required returns, taxes, depreciation, and other factors that are reflected in utility ratemaking for capital investment. The only difference between the two rates is that the Engineer's FCCR is expressed in nominal dollars while the Economist's FCCR is expressed in constant dollars that account for the value of inflation; the Present Value ("PV") of the income streams that underlie the FCCR calculations are the same for both. For purposes of marginal cost analyses, it is generally accepted that use of the Economist's FCCR is most appropriate, which is consistent with the Company's MCS in Docket No. DG 17-048. The inputs that I used to conduct the levelized cost analysis are shown at pages 1–2 of Attachment MCOS-5, the detailed calculation of the four FCCRs are shown at pages 3–6 of Attachment MCOS-5, and the Economist's and Engineer's FCCRs are shown at page 7 of Attachment MCOS-5.

C. <u>MCS Results</u>

Q. Please identify the schedules you have prepared to summarize the results of the Marginal Cost Study.

A. Attachment MCOS-6, page 1, shows the calculation of capacity-related marginal costs inclusive of loading factors and adjustments. Attachment MCOS-6, page 2, shows the calculation of customer-related marginal costs, including all loading factors and adjustments. Attachment MCOS-6, page 3, summarizes the cost estimates.

Q. Please summarize the results of the MCS.

A. The results of the MCS are summarized in Table 5, below.

Table 5. Marginal Costs by Rate Class ($,000)

Class	Customer -related	Capacity-related	Total	Share
R-1	$2,403	$176	$2,579	2.0%
R3, R-4	$53,177	$25,674	$78,851	61.6%
G-41	$6,620	$11,246	$17,866	14.0%
G-42	$1,746	$13,608	$15,354	12.0%
G-43	$154	$3,900	$4,054	3.2%
G-51	$2,620	$815	$3,434	2.7%
G-52	$494	$1,863	$2,357	1.8%
G-53	$182	$1,998	$2,180	1.7%
G-54	$79	$1,152	$1,230	1.0%

III. <u>RATE DESIGN</u>

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

A. In this section of my testimony I describe the analysis I undertook to develop proposed rates for each of the Company's rate classes. I also discuss an issue with the decoupling mechanism approved in the Company's last rate case that I believe merits an adjustment by the Commission.

Q. How is this section of your testimony organized?

A. In this section of my testimony I summarize at a high level my approach to undertaking the rate design. I also describe the billing and revenue data that the Company provided me and describe in detail my calculation of the proposed distribution rates. Additionally, I explain the analyses that I undertook to calculate the changes to other pass-through charges allowed by the Company's tariff. Finally, I describe the analysis of bill impacts by customer class that I conducted.

A. Rate Design Overview

Q. Please summarize at a high level your approach to developing proposed rates.

A. The objective of the rate design analysis is to identify a set of rates that allows the Company to recover its allowed revenue requirement given normal throughput volumes, that adheres to principles related to rate continuity that I describe in more detail below, and that reflect the Company's marginal cost to serve customers in each class. To do so, I calculated the revenues that the Company would earn at current rates, assuming that throughput is the same as was observed in the test year, subject to certain adjustments I describe later in this section of my testimony.[2] When I determined that those revenues would be less than the Company's requirements, I calculated the increase, expressed on a percentage basis, that would eliminate any revenue shortfall. The required increase and the results of the MCS were used to determine how much to increase rates in each class. After I had calculated the proposed rates, I confirmed that they would generate revenues that would meet the Company's revenue requirement.

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[2] The test year is 2019.

Q. Have there been any significant, recent changes to the Company's rate design?

A. In August 2016, the Company received permission from the Commission to offer a new set of rates to customers initiating service under the Managed Expansion Program ("MEP").[3]

Q. Please summarize the MEP and the relevant rates.

A. Previously, new customers who required the construction of new facilities, often in the form of mains extensions, were frequently required to make an upfront payment for the costs of those facilities, referred to as a Contribution in Aid of Construction ("CIAC"), as a condition of starting service. The Company found that in some cases, developers were opting for propane service to avoid having to pay the CIAC.[4] The MEP was designed as an alternative to the CIAC and imposes a premium of 30% on both customer and volumetric charges on the rates for the class of which the customer would otherwise be a part. For example, a C&I customer initiating service who meets all the criteria of the G-41 rate class could be assigned to the G-44 class, in which case the customer would receive service subject to all the same terms as a G-41 customer except for the higher rate. The value proposition for such customers is the avoidance of the CIAC. The premium embedded in the MEP rate is designed to generate approximately the same amount of revenue, over time, that would have been recovered on an upfront basis via the CIAC. New customers assigned to a MEP rate class receive service under that tariff for 10 years, after which they revert to the applicable non-MEP tariff. There is a MEP

[3] Commission Order No. 25,933, issued August 4, 2016.
[4] *Id.* at p. 3.

variant for each of the rate classes that have typically been in use for the Company (herein referred to as the "standard" rate classes for simplicity). Table 6 shows the Company's standard rate class and equivalent MEP rate class for each type of customer.

