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

MATTHEW J. DECOURCEY

November 27, 2019

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

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 for 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 like 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, 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 customers; however, for purposes of this proceeding, that cost is excluded from the MCS since 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 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 Commission has recognized the appropriateness of using marginal costs for purposes of utility ratemaking in numerous proceedings, including the Company's most recent gas distribution case, which was Docket No. DG 17-048.

B. MCS Methodology

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 DG 17-048. The study can be envisioned as being 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 2–8 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 each of 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 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:

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

[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. 189, the most recent available, of the Handy-Whitman Index of Public Utility Costs.

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 general method I have adopted is widely accepted. Regression analysis is widely used in New Hampshire and elsewhere for marginal cost studies for gas and electric utilities, including in the Company's most recent distribution rate case before the Commission. 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 "correct" sign. In this case, that means that all of the coefficients should be positive. *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 the incorrect (negative) sign, a low R-squared, 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 incremental demand; (Item 3) marginal costs of extending mains to incremental 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 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 their engineering data, the Company determined that the cost estimates and allocation to pressure support used for the MCS in its last distribution rate case 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 3.7% to account for three years of inflation between 2016 and 2019, which rate I determined by reviewing the U.S. Bureau of Economic Analysis's Gross State Product Implicit Deflator, was most recently published in August 2019. The result is a marginal unit cost estimate for production plant to maintain pressure support of $58.10/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 2019 to 2029 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 $76.40/dth of incremental design day demand.

Q. How did you estimate Item 3, the marginal cost of mains extensions to meet serve 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 approximately $964.65/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 $47.87/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 serve 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 an incorrect (negative) sign, so I rejected it and instead estimated the marginal cost using EnergyNorth's historical average production cost, which I determined to be $13.13/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 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 the Company provided. Because the resulting regression equation had an incorrect sign and a low R-squared, 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 $64.72/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 to total costs of each class, as shown at page 3 of Attachment MCOS-3. The resulting marginal costs 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	$60.79
R-3, R-4	$60.79
G-41	$65.78
G-42	$122.80
G-43	$273.30
G-51	$207.58
G-52	$125.99
G-53	$585.92
G-54	$290.94

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 between customer count and Accounting and Marketing expense, I chose to base my estimate of the marginal cost for that category of $65.77/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 A&G expense, (b) non-plant-related A&G expense, (c) 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 0.62% of the total utility plant cost. I conducted similar analyses for each of the other loading factors, in the completion of which I compared non-plant A&G expense to adjusted O&M, materials & supplies 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	$0.0062	/$ of utility plant
Non-plant related A&G expense	$0.6525	/$ of adjusted O&M
M&S and prepayments	$0.0131	/$ of utility plant
General Plant	$0.0551	/$ 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 is the initial cost 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 Fixed Carrying Charge Rates ("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 is 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 approach is consistent with the Company's most recent MCS in 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 MJD-5.

C. MCS Results

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 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	$2,183	$121	$2,304	2.2%
R3, R-4	$53,434	$15,107	$68,542	66.5%
G-41	$6,735	$6,600	$13,336	12.9%
G-42	$1,741	$7,858	$9,599	9.3%
G-43	$148	$2,404	$2,552	2.5%
G-51	$2,402	$496	$2,898	2.8%
G-52	$481	$1,085	$1,566	1.5%
G-53	$202	$1,195	$1,397	1.4%
G-54	$82	$827	$909	0.9%

III. RATE DESIGN

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 *first*, describe the data provided by the Company indicating its test year sales and customer counts for each class; *second*, explain the analysis I undertook to develop new rates for each of EnergyNorth's customer classes, *third*, summarize the impact of the proposed rates upon customer bills for each rate class, and *fourth*, describe an issue with the decoupling mechanism mentioned above and propose a solution.

