EXHIBIT
#14
DG 17-048

STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

Docket No. DG 17-048

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Distribution Service Rate Case

TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of the

STATE OF NEW HAMPSHIRE

OFFICE OF THE CONSUMER ADVOCATE

November 30, 2017

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Q. Would you please state your name and address?

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida.

Q. Please briefly describe your occupation and qualifications.

A. I am employed as a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation. I received a Bachelor of Arts degree in Economics from the University of South Florida, and both a Master of Science in Economics and Doctor of Philosophy in Economics from Florida State University.

Over the course of more than 40 years, I have been actively involved in more than 400 regulatory dockets, involving electric, natural gas, and other utilities. I have presented expert testimony on more than 250 occasions, before federal regulatory agencies, various state courts, and regulatory commissions in 40 states, two Canadian provinces, and the District of Columbia. Most of this work has been performed on behalf of regulatory commissions, consumer advocates, and other government agencies involved in regulation. However, our firm has also worked for other types of clients as well, including large industrial consumers and non-profit entities like the AARP and the North Carolina Sustainable Energy Association.

Q. Have you prepared an appendix that provides some additional details concerning your qualifications?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes. I prepared Exhibit___(OCA-2), consisting of two schedules. These schedules were prepared under my supervision and are true and correct to the best of my knowledge.

Q. What is your purpose in making your appearance at this hearing?

A. My firm has been retained by the New Hampshire Office of the Consumer Advocate (OCA) to assist in preparing and presenting evidence with respect to the pricing and decoupling proposals submitted by Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberties Utilities ("EnergyNorth" or "the Company").

I will primarily be responding to the pricing proposals set forth in the testimony of David B. Simek and Gregg H. Therrien, and the revenue decoupling proposal set forth in separate testimony submitted by Gregg H. Therrien. I will also discuss the marginal cost study described in the testimony of Melissa F. Bartos, and the functional (embedded) cost study described in the testimony of David A. Heintz.

Following this introduction, my testimony has five major sections. In the first section, I discuss the Company's revenue decoupling proposal. In the second section I discuss the Company's proposed revenue allocation and rate design. I give particular attention to the EnergyNorth's proposals to increase the fixed monthly charges that are paid by all customers regardless of how much energy they consume. In the third section I define various economic concepts, including marginal costs, joint costs and sunk costs and the difference between the long-run and the short-run. I then explain how these concepts relate to the way prices are established in unregulated markets, and the rate design issues in this proceeding. In the fourth section, I discuss the Company's marginal cost study. I note some serious flaws in the study and recommend that the Commission not rely on the study results as submitted. In the fifth section I summarize my recommendations.

I. THE COMPANY'S DECOUPLING PROPOSAL

Q. Can you briefly describe the Company's decoupling proposal?

A. Yes. The Company is proposing a revenue per customer decoupling mechanism that will eliminate the traditional link between sales and revenues. Normally, when customers use more energy, revenues and earnings increase; when they use less energy, revenue and earnings decline. This normal linkage will be broken by creating a mechanism that periodically adjusts rates to cancel out the impact of usage changes.

> EnergyNorth proposes to implement rate design measures that will "decouple" the traditional connections between the volume of gas that EnergyNorth delivers to its customers and its revenues and earnings.[1]

If it is accepted by the Commission, this mechanism will disassociate EnergyNorth's financial performance from the amount of gas it delivers during any given month or year. This will tend to stabilize its revenues, improve earnings, and reduce the frequency rate cases. While these are significant benefits from a stockholder perspective, the Company did not dwell on these aspects of its proposal. Instead, its testimony primarily focuses on the way decoupling will reduce the disincentive for it to promote energy conservation.

> By eliminating the link between customer consumption and Company earnings, decoupling removes the disincentive

1 Direct Testimony of Gregg Therrien, Page 4.

> for utilities to promote conservation and energy efficiency programs. Companies that have implemented decoupling are no longer caught between promoting conservation (that reduce sales) and growing revenues (by increasing sales). Breaking the link between utility sales and revenues is the best way to promote conservation activities fully and freely.[2]

Q. Is decoupling related to the existing LRAM?

A. Yes. Decoupling would replace the LRAM, which serves a similar purpose. The LRAM was recently added to the Company's tariff pursuant to Order 25,932, which implemented the Energy Efficiency Resource Standard.[3] The parties to that proceeding sought to reduce the incentives utilities have to encourage increased energy usage, or to discourage energy conservation.

> Utilities should have the incentive and initiative to continue implementing robust energy efficiency programs effectively, to the mutual benefit of ratepayers, shareholders, and the natural environment of the state.[4]

Although the LRAM and decoupling were viewed as alternative mechanisms for achieving similar goals, full consideration of decoupling was postponed until future rate cases.