Table 6. Standard and MEP Rate Classes

Type	Description	Standard Rate Class	Equivalent MEP Rate Class
Residential	Non-Heating	R-1	R-5
	Heating	R-3	R-6
	Heating (Low Income)	R-4	R-7
C&I	Low Annual Use, High Winter Use	G-41	G-44
	Medium Annual Use, High Winter Use	G-42	G-45
	High Annual Use, High Winter Use	G-43	G-46
	Low Annual Use, Low Winter Use	G-51	G-55
	Medium Annual Use, Low Winter Use	G-52	G-56
	High Annual Use, Low Winter Use	G-53	G-57
	High Annual Use, Load Factor > 90%	G-54	G-58

Q. Aside from the MEP rate classes, are rates for any other class a function of some related class?

A. Yes. Rate class R-4 is provided under the Residential Low Income Assistance Program ("RLIAP"). Each component of the R-4 distribution rates is set at 60% of R-3 rates. There is also an equivalent MEP rate, such that R-7 rates are set at a discount to R-6 rates (or, alternatively a 30% premium to the R-4 rates). Customers are eligible for service under one of the RLIAP rates if they receive food stamps, disability or old age assistance, participate in a fuel assistance program, or receive some other support program.[5] The RLIAP discount applies only to distribution rates, not the cost of gas.

Q. Have there been any other notable changes to the Company's ratemaking?

A. Yes. This is the first proceeding in which the Company is proposing a single set of distribution rates for all its customers, including the Keene service territory. Previously, Keene customers had received service under a separate set of rates. All of the volume, revenue, and related data discussed in the remainder of my testimony includes the Keene customers.

Q. Are you proposing any adjustments to reflect the impact of the Concord Steam acquisition?

A. No. In previous proceedings, the Company had included adjustments in its calculation of rates that reflected certain aspects of its 2017 acquisition of Concord Steam, many of whose customers have chosen to take service from EnergyNorth after the transaction and subsequent closure of Concord Steam's plant. Those customers that did so have been fully integrated into EnergyNorth's systems. As such, an adjustment is no longer required.

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5 A detailed listing of programs that define the RLIAP eligibility criteria is available on the Commission's website at: https://www.puc.nh.gov/consumer/gasassistanceprogram.htm#:~:text=The%20Gas%20Residential%20Low%20Income,delivery%20portion%20of%20their%20bill

B. Billing and Revenue Data

Q. What data did you use to develop the rates you are proposing?

A. In addition to the MCS results, I used the output of the Cost of Service and Functional Cost of Service Studies (collectively the "COS Studies") that Messrs. Simek and Sosnick describe in their joint testimony. I also used information from Company rates already approved by the Commission. Finally, I utilized billing data from the test year and gas cost data for the 2019/20 winter that were provided to me by the Company.

Q. Has the test year data that the Company provided been validated?

A. Yes. Included with my testimony as Attachment RATES-1 is a revenue proof that validates the billing data I used. The proof contains data from the Company's billing system showing customer count, sales, and revenues by month and by rate class for the test year that indicate that the Company earned $86,453,445 over that period.[6] It also includes a re-calculation of revenues for the same period based on actual rates in effect which, indicating earnings of $86,454,281, a difference of roughly 0.001%.[7,8]

Q. Were the billing determinants shown in RATES-1 adjusted in any way before you used them in your rate design calculations?

A. Yes, four adjustments were made: (a) a calendarization adjustment; (b) an adjustment to separate sales volumes into usage blocks; (c) a weather normalization adjustment; and (d)

6 p. 2, ln. 25
7 ln. 50
8 p 3, ln. 50

an adjustment to correct for changes that occurred to the Company's customer base over the course of the test year.

Q. Please explain the calendarization adjustment.

A. The calendarization adjustment accounts for differences between the billing cycles that EnergyNorth uses and calendar months. It was calculated by the Company and provided to me. Adjustments to monthly customer counts and sales volumes are shown on p. 1–2 and p. 3–4, respectively, of Attachment RATES-2.

Q. Please explain the block rate structure EnergyNorth uses to set rates for some of its customers.

A. The Company's tariffs define volumetric charges for several classes of C&I customers using what is referred to as a block rate structure. Each month, customers in those classes are charged a rate for all usage up to a pre-defined limit. If usage exceeds that limit, a different rate is applied for consumption for the remainder of the month. EnergyNorth refers to the two quantities as the "headblock" and "tailblock" volumes, respectively. For all classes that use this structure, the tailblock rate is lower than the headblock rate, a design sometimes referred to as a "declining block structure." Table 7 shows the size of the headblock for each of the rate classes that use the block rate structure. Note that in some instances, the size of the headblock differs by season.