A. Test Year Revenue Reconciliation

Q. Have you prepared a test year revenue reconciliation?

A. Yes, a revenue reconciliation is provided as Attachment RATES-1.

Q. What is the purpose of the revenue reconciliation?

A. There are two primary purposes of the reconciliation. The first is the calculation of the appropriate revenue baseline that will be used to calculate the system revenue deficiency, subject to certain adjustments. As shown at page 2, line 25 of RATES-1, the Company's billing data indicates that the unadjusted revenues for the test year were $86,813,681. The second purpose of the reconciliation is to validate that amount through a recreation of revenues using test year billing determinants and billing rates. As shown at page 2, line 50 of RATES-1, the results of that calculation indicate unadjusted test year revenues of $86,836,186, a difference of less than 0.03%.

B. Billing Determinants

Q. Were the revenues and sales volumes shown in RATES-1 adjusted for the rate design calculation?

A. Yes, they were. Volumes and/or revenues were adjusted to normalize for weather, to adjust for calendar month accounting, to reflect a change in rates during the test year, and to account for an adjustment made related to recovery of the cost of the low income discount through the Residential Low Income Assistance Program ("RLIAP") portion of the LDAC.

Q. Please explain the weather normalization adjustment.

A. It is generally accepted practice in New Hampshire and elsewhere to set rates using billing determinants that are normalized rather than actuals. Sales for a gas utility are sensitive to weather – generally speaking, the colder it is, the more gas the utility will sell. Thus, normalized sales and revenues are those that would likely have been realized during some period, based on historical relationships between sales and weather, had the weather been normal for that period, holding all other factors constant. Normalizing the determinants allows the inputs to the rate analysis to better reflect the sales and revenues the Company would be likely to achieve in a normal year.

Q. How did the Company normalize the data for weather?

A. The sales data were normalized in the same manner as in DG 17-048. The Company determined that in some winter months in the test year, sales were higher than normal due to variations in weather while in other months they were lower. Specifically, sales were higher than normal in November 2018 and January 2019. As such, a reduction in sales volumes for those months was made. In December 2018, February 2019, March 2019, and April 2019, sales were lower than normal and an upward adjustment to volumes was made. In the aggregate, total sales were higher than normal and the company made a total downward adjustment of 1,001,772 therms to test year volumes. The normalization calculations are shown in Attachment RATES-2. Note that separate adjustments are made to head block and tail block volumes; the total adjustment is the sum of the adjustment made to headblock volumes, shown at page 6, line 25 of RATES-2, and the adjustment to tail block volumes, shown at line 50 of the same page. As shown in

Attachment RATES-3, page 2, line 50, the total impact on revenues from the weather normalization was $383,623.

Q. Which base rates were used for the calculation of the weather-normalized revenues?

A. The applicable incremental rate for each class was used. That is to say that the rate used in the calculation is the rate that the customer paid for their last dth of consumption. EnergyNorth's tariff specifies differentiated rates for certain Commercial & Industrial ("C&I") customers based on usage levels, which it refers to as head blocks and tail blocks. A head block consists of a defined quantity of gas consumed in a month for which the customer is charged a set volumetric rate. If the customer exceeds that usage, it is charged the tail block rate for the remainder of its usage in that month. Thus, the marginal rate for residential customers is the same regardless of consumption and, for C&I customers, is dependent on whether monthly consumption exceeds the head block limit. This approach is consistent with the one used in the Company's last several rate cases.

Q. Given that the Company has a revenue decoupling mechanism, is weather normalization necessary?

A. Yes, it is. As I explain above, one of the objectives of the ratemaking process is to encourage consumers to make efficient decisions regarding their gas consumption, an objective that is supported by establishing rates that change in ways that are predictable and understandable. If the Company were to set rates based on a test year that did not reflect normal conditions, consumers' total cost of gas would change via an adjustment made in the decoupling mechanism, even if all other factors were held constant. The result could be confusing to customers and may distort the price signals that support their efficient consumption decisions. In the Company's last rate case, the Commission recognized this fact and allowed the Company to normalize the billing determinants for weather at the same time EnergyNorth's decoupling mechanism was approved.