> [A] targeted lost revenue adjustment mechanism (LRAM) or decoupling may be used to compensate utilities for lost revenues associated with energy efficiency.
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> …
>
> Because of Commission policy requiring the consideration of decoupling only within the context of a rate case, Staff recommended the adoption of an LRAM for the initial three-

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2 Ibid, pp. 5-6.
3 New Hampshire Public Utilities Commission, Order 25,932, August 2, 2016 ("Order 25,932").
4 Ibit, p. 9.

year period, to be replaced thereafter by a decoupling mechanism.[5]

Q. How does decoupling relate to energy conservation?

A. Under traditional ratemaking, utilities benefit when customers use more energy, since this leads to increased revenue in the short-run and a larger rate base and increased earnings in the long-run. The LRAM alleviates these perverse incentives, but only with respect to specific energy efficiency programs and initiatives. Decoupling achieves a broader, more fundamental shift in incentives, because revenues become largely impervious to improvements in energy efficiency – including improvements resulting from tightened building codes, increased appliance standards, technology improvements, heightened awareness of greenhouse gas emissions, and other factors.

This broader scope is significant, because EnergyNorth can potentially influence the decisions by customers and the companies that construct new buildings concerning what insulation they install, what appliances they purchase, and what type of energy they use. Currently, EnergyNorth has an incentive to steer customers into the programs and initiatives included in the LRAM, rather than finding other ways to reduce their energy usage that are not tied to those specific programs.

Implementation of decoupling is often accompanied by a move away from high fixed customer charges, declining blocks, and other rate structures that create a

5 Ibid, p. 24.

disincentive for energy conservation.[6] For example, Pacific Gas & Electric (PG&E)'s move to decoupling included replacement of their fixed customer charge with a minimum monthly charge of three dollars. This makes sense, because decoupling provides the revenue stability that was one of the primary motivations behind high fixed customer charges and low volumetric rates, but without the harmful impacts on low usage customers and without the disincentive for energy conservation associated with high fixed charges and low volumetric rates.[7]

Q. How does decoupling affect customers?

A. As with the LRAM, the per-therm cost of gas delivery will increase under decoupling – assuming conservation efforts are resulting in a downtrend in energy usage per customer. However, decoupling is more symmetrical than the LRAM. For instance, if commercial and industrial usage increases due to an improvement in economic activity, the decoupling mechanism can lead to lower rates – a potential that does not exist with the LRAM.

When thinking about these issues, it is important to remember that distribution rate increases that occur under decoupling would eventually occur anyway, under

[6] Lazar, J. and Weston, F. Regulatory Assistance Project. Revenue Decoupling: A Guide to Theory and Application. Page 25-28. (June 2011) Available at: https://www.raponline.org/wp-content/uploads/2016/05/rap-revenueregulationanddecoupling-2011-04.pdf

[7] Migden-Ostrander, J. and Sedano, R. Regulatory Assistance Project. "*Decoupling Design: Customizing Revenue Regulation to Your State's Priorities*." Page 39. (November 2016) Available at: http://www.raponline.org/wp-content/uploads/2016/11/rap-sedano-migdenostrander-decoupling-design-customizing-revenue-regulation-state-priorities-2016-november.pdf (Stating "high fixed charges reduce the customer's incentive to conserve by increasing the payback period on energy efficiency and distributed generation investments" and "there is significant concern around the perverse subsidy that high fixed charges create in which a customer living in a large suburban home pays the same high monthly fixed charge as a low-income customer in a one bedroom or studio apartment, even though the costs for the utility to serve these customers are dramatically different in that the cost to serve customers in densely populated areas is generally less than in more spread-out residential neighborhoods."

traditional ratemaking, but with different timing. Regardless of whether or not decoupling is adopted, customers who reduce their energy usage will receive the benefit of a lower bill, and customers as a whole must still pay the fixed costs of the delivery system. The main difference is that rate adjustments necessitated by improved energy efficiency will occur in smaller, more frequent increments under decoupling.

That is not to say the only possible difference is one of timing. Under traditional ratemaking (without an LRAM or decoupling), customers can potentially benefit from the lag between the time when energy usage is reduced and when rates are adjusted. However, there are no "free lunches" under traditional rate base regulation. The more significant the improvement in energy efficiency, the more this lag will result in downward pressure on the utility's earnings. The resulting earnings erosion or attrition will motivate the utility to file more frequent rate cases, and it is likely to request a higher allowed return, larger allowances for "known and measurable changes," larger step increases, or other modifications to the traditional ratemaking process, in an effort to offset the earnings erosion problem. Regardless of whether or not these requests are accepted, the Commission will take steps to ensure that the Company has a reasonable opportunity to recover its costs and earn a fair return. And, regardless of the outcome, the increased frequency and complexity of the rate filings will increase rate case expenses – to the detriment of customers.

Q. Is the proposed decoupling mechanism an improvement over the existing LRAM?

A. Yes. It does a better job of removing the disincentive for EnergyNorth to encourage energy conservation, while eliminating the bias in favor of programs and initiatives included in the LRAM. With decoupling, the Company will have a more neutral outlook, since it will no longer be financially better off when customers channel their energy conservation efforts into specific programs included in the LRAM.

The proposed decoupling mechanism is also superior to the LRAM because it is symmetrical, while the LRAM is not. This means the potential exists for rate reductions due to decoupling – or, at a minimum, offsetting factors can potentially ameliorate the magnitude of rate increases necessitated by energy conservation. Decoupling allows revenue increases attributable to factors like changes in economic conditions and changes in the customer mix to offset revenue reductions attributable to energy efficiency programs. In contrast, the LRAM is narrowly focused on the impact of energy reductions due to specific programs, so there is no opportunity for offsetting factors to be considered.