Table 7. EnergyNorth Customer Classes Using Block Rate Structures (therms)

Standard Rate Class	Equivalent MEP Rate Class	Summer Headlock Size	Winter Headblock Size
G-41	G-44	20	100
G-42	G-45	400	1,000
G-51	G-55	100	100
G-52	G-56	1,000	1,000

No changes are being proposed to the structure or sizes of any of the blocks. Additionally, as I explain below, the rates I propose maintain the pricing relationships embedded in the current tariff between headblock and tailblock volumes as well as the relationships between summer and winter volumes.

Q. Please explain the adjustment that was made to the determinants to determine headblock and tailblock volumes.

A. The Company maintains billing data from actual (un-calendarized) sales that shows the percentage, each month, of sales that fall into each of the headblock and tailblock for customers in each of the classes shown in Table 7. Those percentages were applied to the calendarized data to show usage by block. The adjustment is shown on p. 4 of Attachment RATES-2 at Lines 26–47. The resulting headblock and tailblock volumes by month and by rate class are shown at p. 5 of the same attachment.

Q. Please explain the weather normalization adjustment.

A. The purpose of using billing determinants from a test year is to define the quantity of sales likely to occur in subsequent years. Although the historical data are indicative of future volumes for obvious reasons, in some years, weather will be colder than normal, which tends to increase throughput, while in some years it will be warmer, which has the opposite effect. In order to project annual sales, on average, moving forward, adjustments need to be made to correct for the particular weather outcomes that affected test year volumes. To do so, the Company analyzed weather data on a month by month basis for all winter months to determine the degree to which temperatures during the test year diverged from long-run averages. Because weather variances primarily impact heating demand and because there is little heating demand during the non-winter months, weather normalization of summer sales volumes is unnecessary. The results of the temperature analysis were input into models of the relationships between weather and volumes that the Company maintains to develop a counterfactual estimate of what sales would have been had the weather been normal – which is to say completely consistent with historical average temperatures – each winter month during the test year. The resulting adjustment is calculated separately for each rate class and for each month of the test period and is shown at p. 6 of RATES-2. The normalized volumes that result from applying the adjustment are shown at page 7–8. As the adjustment data indicate, January and November during the test year were colder than normal, so an adjustment was made to normalize the sales volumes by reducing actuals for those months. February, March, April, and December were warmer than normal, so an adjustment was made to increase actual sales for those months. For the entire test period, the normalization adjustment reduced volumes by 1,789,257 therms, or about 1% of throughput. The weather normalization applied to each class is shown in Table 8.

Table 8. Weather Normalization Adjustment by Class (therms)

	Non-Normalized	Adjustment	Normalized
R-1	730,007	(4,929)	725,078
R-3	58,627,344	(724,476)	57,902,868
R-4	4,592,696	(55,270)	4,537,425
R-5	15,553	0	15,553
R-6	165,208	0	165,208
R-7	1,767	0	1,767
G-41	24,966,957	(327,756)	24,639,201
G-42	35,010,164	(445,124)	34,565,040
G-43	11,283,618	(120,548)	11,163,070
G-44	10,101	0	10,101
G-45	133,489	0	133,489
G-51	4,129,466	(18,262)	4,111,204
G-52	9,564,929	(46,454)	9,518,475
G-53	10,522,907	(46,438)	10,476,470
G-54	18,002,982	0	18,002,982
G-55	3,525	0	3,525
G-58	278,754	0	278,754
Total	178,039,468	(1,789,257)	176,250,211

Rate classes G-45, G-56, and G-57, each of which are MEP rates, are excluded because no sales were recorded for those classes during the test year.

Q. Is the weather normalization adjustment necessary given that the Company's rates are decoupled?

A. Yes. Rate decoupling adjusts revenues the Company earns on a per-customer basis to enable it to recover its revenue requirement despite changes in weather, customer consumption patterns, economic conditions, and other factors that could otherwise affect throughput and revenues. This fact notwithstanding, it is still important to establish rates that reflect the Company's operational and financial reality to the greatest extent possible in order to provide customers with information they need to make efficient consumption and investment decisions and promote transparency.

Q. Please summarize the End of Year ("EOY") Adjustments.

A. Over the course of any year, including the test year, the Company gains and loses customers. The EOY Adjustments recognizes this effect by annualizing the billing units and revenues of new customers present at the end of the test year while removing the billing units and revenues of customers who terminate service during the year. The Company provided me with separate adjustments to customer bill counts, sales volumes, and revenues, which were calculated using data from its billing system.

Q. Please describe the adjustments to customer bill counts.

A. For each of the non-MEP classes, the Company identified each customer who had been added during the test year and determined how long they had taken service, from which it calculated how many bills such customers had received during the year (an amount which includes fractions of months). Based on this information, an adjustment was made to the monthly bill count for each customer class that effectively adds new customers to the bill count as if it had been there all year. Using the same approach, a similar adjustment was calculated to the bill count based on customers who started the year receiving service from EnergyNorth but then departed.