Q. Please explain the calendar month adjustment.

A. The Company's billing cycles are not based on calendar months; however, it has chosen to re-cast its cycle-based, normalized revenues on a calendar basis because doing so is more consistent with generally accepted accounting principles, is consistent with its past practices in proceedings before the Commission, and because calendar month data permits easier and simpler calculation of revenues in the event of rate changes since such changes occur at the start of a calendar month. The adjustment is calculated as the difference between actual therms billed each month for each rate class and the calculated volumetric billing determinants for each month for each rate class. As shown at page 3, line 50 of RATES-2, the calendarization adjustment was 165,457 therms. The revenue impact of the calendarization adjustment is a decrease of $385,157.

Q. Please explain the rate change adjustment.

A. Because rates changed during the test year, an adjustment is required to capture revenue levels that would have been persisted had End of Year ("EOY") rates been in place throughout that period. The EOY adjustment is a revenue reduction of $209,058, as shown at page 3, line 50 of RATES-3.

Q. Please explain the adjustment related to recovery of the cost of the low-income discount through the LDAC.

A. Previously, the Company had been recording the RLIAP recovery as a reduction to expense related to the Cost of Gas ("COG"), rather than as revenues. When calculating revenue requirements, accounts related to COG are removed from the calculation. As a result, RLIAP revenues were being excluded from the revenue requirement and as such, need to be added back as an adjustment. The value of the adjustment is $2,166,034.

Q. Were there additional adjustments made in the Company's last rate case that are not necessary in this proceeding?

A. Yes. In calculating the normalized billing determinants and revenues in DG 17-048, the Company made adjustments to account for the acquisition of the assets of the Concord Steam Corporation ("Concord Steam") and for revenue from EnergyNorth's Cast Iron/Bare Steel ("CIBS") program. Neither are required in this proceeding.

Q. Why is an adjustment to account for Concord Steam not required?

A. At the time DG 17-048 had been filed, the Company had agreed to purchase certain assets of Concord Steam but had not yet completed the transaction. The purchase was expected to result in the closing of Concord Steam's plant, which would require most of its customers to switch to natural gas for space heating purposes. To account for this effect, the Company made an adjustment to reflect the loss of sales to the plant and an offsetting adjustment to reflect the increase in sales to the customers who were switching. Because that transaction was completed prior to the test year in this proceeding, all of its effects are captured in the normalized test year determinants and revenues, and no adjustment is required.

Q. Why is an adjustment to account for the CIBS program not required?

A. Pursuant to the Commission's Order No. 25,918, the Company implemented new base rates for recovery of costs approved under the CIBS program on July 1, 2016, which fell in the middle of the test year for DG 17-048, necessitating a pro forma increase to reflect the revenues the Company recovered in the second half of the test year. In this proceeding, given that the start of the teat year is July 1, 2018, those revenues are already included in test year revenues and no adjustment is required.

Q. Please summarize the Company's weather-normalized revenue at current rates.

A. The Company monthly weather normalized base revenues for the test year, which includes each of the adjustments indicated above, is $88,541,863, as shown below:

Table 6. Summary of Revenue Adjustments

Base Revenues	$86,813,681
Weather normalization adjustment	($385,157)
Calendarization adjustment	$156,363
EOY adjustment	($209,058)
RLIAP-LDAC adjustment	$2,166,034
Adjusted revenue	$88,541,863

For purposes of rate the rate design analysis, revenues were assumed to be $88,384,954, a difference of less than 0.2%, based on the calculations using the billing determinants shown in the workpaper "RATES- 5 WP – Determinants" attached to RATES-5.

C. Rate Calculations

Q. Is the Company proposing any changes to the design of its rates?

A. No, it is not. I therefore held the rate design constant for all classes and calculated the increase for each that would be required to meet EnergyNorth's revenue requirement.

Q. Please briefly summarize your approach to the calculation of the rates for each class.

A. The design of the rates comprised three steps. *First*, I calculated the revenues that would be earned in each class based on the test year billing determinants I was provided by the Company and the rates currently in effect. I also calculated the amount of revenue lost by the Company for providing service at discounted rates to customers in the R-4 and R-7 rate classes. *Second*, I estimated a revenue requirement for each class using the results of the MCS and the Functional Cost of Service ("FCOS") study described in Mr. Sosnick's testimony. *Third*, I calculated the increase in rates that would be required to achieve the revenue requirement for each class.