Q. Please compare the approximate cost to ratepayers of EnergyNorth's LRAM arrangement against the approximate cost of the proposed decoupling mechanism.

A. Under the arrangement set forth in the April 2016 EERS Settlement Agreement and approved in Order No. 26,932, New Hampshire's investor owned utilities are compensated for their lost revenues attributable to their energy efficiency programs on a cumulative basis, with lost revenues accruing until the Company's next rate case, at which point the lost revenues are "reset to zero." *Order No. 26,932* at 30. The projected compensation associated with EnergyNorth's LRAM detailed in the 2016 EERS Settlement Agreement's "Gas Attachment B" assumes a four year timeframe before

EnergyNorth's first "reset to zero," and is summarized in the table on the left.[8] This can be compared to the approximate cost to ratepayers of the proposed decoupling mechanism. An estimate of that cost is provided by Greg Therrien for the period from summer 2011 to summer 2016 and summarized in the table to the right.[9]

Year	EnergyNorth Lost Base Revenue
2017	$143,274
2018	$480,808
2019	$841,813
2020	$1,226,837
Annual Average	**$673,183**

Year	Accrued Revenue Shortfall (Surplus)
Summer 2011	$224,260
Winter 2011-12	$3,969,815
Summer 2012	$446,708
Winter 2012-13	$156,006
Summer 2013	$162,960
Winter 2013-14	($3,479,131)
Summer 2014	($325,587)
Winter 2014-15	($2,761,837)
Summer 2015	($60,719)
Winter 2015-16	$3,687,185
Summer 2016	$85,642
Annual Average	**$382,781**

Q. Are there changes to the proposed decoupling mechanism that should be considered?

A. Yes. The Commission should consider two changes: linking the decoupling mechanism to total revenues, rather than revenue per customer, and having the mechanism operate on a "real-time" basis.

[8] Energy Efficiency Resource Standard Settlement Agreement. Gas Attachment B. Page 4 of 7. Available at: http://www.puc.state.nh.us/Regulatory/Docketbk/2015/15-137/LETTERS-MEMOS-TARIFFS/15-137_2016-04-27_STAFF_PARTIES_ATT_SETTLEMENT_AGREEMENT.PDF

[9] Therrien Direct Testimony at Bates 327. (Annual Average is the sum of the revenue column figures, divided by 5.5 years)

Q. Can you briefly elaborate on the difference between total revenue decoupling and revenue per-customer decoupling?

A. The key difference is whether revenues are pegged to the dollar amount needed to recover the revenue requirement, or whether that amount is converted into a per-customer equivalent. Under the latter option, total revenues will increase over time, as customers are added to the system. The Company explained its preference for the per-customer approach as follows:

> Adding new customers to the system involves incremental capital investment, which requires that the revenues from these new customers be necessarily retained by the Company to fund this new investment. Therefore, RPC RDMs are superior to Total Revenue RDMs for gas utilities, as new customer revenues are retained (at the system average RPC) to help cover the cost of the corresponding new investment. If a Total Revenue RDM is employed instead, then the LDCs incentive to add new customers is significantly diminished, as total revenues will remain unchanged while rate base grows.[10]

While I understand this reasoning, I don't find it persuasive. Total revenue decoupling would stabilize the Company's revenues at a level that has been reviewed and approved by the Commission, equal to the approved revenue requirement. In contrast, the per-customer approach results in a growing level of revenues (tied to the number of customers), which will become increasingly attenuated from the revenue requirement that was calculated and approved by the Commission in the most recent rate case.[11]

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[10] Direct Testimony of Gregg Therrien, Page 11.

[11] If the Commission chooses to rule in favor of the Company's revenue per customer proposal, they should consider requiring rate cases at least every five years, to ensure the gap between approved revenues and required revenues does not become excessive.

The increase in revenues that occurs with per-customer decoupling is not necessarily matched by an equivalent increase in the revenue requirement. In fact, some customers can be added to the system at locations where very little additional capital investment is required. There is no assurance that the increase in total revenues that occurs under the per-customer approach is fully needed, or that the resulting revenue growth will match any corresponding increase in the revenue requirement. It is also important to keep in mind that EnergyNorth has cash flows provided by depreciation and retained earnings that can be used to support new customer additions. If its capital additions exceed depreciation, and as a result its rate base increases (rather than decreases as depreciation accumulates), it will have the opportunity to recover the associated costs after they are reviewed and approved in a rate case.

As to the question of incentives, it is true that total revenue decoupling reduces the incentive to add new customers, but it will not completely eliminate that incentive. From a utility's perspective, growth is almost always viewed as desirable – particularly if it translates into an increase in the rate base. Growth in rate base supports growth in earnings per share and it makes a utility's stock more attractive from a stockholder perspective. There is every reason to anticipate that EnergyNorth will continue to pursue growth opportunities even if decoupling is approved on a total revenue basis. Admittedly, customer growth will not be as profitable as it would be under per-customer decoupling, but that does not mean growth will suddenly become unattractive, or negate the appeal of a larger rate base and increased overall scale of the Company's operations.