Q. Can you provide an example?

A. Yes. Assume that a customer began taking service from EnergyNorth on September 1. Without an adjustment, it would contribute to the customer bill count, sales volumes, and revenues for September, October, November, and December only. The bill count adjustment increases the bill count by one customer for each of the eight months that precede September. The example is simplified in the sense that there may be slight variances in the number of bills issued per month based on the number of days in each month since the Company's billing periods are each 30 days rather than a calendar month.

Q. What is the net impact on customer bill count from the adjustment?

A. Because more customers began taking service than terminated service during the year, there was an aggregate increase, which is shown by month below for residential and C&I customers. Note that the adjustment is largest in January and smallest in December since it is intended to reconcile against EOY effects.

Table 9. EOY Customer Bill Count Adjustment

	Residential	C&I	Total
January	936.1	148.4	1,084.5
February	754.2	115.1	869.4
March	782.4	126.4	908.7
April	738.5	122.4	861.0
May	746.1	141.2	887.3
June	674.5	151.1	825.7
July	703.3	173.8	877.1
August	683.2	179.5	862.7
September	500.7	168.8	669.6
October	330.2	122.7	452.9

	Residential	C&I	Total
November	165.2	49.4	214.6
December	(8.6)	14.3	5.7

Q. Were sales volumes also adjusted?

A. Yes. The Company calculated average headblock and tailblock usage per customer bill for each class, which was applied to the changes in customer bill count shown above to generate the adjustment to volumes. The volumetric adjustment for residential and C&I customers that results is shown in Table 10.

Table 10. EOY Volumetric Adjustment (therms)

	Residential	C&I		Total
	Headblock	Headblock	Tailblock	
January	131,310.2	82,034.4	113,384.4	326,728.9
February	99,225.7	59,135.8	96,311.3	254,672.7
March	84,235.1	68,534.3	87,444.0	240,213.5
April	41,673.9	41,930.5	38,544.5	122,149.0
May	25,373.2	17,096.5	24,185.1	66,654.8
June	13,149.3	5,138.1	16,015.0	34,302.3
July	9,770.4	18,396.2	11,464.4	39,631.0
August	9,611.0	18,751.0	10,722.5	39,084.4
September	9,336.1	20,989.1	13,435.9	43,761.1
October	12,677.5	18,572.6	21,968.7	53,218.7
November	12,300.3	8,794.8	19,498.0	40,593.1
December	(409.2)	4,115.3	7,797.6	11,503.7

Q. Do these adjustments increase the Company's test year revenues assumed for ratemaking purposes?

A. Yes. Revenues from customer charges are increased based on the adjustment to customer bill count and the currently effective customer charges while revenues from volumetric sales are increased based on the adjustment to sales quantities and the volumetric rates currently in effect. Note that these calculations are conducted on a class-by-class basis, despite the adjustments being aggregated for simplicity above in Table 9 and Table 10. The net effect is an increase in the Company's revenues for ratemaking purposes of approximately $756,000. The result is summarized below while detailed calculations showing the derivation of that amount are provided in the Workpaper entitled "RATES-5 WP – EOY Adjustment," which is included in Attachment RATES-5 to this testimony.

Table 11. Revenue Impact of EOY Adjustments

	Residential	C&I	Total
January	$93,481	$73,593	$167,074
February	$71,832	$57,429	$129,261
March	$63,491	$58,164	$121,655
April	$37,205	$37,522	$74,727
May	$27,184	$25,479	$52,663
June	$18,736	$19,936	$38,672
July	$16,952	$21,615	$38,567
August	$16,352	$21,103	$37,455
September	$13,146	$21,381	$34,527
October	$12,302	$20,533	$32,835
November	$9,898	$12,590	$22,488
December	$582	$5,065	$5,647
Total	$381,160	$374,410	$755,571

Q. Where are the EOY Adjustments reflected and how does it affect the rate calculations?

A. As I explain later in my testimony, the rate calculations shown in Attachment RATES-5 are based on the shortfall between revenues at current rates and the Company's revenue requirement. The adjustment to revenues, which is shown at Line 9 of RATES-5, reduces that shortfall. The increases to customer bill count and sales volumes are also accounted for when rates are calculated. In both respects, inclusion of the adjustment puts downward pressure on the proposed rates.

C. Rate Calculations

Q. Please summarize the steps you undertook to develop the rates you are proposing.

A. Summarized at a high level, my approach consisted of eight steps. *First,* I determined the target amount of revenue the Company would be required to recover through its distribution rates. That amount is based on the COS Studies, the results of which I adjusted for a number of factors. *Second,* I compared the Company's total marginal cost of service, whose calculation I describe in Section II, to the Company's revenue target. Since the marginal cost of service is greater than the amount to be recovered, I applied an adjustment using the Equiproportional Method ("EPM") to achieve consistency between the MCS and the COS Studies. *Third,* I calculated the amount of revenue the Company would generate given test year billing determinants and the distribution rates currently in effect. Since those revenues are insufficient to recover the revenue requirement, I also calculated the increase in revenues that would be required to achieve the revenue target. *Fourth*, I increased the customer charge for each rate classes by a factor equal to the total required revenue increase, expressed on a percentage basis. I also calculated the amount of revenue the Company would generate from the new customer charge rates. *Fifth,* I adjusted the expected revenue for certain classes to limit the potential for inconsistent bill impacts and to promote rate continuity objectives. *Sixth,* I determined how much the