Q. Please describe your calculations of test year revenues at current rates.

A. Using the normalized billing determinants provided by the Company, I developed a pro forma that indicates the amount of revenue it would earn from sales to each class of customers at current rates. Data I used included customer count and seasonal volumes sold for customers in each class, differentiated by usage blocks.

Q. Does the revenue pro forma include an adjustment for revenues lost on sales in rate classes R-4 and R-7?

A. Yes, it does.

Q. Please explain the need to adjust for sales to customers in the R-4 and R-7 classes.

A. The Company provides gas to its customers in the R-4 and R-7 rate classes at a 60% discount compared to standard rates under the RLIAP. During the test year, there were roughly 35,000 customers receiving gas under these tariffs, the vast majority of which receive service under the R-4 class, to whom the Company made total sales of approximately 4,650,000 therms, on a normalized basis. This indicates that the total discount provided to customers under the two RLIAP tariffs is approximately $2.2 million, inclusive of volume and customer charges. The cost of the discount to these customers is borne by customers in each of the Company's rate classes on a pro rata basis and is therefore included as an adjustment to the revenue requirement to be allocated to each class, as described below. My calculations related to the RLIAP discount are shown in the workpaper entitled "RATES-5 WP – RLIAP" attached to RATES-5.

Q. Have you prepared an Attachment that shows the revenue pro forma?

A. Yes, I have. Sections A and B of Attachment RATES-5 show the revenue proforma and billing determinants by class. The RLIAP discount is shown at line 11.

Q. How did you account for the Company's Managed Expansion Program ("MEP") customers?

A. MEP customers are new customers of the system who, under existing tariffs, are changed a 30% premium over standard rates for the class to which they would otherwise be assigned. Thus, each of the Company's non-MEP rates has a corresponding MEP rate. Table 7 shows the correspondence between each of the Company's non-MEP rate and its MEP rate:

Table 7. MEP Rate Classes and Corresponding Non-MEP Rate Classes

Non-MEP Rate	MEP Rate
R1	R5
R3	R6
R4	R7
G41	G44
G42	G45
G51	G55
G52	G56
G53	G57
G54	G58

For each pair of rate classes shown above, I calculated a single revenue requirement which I compared to total revenues from sales to customers for each of the two classes (for example, G41 and G44 were combined in this manner, as were R-1 and R-5, etc.). The ensuing calculations, which I describe below, determined how much the revenue from the combined class would need to be increased, based on sales to a combined number of customers, to meet the revenue requirement. Based on those results, I was able to calculate separate rates for each pair by holding the 30% premium constant; in other words, R-5 rates would remain 30% higher than R-1 rates, G-44 rates would remain 30% higher than G-41 rates, and so on.

Q. What is the total revenue requirement that the Company's base rates are designed to recover?

A. Base rates were designed to recover $99,505,920, as shown at Line 45 of Attachment RATES-5. This is the amount equal to the delivery service revenue requirement of approximately $95.5 million identified by Mr. Sosnick in his FCOS testimony, along with three adjustments.

Q. Please explain the adjustments.

A. The revenue requirement was decreased by $1,157,325 to adjust for other revenues earned by the Company, increased by a total of $2,165,405 to recover the cost of the RLIAP discount, and increased by 3,030,911 for the step adjustment described by Mr. Sosnick and Mr. Simek. The adjustments are summarized below:

Table 8. Adjustments to Revenue Requirement

Adjustment	Amount	Line Reference in RATES-5
Revenue requirement from FCOS	$95,466,940	38
Other Revenue	($1,157,325)	39
RLIAP discount	$2,165,405	11 or 42
Step Adjustment	$3,030,911	44
Total	$99,505,920	45

Q. How was the adjusted revenue requirement allocated to each class?

A. I calculated a preliminary revenue requirement for each class based on the results of the MCS study. The capacity-related and customer-related marginal costs of service for each class are shown in Attachment MCOS-6 at page 3; the total marginal cost of service is $103,102,407, which is higher than the revenue requirement. Accordingly, a uniform adjustment is made to each type of marginal cost for each class, an approach known as the Equi-Proportional Method ("EPM"), to reduce the marginal cost results to equal the adjusted revenue requirement. The EPM adjustment was 3.49%. The result is a set of adjusted marginal cost for each class such that the total marginal annual revenues are equal to the adjusted revenue requirement shown in Table 3.