Q. Are there benefits to using total revenues rather than revenues per-customer?

A. Yes. This approach further increases revenue stability, which is appropriate since the Company's cost structure is tied to extremely long-lived investment. This approach also makes it easier to visualize and anticipate the impact of the decoupling mechanism – eliminating uncertainties related to unknown future fluctuations in the number of customers, the mix of different types of customers (e.g. high versus low-load factor commercial and industrial customers), and the impact of changing economic conditions on the usage of different size customers.

Q. Can total revenue decoupling be implemented in a way that provides additional funding for customer growth?

A. Yes. If the Commission decides that expansion into new areas should be encouraged and this type of customer growth should be more strongly supported, revenues from new customers that pay the "expansion rate" can be excluded from the total revenue decoupling mechanism. For instance, revenues from new customers who are required to pay the R-6 (Residential Heating-Expansion) delivery rates (which are 30 percent higher than existing R-3 Residential heating rates) could be excluded from both the "actual" and "target" revenues considered in the decoupling mechanism. This would effectively allow the Company to retain revenues from this category of customers, but not from new customers connected to parts of the system where the expansion rates do not apply.

Q. What do you mean by a "real-time" approach to decoupling?

A. Under the Company's proposal, annual calculations are performed that take into account the difference between actual billed revenues and the target level of revenues approved by the Commission. In a typical year, a large portion of this difference will be attributable to weather fluctuations; the remainder is attributable to energy conservation and other factors that influence usage.

> Between rate cases, sales vary because of weather, conservation, economic conditions, the deployment of DERs, and other factors. But weather is probably the largest of these, responsible for perhaps 80 percent of decoupling cost deferrals.[12]

With "real-time" decoupling, the difference between actual and normal weather is calculated and used to adjust bills as they are sent out each month.[13] This essentially eliminates any impact of weather on the annual decoupling calculations, confining those calculations to the more limited purpose of adjusting for any remaining difference between billed revenue and the targeted level of revenue. In effect, weather related usage fluctuations are decoupled in "real-time" each month, while all remaining usage fluctuations – including the downtrend in usage due to increased energy efficiency – are decoupled in the annual adjustment process.

Real-time decoupling can be implemented using either a per-customer or total revenue approach. In the former case, the review process would adjust for any

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[12] Migden-Ostrander, J. and Sedano, R. Regulatory Assistance Project. "Decoupling Design: Customizing Revenue Regulation to Your State's Priorities." Page 25. (November 2016) Available at: http://www.raponline.org/wp-content/uploads/2016/11/rap-sedano-migdenostrander-decoupling-design-customizing-revenue-regulation-state-priorities-2016-november.pdf

[13] Ibid.

discrepancies between billed revenues and the authorized level of revenues per-customer. In the latter case, the review process would adjust for any discrepancies between total billed revenues and authorized total revenues. Because the review process would not be focused on weather fluctuations, it could occur annually (rather than semi-annually, as proposed by the Company).

Q. Are there benefits to "real-time" decoupling?

A. Yes. This type of decoupling would achieve the same degree of revenue stability, while improving cash flow stability. This is a significant benefit for both the Company and its customers. Because weather-related decoupling would occur within the billing cycle, it will help smooth out bill fluctuations, making cash flows smoother and more predictable for both the Company and its customers.

Consider, for example, what would happen if November 2018 were unusually cold (compared to a normal November). Under EnergyNorth's proposal, this will result in a downward rate adjustment in order to achieve a stable level of revenues per customer – but the rate reduction won't occur until the 2019-2020 winter season – roughly a year after the cold snap. Under EnergyNorth's proposal, the offsetting bill credit appears a year later – far too late to help alleviate any cash flow problems customers suffer in the immediate aftermath of unexpectedly cold weather.

If a real-time decoupling mechanism were used instead, the rate reduction would be calculated and applied to the same billing cycle that includes the higher usage, and the downward rate adjustment or bill credit would appear in the exact same bill that includes the higher usage due to the abnormally cold weather. This is a very significant timing difference, which provides a very real, tangible benefit for customers – weather-related downward bill adjustments occur precisely when they are most needed.

If weather is abnormally mild, the corresponding bill adjustment works in reverse. With real-time decoupling, an upward adjustment occurs on the exact same bill that has a lower than expected level of usage. This timing is again ideal, because customers will be paying the slightly higher rate during a month when their usage is lower than normal. The end result is a slightly higher bill than if decoupling were not in effect, but that bill is still lower than it would have been if the weather had been normal. In contrast, under EnergyNorth's proposal, the upward rate adjustment appears on bills roughly a year later – at a time when the customer's bill might actually be higher than normal, due to colder than normal weather.

Not only does the "real-time" approach improve cash flows from the customer's perspective, it also improves cash flows from the Company's perspective. Since the Company's cost structure is largely fixed, while the weather fluctuates widely, this discrepancy forces it to maintain larger cash balances, or to engage in more intensive cash management efforts, than if its cash inflows were following a stable, easily predicted seasonal pattern based upon normal weather.

EnergyNorth's decoupling proposal does not improve this situation. Although it stabilizes revenues, it accomplishes this by accruing a "normal" level of revenues for each month; its actual incoming cash flow will not be synchronized with this stabilized revenue accrual. If the weather is mild, the Company will bill less than it accrues, then wait a year to implement the rate adjustment needed to actually receive the cash corresponding to its accrual. Conversely, if the weather is unusually cold, the Company will bill more than it accrues, keeping the excess cash until it adjusts rates downward approximately a year later. Weather fluctuations in both directions will continue to cause fluctuations in customer bills, and corresponding fluctuations in cash received from customers, which will not be synchronized to the Company's actual (relatively stable) cash flow needs.