Company would be required to recover from rates for each class based on current rates, the results of the MCS, and additional adjustments I applied. In doing so, I established for each class a total revenue target and the revenue required from volumetric sales. *Seventh*, I calculated the volumetric rates that would recover each class revenue target. *Eight*, I validated that the rates that resulted would allow the Company to generate revenues equal to the revenue target for each class and to the Company's overall requirement. All of the calculations I undertook to do so are shown in Attachment RATES-5 and its associated workpapers.

Q. How much revenue are your proposed rates designed to recover?

A. The proposed rates are designed to recover revenue of $103,936,008. That amount is established by the COS Studies, reduced by non-delivery revenues, increased by the step adjustment described by Messrs. Simek and Sosnick in their testimony, and increased by the amount required to recover the discount the Company provides to its RLIAP customers. The derivation of the revenue target is shown below, additional detail is provided at Lines 59-66 of RATES-5.

Table 12. Calculation of Total Rate Recovery Amount

Line Item	Amount	Reference
Delivery revenue requirement	$97,277,247	COS Studies
Non-delivery revenues	($1,197,776)	RR-EN-2-1
RLIAP recovery	$2,175,896	RATES-5
Step adjustment	$5,680,641	RR-EN-1
Total	$103,936,008	

Q. Please explain the RLIAP recovery amount.

A. The Company recovers the discount it provides to RLIAP customers through sales to other customers. To calculate the value of that discount, I calculated the difference between the revenues from the RLIAP customers and the amount their payments would be under the corresponding non-RLIAP rates (R-3 rates for the R-4 customers and R-6 rates for the small handful of those customers taking service under R-7). The result indicates that the total value of the discount to RLIAP customers is $2,175,896. Detail supporting my calculation of that amount is provided in the workpaper labelled "RATES-5 WP – RLIAP", which is attached to RATES-5.

Q. Is the amount the Company must recover from rates the same as its marginal cost of service?

A. No. The Company's total marginal cost is approximately $128 million, based on the results of the MCS that are shown above in Table 5. That amount is roughly 18.7% greater than the revenues the Company will recover under the proposed rates. To reconcile the difference, I applied an EPM adjustment factor to my estimate of the Company's marginal cost to serve each rate class so that its total marginal cost would match the Company-wide revenue target. As I explain below, differences remained between the Company's marginal cost to serve specific rate classes and the corresponding revenue targets for each class. Calculation of the EPM adjustment is shown below in Table 13 and also at Lines 67–76 of RATES-5.

Table 13. Calculation of the EPM Adjustment Factor to the MCS

Customer-related marginal costs	$67,473,706	*a*
Capacity-related marginal costs	$60,430,869	*b*
Total marginal costs	$127,904,576	*c=a+b*
Recovery amount	$103,936,008	*d*
EPM adjustment factor	-18.7%	*e=(d-c)/c*

Q. Please explain the EPM adjustment factor and how you applied it.

A. Simply put, it is the adjustment to the marginal cost of service estimate that is required for the total marginal cost of service to match the amount to be recovered in rates. The adjustment is "equiproportional" in the sense that it is applied uniformly to the calculated marginal cost of providing service to each rate class. In this instance, proportionality is achieved by making the adjustment to both customer-related and capacity-related marginal costs on the basis of a single factor, the percentage differential shown above.

Q. Would the Company generate sufficient revenue at current rates?

A. No. Using the determinants I described previously and the distribution rates the Commission approved in June 2020 in Docket No. DG 20-049, I found that the Company would earn approximately $88.8 million per year at current rates.[9] My calculations are summarized below and shown in detail in the workpaper labelled "RATES-5 WP – Determinants", which is attached to RATES-5, and at Lines 3–8 of RATES-5.

[9] Commission Order No. 26,374, issued June 30, 2020.

Table 14. Revenue at Current Rates

	Winter	**Summer**	**Total**
Customer revenues	$13,506,098	$13,499,124	$27,005,223
Volumetric revenues	$50,918,418	$10,847,346	$61,765,764
Total	$64,424,516	$24,346,470	$88,770,986

Based on these results I concluded that distribution revenues would need to increase by 16.1%, on average (the "System-Wide Increase"), in order for the Company to achieve its revenue target, as shown at Lines 88–89 of RATES-5.

Q. Did you use this result as the basis for the estimation of class-specific revenue targets?

A. Yes. I determined how much revenue would be generated by each class of customers at current rates, which is shown at Line 82 of RATES-5, and aggregated those revenues by customer class type, as shown at Line 83. Multiplying those results by 16.1% yielded the preliminary revenue target for each class grouping, which is shown at Line 89. As indicated, the total of the preliminary revenue targets for all the class groupings is equal to the Company-wide revenue target, $103.9 million.