Q. How is the revenue requirement per class calculated?

A. As shown at Lines 60–66 of Attachment RATES-5, I calculated a revenue pro forma for each rate class, including revenue from sales to MEP customers, based on current rates. As shown at Line 65, Column W, the total expected revenue is approximately $86.4 million. The adjusted revenues are equal to approximately $99.5 million, as shown at Line 55, Column W, indicating that a system average increase of 15.2% is required to achieve the revenue target. I therefore set the revenue target for each class at 115.2% of its pro forma revenues, as shown on Line 72.

Q. Is this approach consistent with the Company's previous practices before the Commission?

A. Yes, it is. In its request for a rate increase in DG 17-048, the Company initially requested an increase in rates for residential customers of more than 30% and much smaller increase for C&I customers (less than 20%), based largely on the results of the MCS it had developed for this proceeding. The rate design that was ultimately approved by the Commission in that proceeding resulted in average percentage increases to rates for the residential and C&I classes that were nearly identical. The results of the MCS that I conducted indicates similar potential increases (as shown at line 69 of Attachment RATES-5) as were indicated in DG 17-048; based on the final result of that proceeding, I applied the system average increase uniformly to all classes instead of differentiating increases among the classes based on the results of the MCS.

Q. Please explain how you determined the increase in customer charges.

A. For each class, the customer charge was increased by the system average increase of 15.2%. I then determined how much revenue this would generate, including revenue from sales to MEP customers, by multiplying the proposed customer charge to the test year customer counts, as shown at Line 51 of Attachment RATES-5. The difference between this revenue and the class revenue requirement is the amount of revenue that needs to be recovered through volumetric rates.

Q. How were the volumetric rates determined?

A. For each class, the volumetric rates were increased such that the total volumetric revenues were equal to the difference between the revenue requirement and customer charge revenue for each class. In setting the volumetric rates, I sought to promote rate continuity and to implement rates that result in relatively consistent bill impacts at high and low levels of use. For those classes that have different rates for head blocks and tail blocks, I retained the relationship between the two, setting the tail block rate at 85% of the average volumetric rate. The resulting volumetric rates are shown at Lines 103–107 of Attachment RATES-5.

Q. Have you prepared a proof of the revenues that the proposed rates produce?

A. Yes, I have. Lines 126 to 134 calculate the revenues the proposed rates would produce based on the test year billing determinants. They produce $99,505,920 in revenue, an amount equal to the revenue requirement.

D. Rate and Bill Impacts

Q. Please summarize your proposed rates.

A. Table 9, below, shows the current and proposed customer charge for each class along with the change, expressed on a percentage basis, for each:

Table 9. Comparison of Current and Proposed Customer Charges

	Current	Proposed	% Increase
R-1	$15.20	$17.30	13.85%
R-3	$15.20	$17.30	13.84%
R-4	$6.08	$6.92	13.84%
G-41	$56.36	$64.15	13.82%

	Current	**Proposed**	**% Increase**
G-42	$169.09	$192.46	13.82%
G-43	$725.66	$825.93	13.82%
G-51	$56.36	$64.15	13.82%
G-52	$169.09	$192.46	13.82%
G-53	$746.81	$850.00	13.82%
G-54	$746.81	$850.00	13.82%

Table 10 shows a comparison of the volumetric rates. For the residential classes, rates are the same for all consumption levels and for all seasons. Rates for classes G-41, G-42, G-51, and G-52 are differentiated by head block and tail block but not by season. Rates for classes G-43, G-53, and G-54 are differentiated by season but not by block.