In contrast, with real-time decoupling, cash flows will be synchronized with a stabilized, seasonal revenue pattern (customers will continue to see lower bills in the summer and higher bills in the winter, consistent with normal seasonal weather patterns). The timing of cash flows will be more predictable and improved for both the Company and its customers, regardless of how warm or how cold it is. With either approach to decoupling, rates will eventually be reduced if the weather is unusually cold, and they will eventually increase if the weather is unusually mild. The key difference is when this occurs. With the Company's proposed approach, weather-related rate adjustments occur long after an unusual weather event occurs, so the Company has to deal with the cash flow discrepancy during the interim. In contrast, with real-time decoupling, rate adjustments are simultaneous with weather-related usage fluctuations, thereby mitigating bill fluctuations and reducing the need to deal with cash flow discrepancies.

Since a real-time decoupling mechanism would provide substantial benefits to EnergyNorth, it would be reasonable for the Company to accept responsibility for most, if not all, of the administrative costs necessary to initiate this form of decoupling.[14]

[14] A preliminary vendor estimate provided to EnergyNorth and conveyed to the OCA via email on 11/27/17 suggests the up-front administrative costs associated with billing system upgrades is in the vicinity of $50,000 to $100,000. Amortized over three years, the mid-point of this estimate is equivalent to .015 cents per therm. To put this into

Q. Are there any other advantages to the "real-time" decoupling approach?

A. Yes. Customers will be more likely to understand and accept the mechanism if the portion that deals with weather-related fluctuations is separated from the portion that deals with energy conservation and other factors influencing usage. With the Company's proposal, weather-related rate adjustments will be combined with calculations related to other changes in usage, making it more difficult to explain the process to customers. Since weather fluctuations are very noticeable to customers, it makes sense to show them the weather-related rate adjustment immediately after the weather event – rather than a year later. Without the impact of weather fluctuations, the annual rate adjustment will be smaller, and it will be easier to explain to customers.

With the "real-time" approach, the annual true-up will compare billed revenues to authorized revenues. The resulting adjustment will ensure that actual revenues match the authorized level (either defined as the Commission-authorized total revenue or the authorized revenue per customer multiplied by the total number of customers). That annual discrepancy will be relatively small, since it won't be affected by weather fluctuations, and given its narrow focus it can be more readily explained as an "adjustment to match authorized revenues." Since the annual rate adjustment will be smaller under real-time decoupling, this approach also alleviates the need to impose a customer impact cap as suggested in Greg Therrien's Direct Testimony at Bates 324. If the Commission were to rule against real-time decoupling, they should strongly consider adoption of the customer impact protections suggested by Mr. Therrien. Additionally, since the magnitude of the annual adjustments will be smaller, and symmetrical, it would

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perspective, this is equivalent to 1 cent per month for a residential or small commercial customer using 800 therms per year.

be reasonable to further simplify the calculations by eliminating the need for a carrying charge associated with deferrals between true-up periods.

Q. Does real time decoupling shift risks associated with weather-related revenue fluctuations away from the Company toward customers?

A. No. With real-time decoupling risks are reduced for <u>both</u> stockholders and customers. Unexpected month-to-month and year-to-year fluctuations in customer cash-flows will diminish for customers just as they will diminish for stockholders – delivery bills will follow a predictable pattern that tracks normal seasonal patterns. For both sides of the billing process, real time decoupling eliminates the consequence of having a day or month that happens to be warmer or colder than that day or month would normally be. Removing this weather-related risk benefits both stockholders and customers.

Q. Do you have any other comments related to weather fluctuations?

A. Yes. New Hampshire has recently been experiencing mild winter weather, compared to years past, as shown below:

	Oct -Nov	Dec - Feb	Mar - May	Jun - Sep	Total
40 Yr	1,131	3,360	1,627	196	6,314
30 Yr	1,122	3,329	1,64o	183	6,273
25 Yr	1,127	3,327	1,646	173	6,272
20 Yr	1,124	3,317	1,642	174	6,257
15 Yr	1,119	3,345	1,624	166	6,254

	Oct -Nov	Dec - Feb	Mar - May	Jun - Sep	Total
10 Yr	1,111	3,338	1,578	166	6,193
5 Yr	1,103	3,276	1,576	158	6,112

It is not self-evident whether the recently milder weather has been entirely due to a sustained long term downward trend, or if cyclical factors or random fluctuations have been contributing factors. Regardless, the recent trend is not likely to suddenly reverse, or immediately revert to the colder weather that was experienced decades earlier. Given the above data, for ratemaking purposes, it would be reasonable to use a slightly shorter period of 25 years, and to give more weight to recent data than to older data. More specifically, I recommend giving full weight to the 2016 data, 24/25 weight to the 2015 data, 23/25 weight to the 2014 data, and continuing with that pattern through 1992, which should be given 1/25 weight. The resulting 25 year weighted averages are shown below:

	Oct -Nov	Dec - Feb	Mar - May	Jun - Sep	Total
25 Yr	1,114	3,327	1,623	168	6,233

Q. What would be the effect of this change?

A. It would have no impact on the calculated revenue requirement, but it would reduce the test year billing units. In turn, this would increase the calculated volumetric rates needed to achieve the revenue requirement. Finally, this change would make it more likely for the weather-related portion of any approved decoupling adjustments to fluctuate back and forth between positive and negative amounts, rather than being consistently biased in the positive direction. Stated another way, if decoupling is tied to "normal" weather that is colder than the milder weather that will actually be experienced during the next five to ten years, the decoupling adjustment will be systematically biased in the upward direction. This problem can be mitigated by using "normal" weather data that is more consistent with recent experience.