Q. Did you make any additional adjustments?

A. Yes. In the course of conducting my analysis, it became clear that for certain rate classes, using these preliminary revenue targets without adjustment would create inconsistent bill impacts that conflicted with rate continuity objectives. For that reason, I reduced the targets for the residential classes and for one of the C&I (G-51) classes, including all the derivative classes (e.g. RLIAP and MEP variants). This adjustment is designed to promote consistency across the rate classes. This adjustment and the resulting preliminary class revenue targets are shown at Lines 91–96 of RATES-5. Because the adjustment is revenue-neutral, the total of the revenue targets for each of the class groupings remains the same, $103.9 million, after the adjustment is applied, as shown at Line 96.

Q. Why did you group the rate classes?

A. For two reasons. The first is that each of the MEP rates are a function of their corresponding standard rate. The same is true for the RLIAP rates, which are each a function of R-3 rates. Attempting to calculate changes to these rates separately could lead to unintended inconsistencies or changes in the relationship between the rates. The second reason for grouping the classes in this manner is that the marginal cost to serve each customer class is the same. In the case of the MEP rates, the only difference in costs compared to the equivalent non-MEP rates is the upfront interconnection costs that had historically been offset by the CIAC but that are now paid for via the premium added to the MEP rates. In the case of the RLIAP rates, there is no meaningful difference in the cost to serve customers R-4 and/or R-7 customers and the cost to serve customers in the corresponding, non-RLIAP classes.

Q. What did you do next?

A. I increased the existing customer charges by 16.1% as shown at Lines 98–100 of RATES-5. The increased rates generate approximately $31.6 million in revenues, meaning that the Company must recover approximately $72.3 million in volumetric revenues; see Lines 106–107 for details.

Q. Did you increase the volumetric rates by the same amount?

A. No, I did not. Although the system-wide increase and the adjustments I made for consistency described above were important inputs to my calculation of the volumetric rates, they were not the only factors. The revenue requirement that I calculated also accounted for the results of the MCS, from which I then developed volumetric rates.

Q. How did you account for the results of the MCS when calculating your volumetric rates?

A. I had previously calculated the increase in the revenue target for each class grouping, based on the System-Wide Increase, which is shown at Line 111 of RATES-5. I also calculated the increase in each class grouping revenue target implied by the results of the MCS, which is shown at Line 85. In order to move the Company's ratemaking inputs towards convergence with the MCS results, I adjusted the change implied by the System-Wide Increase based on the results of the MCS, subject to the constraint that only a 15% variance in the change to the total revenue target for each class grouping was allowed. . In all cases, the constraint bound, which is to say that the increase to the class grouping revenue requirement was either increased or decreased by 15%. Line 115 shows the preliminary result for each grouping.

Q. Why is it necessary to limit the adjustment to the revenue targets to less than the amount implied in the MCS?

A. To balance the competing interests of efficient rate design and rate continuity. As I explain previously in my testimony, the theory that pricing utility services at their marginal costs helps customers make more efficient decisions regarding their consumption of those services is well established. On the other hand, rate continuity is an important policy priority. A limited change that moves rates towards convergence with the utility's marginal cost of service without resulting in dramatic impacts to customer costs may accomplish both objectives.

Q. What did you do next?

A. The net effect of making the constrained adjustment to each class grouping was to create a set of revenue targets that would have resulted in the slight under-recovery shown at Line 118 of RATES-5. I therefore applied the adjustment shown at Line 119 to the target for each grouping in order to maintain revenue neutrality, the result of which was the new set of revenue targets that are shown at Line 120. From each of these I deducted the revenues expected from customer charges. The remaining amount, shown at Line 121, is the amount to be recovered by each grouping from gas sales at the applicable volumetric charges.

Q. How did you calculate the volumetric rates?

A. From the rates in the Company's currently effective tariff, I calculated the ratios of winter to summer and of headblock to tailblock rates for each class, which are shown at Lines

127–132 of RATES-5. I have assumed that those rations will not change. As a result, there is only a single set of rates for each class grouping that will simultaneously maintain those ratios, maintain the relationships between base and derivative rates (*e.g.* MEP rates 30% higher than standard rates and RLIAP rates 60% lower), and generate exactly the amount of revenue required to meet the revenue target. I used a "goal seek" algorithm to identify those rates, which are shown at Lines 135–139.[10]

Q. Did you validate whether your proposed rates generate the appropriate amount of revenue?

A. Yes. Lines 146–148 and Lines 162–165 demonstrate that these rates result in achievement of the revenue target for each class and for the Company as a whole.