Table 10. Comparison of Current and Proposed Volumetric Rates

	Current	**Proposed**	**% Increase**
R-1	$0.3786	$0.4310	13.84%
R-3	$0.5569	$0.6338	13.81%
R-4	$0.2228	$0.2535	13.79%
G-41			
Head block	$0.4621	$0.5260	13.83%
Tail block	$0.3104	$0.3533	13.82%
G-42			
Head block	$0.4202	$0.4783	13.83%
Tail block	$0.2800	$0.3186	13.80%
G-43			
Winter	$0.2583	$0.2940	13.82%
Summer	$0.1181	$0.1344	13.83%
G-51			
Head block	$0.2785	$0.3170	13.83%
Tail block	$0.1811	$0.2061	13.79%
G-52			
Head block winter	$0.2392	$0.2722	13.81%
Tail block winter	$0.1593	$0.1813	13.83%

	Current	Proposed	% Increase
Head block summer	$0.1733	$0.1972	13.81%
Tail block summer	$0.0985	$0.1121	13.80%
G-53			
Winter	$0.1672	$0.1903	13.79%
Summer	$0.0802	$0.0913	13.83%
G-54			
Winter	$0.0638	$0.0726	13.74%
Summer	$0.0346	$0.0394	13.94%

Q. Do these rates provide for recovery of the discount provided to customers in the R-4 and R-7 rate classes?

A. No, they do not. Those revenues will be recovered through the Company's LDAC mechanism.

Q. Have you calculated the RLIAP component of the Company's LDAC mechanism?

A. Yes, I have. As shown at Line 120 of Attachment RATES-5, the total discount provided to customers under the RLIAP for the test year is $2,494,205. To calculate the RLIAP component of the LDAC, that amount is divided by the total delivery quantity billing determinants, 178,268,115 therms, as shown at Line 26 of RATES-5, for a result of $0.014 per therm.

Q. Have you provided a proof of the revenues that the proposed rates produce?

A. Yes. The calculations, which are shown at Lines 137–139 of Attachment RATES-5 show that the proposed base rates, including the RLIAP revenues, produce the base requirement of $99,505,920.

Q. Have you prepared a proof of the revenues that the proposed Indirect Gas Cost rates produce?

A. Yes. Attachment RATES-6 shows the revenues that will be produced by the indirect gas costs.

Q. Have you prepared a bill impact analysis?

A. Yes, I have. Attachment RATES-7 shows monthly bill impacts by class and season across a wide range of consumption levels. For each class, I estimated the total bill at each consumption level, inclusive of customer and volumetric charges, using both rates currently in effect and the proposed rates I describe above. I have also prepared a separate attachment, RATES-8, that shows bill impacts using class average usage in the same format used in Cost of Gas Compliance filings before the Commission.

E. Decoupling issue

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

A. Under the Company's decoupling mechanism, EnergyNorth is assumed to earn revenues based on the number of customers it has in each class at the end of each year. Using billing actuals, a per-customer revenue estimate is developed for each class. Then, an adjustment is made to effectively re-compute the Company's revenues as if its year-end customers had been under service for the entire year.

Q. Why is this problematic?

A. Because in recent years the Company's customer base has been growing. As a result, it has tended to add customers over the course of the year. This means that by the end of each year, there are a significant number of customers that have not served by EnergyNorth for the full year, and some have only been served by a small portion of the year. In years in which the Company's customer count grows, this aspect of the decoupling mechanism therefore results in an overstatement in the Company's revenues because the calculations assume EnergyNorth has earned a full year's worth of revenue from the added customers, when in fact they have only generated revenue for the Company for however long they have been customers.

Q. What do you recommend?

A. I recommend that the Commission Staff and the Office of the Consumer Advocate engage the Company in discussions of a decoupling mechanism that avoids this distortion. Give that a number of workable alternatives exist, it seems likely that a mutually agreeable solution that better reflects the Company's revenues each year can be identified.

Q. Is the Company requesting recovery of the revenues lost as a result of the customer count distortion?

A. No, it is not, EnergyNorth's only focus is addressing this issue on a going-forward basis.

Q. Does this conclude your testimony?

A. Yes, it does.

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