Q. Can you please summarize your recommendations concerning decoupling?

A. I recommend the Commission adopt a total revenue decoupling mechanism, in lieu of the existing LRAM. To the extent it is practical to do so, I recommend implementing this mechanism on a real-time basis, in conjunction with 25 year weighted average normal weather data for each billing cycle.

II. THE COMPANY'S RATE DESIGN PROPOSALS

Q. Before delving into the details of the Companies' pricing proposals, can you briefly explain your general approach to rate design?

A. Yes. Although rate design is more of an art than a science, it is nevertheless a very important part of the overall regulatory process. Designing rates is the stage where the Commission's decisions will have the greatest short-run impact on customers, and the greatest long-run impact on the Commission's overall policy goals. Rate design is not an area where deference should be given to the utility's preferences, or where “business as usual” is an appropriate philosophy. Instead, this is an area where the Commission should carefully weigh the pros and cons of the available options, and adopt that set of rates which it concludes will best serve the public interest.

The following discussion (in the context of electric rates) from page 5 of the Smart Rate Design for a Smart Future issued by the Regulatory Assistance Project in July 2015 is informative:

> Rate design is important because the structure of prices — that is, the form and periodicity of prices for the various services offered by a regulated company — has a profound impact on the choices made by customers, utilities, and other . . . market participants. The structure of rate designs and the prices set by these designs can either encourage or discourage usage at certain times of the day, for example, which in turn affects resource development and utilization choices. It can also affect the amount of electricity customers consume and their attention to conservation. These choices then have indirect consequences in terms of total costs and benefits to society, environmental and health impacts, and the overall economy.

Before going into greater detail concerning the current and proposed rate design, it is worth noting that the Commission faces a difficult task in designing rates, and I fully understand it must weigh the claims made by parties with widely varying perspectives. The Regulatory Assistance Project provides some useful perspective concerning the rate design process on page 8 of their July 2015 paper, Smart Rate Design for a Smart Future:

> A variety of stakeholder interests are at play in the debate over rate design, and finding common ground is not easy. Regulators face the task of fairly balancing concerns among utilities, consumers and their advocates, industry interests, unregulated power plant owners, and societal interests. The

> regulator accepting the charge of "regulating in the public interest" considers all of these values.

It is for this reason that I will explain my recommendations in considerable detail. EnergyNorth's revenue allocation and rate design proposals are closely linked to its marginal cost study, so I will define various cost-related terms and provide a strong theoretical foundation for my critique of the Company's cost claims.

There is one overarching theme that will run through all of this discussion: the appropriate relationship between prices and costs, and how that relationship impacts different types and sizes of customers. To advance the public interest, and be more consistent with how prices are set in competitive markets, I recommend recovering more of the revenue requirement through the volumetric rates. Throughout the remainder of my testimony I will provide detailed evidence supporting this recommendation, with the intent of providing the Commission with the tools it will need to evaluate the claims made by EnergyNorth and to chart a course that makes greater progress toward well-accepted public policy goals, without unduly impacting any group of customers.

A. Fixed versus Volumetric Cost Recovery

Q. What has EnergyNorth proposed with respect to its rate design?

A. The Company made a priority to increase its customer charges (the fixed monthly rate that applies regardless of how much or how little gas the customer uses). This priority is apparent from the workpapers it used to develop the proposed rate design, and is alluded to on pages 16-17 of the joint testimony of Simek and Therrien. They describe a two-step process: the proposed customer charges were developed first, and the remainder of the revenue requirement was recovered through the volumetric rates. The Company's marginal cost estimates were used in both steps.

> To determine the appropriate level of customer charges for each class, we considered: (1) the marginal customer costs resulting from the marginal cost study; (2) rate continuity; and (3) customer impacts.[15]

The second and third items just mentioned did not support increasing the customer charges; rather, they ameliorated the extremely large increases that would be needed to move these rates all the way to the Company's estimate of marginal cost. For example, the Company is proposing to increase the customer charge for the residential R-1 (non-heating) class by $6.23, or 40.8%, from the current tariff level of $15.27 to the proposed level of $21.50. The marginal cost calculated by the Company for this class is $61.17. They would have needed to increase this rate element by 300% – from $15.27 to $61.17 – in order to go all the way to the cost they calculated. Needless to say, such an extreme increase in this rate element would not be consistent with the principle of rate continuity, and the resulting customer impacts would also be of potential concern – hence the reference to the second and third factors they considered in deciding on the proposed customer charges.