Q. Please summarize your proposed rates.

A. The rates I propose are shown below.

Table 15. Proposed Distribution Rates

Class	Customer Charge *($/month)*	Winter Headblock *($/therm)*	Winter Tailblock *($/therm)*	Summer Headblock *($/therm)*	Summer Tailblock *($/therm)*
R-1	$17.99	$0.4137		$0.4137	
R-5	$23.39	$0.5378		$0.5378	
R-3	$17.99	$0.6520		$0.6520	
R-6	$23.39	$0.8476		$0.8476	
R-4	$7.20	$0.2608		$0.2608	

10 Specifically, for each rate class, I defined each of the volumetric rates as a function of the winter headblock rate, based on the ratios described above. The goal seek function then automatically tested different inputs to the winter headblock rate until it converged on a solution that resulted in revenues equal to the revenue requirement for each class grouping. The algorithm is a standard element of Microsoft Excel and the electronic version of RATES-5 that I have submitted with this testimony includes a macro to quickly execute the goal seek function in the same manner as I did, which will allow participants in this proceeding to replicate my calculations.

Class	**Customer Charge** *($/month)*	**Winter Headblock** *($/therm)*	**Winter Tailblock** *($/therm)*	**Summer Headblock** *($/therm)*	**Summer Tailblock** *($/therm)*
R-7	$9.36	$0.3390		$0.3390	
G-41	$66.71	$0.5433	$0.3650	$0.5433	$0.3650
G-44	$86.72	$0.7063	$0.4745	$0.7063	$0.4745
G-42	$200.14	$0.4999	$0.3331	$0.4999	$0.3331
G-45	$260.18	$0.6498	$0.4330	$0.6498	$0.4330
G-43	$858.91	$0.3126		$0.1429	
G-46	$1,116.58	$0.4064		$0.1858	
G-51	$66.71	$0.3408	$0.2216	$0.3408	$0.2216
G-55	$86.72	$0.4430	$0.2881	$0.4430	$0.2881
G-52	$200.14	$0.2926	$0.1948	$0.2120	$0.1205
G-56	$260.18	$0.3804	$0.2533	$0.2756	$0.1566
G-53	$883.94	$0.2092		$0.1003	
G-57	$1,149.12	$0.2720		$0.1305	
G-54	$883.94	$0.0900		$0.0488	
G-58	$1,149.12	$0.1170		$0.0634	

D. <u>Other Rate Changes</u>

Q. Are you proposing any other changes to rates?

A. Yes, I have calculated changes to charges that the Company uses to pass through to customers, specifically the charges associated with the Local Distribution Adjustment Clause ("LDAC") and the Cost of Gas ("COG") Clause that are described in the EnergyNorth tariff.

Q. What is the LDAC?

A. The LDAC allows the Company to recover a number of costs and expenses it incurs in the course of doing business. Among them is the cost of providing discounts to RLIAP customers.[11] Using the same information I used to calculate proposed distribution rates, I also calculated the change to the Company's cost to provide the RLIAP discount. The LDAC charge I propose is simply the existing LDAC increased by that amount.

Q. Please explain how you calculated the increase in the RLIAP cost.

A. As I explain above, the calculations shown in the "RATES-5 WP – RLIAP" workpaper indicates that the value of the RLIAP discount at current rates is roughly $2.2 million. The Company recovers the RLIAP discount from all customers on a volumetric basis. Based on total test year volumes, the current value of the RLIAP is $0.0123/therm (RATES-5 at Line 12). To measure the change that arises when distribution rates are increased, I re-calculated the value of the RLIAP discount using the rates I am proposing and determined that it increases to $2.6 million, or $0.0141/therm (Lines 156–157). The difference of $0.0019/therm (Line 159) is the basis for the increase in the LDAC. Current and proposed LDAC rates are provided in Attachment RATES-4 and summarized below.[12]

Table 16. Proposed LDAC Charge Update ($/therm)

	Current	Proposed
Residential	$0.0310	$0.0329
C&I	$0.0478	$0.0497

[11] See Section 17 at p. 32 of the EnergyNorth tariff for a detailed description of the LDAC.
[12] All customers, including those served under the MEP and RLIAP classes, pay the same LDAC charge, no discounting or premiums are applied. This is also true for the COG charge.

Q. Please explain your calculation of the increase in the COG charge.

A. Section 16 of the EnergyNorth tariff allows it to recover certain costs of service, including costs incurred for Liquid Propane ("LP") and/or Liquefied Natural Gas ("LNG") storage, the cost of bad debt, allowable working capital from demand- and commodity-related costs, and other administrative and general expenses through a COG charge that varies by season. Costs are recovered volumetrically based on Company sales volumes (transportation-only customers are excluded). LP and LNG storage costs are recovered through winter sales, all other costs are recovered based on annual sales. Costs for each category were calculated by Messrs. Simek and Sosnick and are described in the COS Studies. To calculate the change in the COG charge that arises from those costs, I reviewed data provided to me by the Company that details sales and transportation volumes for the 12 months ending June 2020, from which I was able to determine the relative contributions of sales and transportation service for each rate class for that period. I then applied those proportions to the test year volumes to estimate test year sales by rate class. My calculations are shown in the workpaper labelled "WP – RATES-6", which is provided with Attachment RATES-6. Using those data, I calculated that the COG charge would increase by $0.0023/therm for summer sales and decrease by $0.0019/therm for winter sales, as shown in RATES-6. The change in the COG provides the basis for the proposed COG charge. Separate charges are applied to residential, high load-factor, and low load-factor C&I customers. The proposed COG charge for each class is simply the seasonal charge adjusted by the amounts I calculated in RATES-6. The revised COG charges that result are shown below.