Q. What has the Company proposed for other customer classes?

A. For the other residential tariffs it used a similar approach, increasing the customer charge to a level that moves closer to the numbers calculated in its marginal cost study, then adjusting the remaining (volumetric) rate elements as necessary to achieve the requested

15 Direct testimony of Simek and Therrien, Page 17.

revenue requirement. The primary thrust of this exercise was to move customer charges closer to the cost level calculated by the Company. However, it ameliorated that movement in the interest of maintaining a degree of rate continuity and to avoid excessive customer bill impacts.

Since the proposed rate design is closely tied to the Company's marginal cost results, I will discuss the appropriate relationship between costs and prices in the next major section, followed by my discussion of the Company's marginal cost study. I would note, however, that EnergyNorth's primary focus seems to be on increasing the customer charges; the cost study is in more of a supporting role. One reason I say that is because the Company is proposing increases to its customer charges even for tariffs where moving in that direction isn't supported by its cost study. This is apparent from this passage in its testimony:

> Although Attachment RATES-5 Line 99 also indicates that the proposed C&I rate class customer charges exceed the marginal unit customer costs for rates G-42, G-43, G-52, and G-53, the customer charges for these rate classes were increased by 10 percent,

The Company could have proposed maintaining the existing customer charges, or begun to move them toward the (lower) calculated marginal cost level. The Company instead proposed to increase the customer charges by 10% – which is about five times the recent annual rate of inflation. No cost justification was offered to support this proposal, nor was there any acknowledgement that this would exacerbate and perpetuate an existing pattern of overcharging low use customers (according to its own cost calculations). The stated reason supporting this proposal is that the 10% increase was necessary to ensure a large enough share of the rate increase would be paid by low usage customers relative to larger customers in the same class:

> if we had not increased these rate class customer charges, large gas users in each of these classes would experience disproportionately large increases, relative to smaller gas users in each of these rate classes.

While applying a similar percentage increase to both small and large customers may seem reasonable, what is notable is that this reasoning was <u>not</u> followed in the opposite direction. Nor was it followed with respect to the prices charged to customers in the Keene division.

If it had consistently applied this line of reasoning, the Company could have concluded that large users in the Keene division should pay 10% higher rates, rather than decreased, to ensure that other customers do not experience disproportionately large increases. Similarly, if it had following this reasoning consistently, it would have concluded that residential customer charges should not be drastically increased, because a disproportional increase to this rate element has the effect of requiring small residential gas users to experience disproportionately large increases, relative to larger gas users in the same rate class. In other words, the emphasis on maintaining existing rate relationships seems to be somewhat selective in EnergyNorth's proposals. The one thing that seems to consistently run throughout the Company's rate proposals (as well as its decoupling proposal) is a desire for greater revenue stability, which would be achieved by imposing higher customer charges.

Q. Do you agree with this emphasis on increasing customer charges?

A. No. The public interest can best be advanced by moving in the opposite direction. A gradual process may be more appropriate than immediately implementing the reductions in customer charges that could be justified based on the evidence in this case, but it would be appropriate to at least begin to move that direction. By decreasing the fixed part of the bill and increasing the volumetric part (increasing the per-therm rate – particularly in the tail block), the Commission can provide a stronger incentive for customers to fully participate in controlling their utility bill, and a stronger incentive to learn about and adopt more energy efficient products and technologies. By moving in the opposite direction to that proposed by EnergyNorth, the Commission can reduce the burden on small customers, thereby making the tariff structure more equitable, it can enable customers to gain greater control over their monthly utility bill, and it can advance the broad public interest by encouraging energy efficiency.

EnergyNorth's current rate structure does not provide a very strong incentive for customers to increase the insulation in their home or business, or to replace existing, inefficient water heaters and furnaces with more energy efficient ones. Reasonable steps can and should be taken in this proceeding to strengthen these incentives by increasing the volumetric rates, and especially the tail block rates. These steps will also have the salutary effect of reducing the burden on low energy users and providing all customers with an increased opportunity to gain control over their utility bill.

B. Comparison to Other Utilities' Rates

Q. How do the Company's existing and proposed customer charges compare to those in other jurisdictions?

A. With the exception of the rates paid by customers in the Keene division, EnergyNorth's customer charges are already higher than those charged by many other utilities in New England and elsewhere around the country. In May 2015, the American Gas Association published a report that concluded that the nationwide median residential customer charge was just $11.25 per month, while the customer charge in EnergyNorth's R-1 (residential non-heating) tariff is currently $15.27. It's R-3 (residential heating) tariff includes a customer charge of $22.10, which is nearly double the nationwide median reported by the American Gas Association. A substantial discrepancy also exists in the Company's other tariffs. For instance, the nationwide median rate for commercial customers was reported to be $22 per month, which is less than half the Company's current customer charge of $48.36 for G-41 and G51 (commercial/industrial – low annual use) customers. The discrepancy is even more extreme for the Company's G-42 (commercial/industrial – medium annual use) customers, who are currently paying a fixed monthly rate of $145.08 in addition to the volumetric rate.