Table 17. Proposed COG Charge Update ($/therm)

	Current	Proposed
Residential *R-1, R-5, R-3, R-6, R-4, R-7*		
Winter	$0.2679	$0.2660
Summer	$0.3715	$0.3738
C&I Low Load Factor *G-41, G-44, G-42, G-45, G-43, G-46*		
Winter	$0.2734	$0.2715
Summer	$0.3786	$0.3809
C&I High Load Factor *G-51, G-55, G-52, G-56, G-53, G-57, G-54, G-58*		
Winter	$0.2734	$0.2715
Summer	$0.3786	$0.3809

E. <u>Rate and Bill Impacts</u>

Q. Have you calculated the impacts on average bills?

A. Yes, bill impacts by season for each non-MEP rate class are provided in Attachment RATES-8. Annual impacts are summarized below.

Table 18. Average Bill Impacts

R-1	9.9%
R-3	9.5%
R-4	6.2%
G-41	8.7%
G-42	7.6%
G-43	6.6%
G-51	8.8%
G-52	6.8%
G-53	5.7%
G-54	4.3%

Q. What is the basis for these bill impact estimates?

A. Bill impacts were calculated based on the proposed distribution rates as well as the proposed LDAC and COG adders shown in Table 16 and Table 17. Using that data I calculated average bills at the proposed rates based on the calculations of average customer usage for each class shown in the workpaper entitled "RATES-8 WP". Next, I developed estimates of average monthly bills, which were then aggregated on a seasonal and annual basis. Those results were compared to the same calculation conducted at the rates currently in effect, the only exception to which was my use of the Company's average actual COG rates for Winter 2019/20 rather than the Winter COG rate in effect at the end of the Winter period.

Q. Have you provided this information in any other format?

A. Yes. Attachment RATES-7 conducts similar comparisons at various usage levels for customers in each of the non-MEP Classes.

F. <u>Decoupling Issue</u>

Q. Earlier in your testimony you indicate that you have identified a problem with the Company's decoupling mechanism; please explain the issue.

A. The Company's decoupling mechanism establishes an earnings target that is based on a revenue per customer amount. Each year, the Company reports its customer count, from which the allowed earnings is calculated. That amount is then reconciled with the Company's actual earnings over the same period. The problem arises in the determination of the customer count. At present, actual customer counts are extracted from EnergyNorth's billing system, including customers who started or stopped service. All of the new and departed customers are identified, and adjustment is made that is conceptually similar to the EOY Adjustment I describe above, whereby the year's customer count is adjusted for customers who received service for only part of the year. The result is to effectively re-compute the Company's allowed revenues as if any customer who received service during the year, for no matter how long, received service for the entire year.

Q. Why is this problematic?

A. Because, when the Company experiences growth, such adjustments artificially inflate revenues for no clear reason. Applying certain adjustments like the EOY Adjustment to billing determinants for ratemaking purposes may be reasonable insofar as doing so captures prospective impacts from changes that occurred during a test year which may affect the entirety of future years. Such adjustments are forward-looking since their intent is to develop assumptions that are expected to provide a just and reasonable basis for calculating rates in the future. The decoupling true-up, on the other hand, is intended to be backward-looking. Its purpose is to determine how much revenue the Company actually earned in a given year and reconcile those earnings to an amount based on its number of customers during the year.

Q. What are some of the risks that arise from this circumstance?

A. During periods of growth, the Company may be less able to achieve its authorized returns since its revenues could be overstated for decoupling purposes. EnergyNorth may also have less incentive to grow its customer base if doing so creates unintended impacts on earnings.

Q. Do you recommend a solution?

A. The reconciliation should be based on unadjusted actuals. Doing so would inherently recognize, among other things, that customers who received service for only a portion of a year only contributed to the Company's earnings for that same portion of that year. The data from EnergyNorth's billing systems that is currently used for the annualization adjustment can instead be used to generate a customer count that includes fractional customers whose contribution to the total count is a function of how long they took service for the year. For example, a customer who received service for exactly half the year would count as 0.5 customers.

Q. How do you recommend that the Company proceed?

A. I recommend that the Commission direct the Company and the parties to this proceeding to discuss revisions to the decoupling mechanism that avoids this distortion with the aim of developing an acceptable modification to the decoupling mechanism that can be filed with the Commission.

Q. Does this conclude your testimony?

A. Yes, it does.

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