Table 2

2015 Natural Gas Utility Median Monthly Customer Charges by Census Region

Census Region	Residential	Commercial
New England	$ 13.50	$ 28.41
Middle Atlantic	$ 14.60	$ 23.60
East North Central	$ 11.38	$ 24.00
West North Central	$ 13.16	$ 24.40
South Atlantic	$ 10.00	$ 22.00
East South Central	$ 14.00	$ 16.96
West South Central	$ 13.24	$ 18.51
Mountain	$ 10.80	$ 20.00
Pacific	$ 4.95	$ 14.90

As shown in the table above, the data in the American Gas Association report suggest that EnergyNorth's New Hampshire customers may already be paying some of the highest customer charges in the United Sates. Further increasing these charges may seem appealing to the Company, since this would further increase the stability of its revenues. However, the current high customer charges already impose a large burden on low usage customers compared to the rates charged by many other utilities. Furthermore, the higher the customer charge, the lower the volumetric rate. Tilting the balance away from volumetric rates detracts from the widely accepted public policy goal of encouraging energy conservation.

C. Fixed Cost Recovery

Q. Gas utilities sometimes argue that a fixed monthly fee is the correct way to recover costs that are fixed. How do you respond to this argument?

A. I am willing to concede there is some intuitive appeal to this argument. However, it is at most a pricing tactic rather than a valid goal – the actual goal is revenue predictability or stability. This goal makes sense from a utility's perspective, but it is not a high priority from a public interest perspective. Nor is there any policy reason why fixed costs need to be recovered through fixed rates. A stable, more predictable revenue stream makes it easier to manage a firm's cash flows, and it could might reduce the risks borne by the firm's stockholders to a small degree, but neither of these concerns merit much weight from a public policy perspective.

In fact, this pricing tactic does not advance the public interest, since it conflicts other, more significant policy goals, like inter-customer equity and encouraging energy conservation. Moreover, recovering fixed costs as a uniform amount per customer is not consistent with the fixed cost recovery mechanism that is typical of most unregulated markets. In competitive markets the interaction of supply and demand determines prices, and there is no consistent tendency for fixed costs to be recovered through “fixed charges” nor is there any tendency to charge every customer the same amount each month, regardless of how much or how little they use.

Where substantial fixed, sunk and joint costs exist, the portion of these costs that is recovered from different products or services will not be a uniform amount each month, but instead will vary depending upon supply and demand conditions. More specifically, the relative cost-recovery shares will depend on the degree to which different types of purchasers benefit from the production process, and the relative strength of demand for the different products that are being jointly produced. Each customer will not contribute a uniform, fixed dollar amount toward the recovery of joint and common costs merely because those costs are fixed. To the contrary, cost recovery will vary widely, with larger customers tending to contribute more than smaller customers (because they use more, and benefit more from the common production process). Similarly, if some of the products offered by the firm are perceived to be more valuable than others, those will tend to have a larger markup, resulting in a larger contribution toward joint and common costs than is obtained from those products that are perceived to be less valuable.

In most parts of the economy, the amount contributed by specific customers, or specific products will vary depending on the strength of demand. The stronger the demand – and in that sense, the greater the benefit received from joint and common production processes – the greater the share of joint and common costs that will be borne by any particular product, service, customer, or customer group.

Q. EnergyNorth's rates are determined by the Commission, not by market forces. Should the Commission deviate from the normal market outcome to require uniform per-customer contributions toward fixed costs?

A. No. Just because the Commission has the option of doing this doesn't make it preferable. In fact, the advantages of non-uniform cost recovery can be demonstrated by looking at a different analogy: how taxing authorities most frequently handle the problem of spreading the tax burden (recovering the fixed costs of providing government services).

Consider a hypothetical small business owner who operates a 1,000 square foot retail store. This retailer competes with several other retailers located on the same side of the street, which are twice as large, as well as a 50,000 square foot department store located across the street. Under the cost recovery approach advocated by the Company, the department store would contribute the same amount toward the local municipality's fixed costs as the smallest competitor on the street, despite being 50 times larger.

It is certainly true that many of the costs of providing government services (like the cost of maintaining a traffic light at the end of the street where all of the stores are located) are fixed, at least in the sense they do not directly vary with the size of each store. Nevertheless, few people would argue it would be more equitable to require the smallest store on the block to pay the same dollar amount per month toward the municipality's fixed costs as the largest store on the block, merely because the costs are the same every month, and cannot be directly attributed to any one store. The inequitable nature of a uniform, "everyone pays the same amount" approach to cost recovery becomes even clearer when their respective shares of the fixed costs are compared on an apples-to-apples basis. The department store would end up paying 98% less per square foot for the municipality's fixed costs than the smallest store. Similarly, other stores on the the street would pay half as much per square foot as the smallest store. Most people will readily concur that this would not be a fair approach to cost recovery.

Q. Does similar reasoning apply to the recovery of fixed costs from different size residences?

A. Yes. If the fixed costs of government were going to be collected as a uniform dollar amount from all residences, both small and large, a hypothetical 400 square foot studio apartment would pay as much as a luxurious 3,500 square foot house – even though many of the municipal services (like maintaining 24-hour per day police and fire protection) provide greater benefits to the owner of the larger, more costly residence. In practice, by collecting property taxes in proportion to assessed value, an attempt is made to ensure that all types and sizes of residences make a reasonable contribution toward the fixed costs of providing government services – and that contribution is not a uniform monthly dollar amount. Instead, the amount contributed through taxes varies widely, with large residences generally contributing more than small residences.

Q. What conclusion do you draw from this analogy?

A. First, this analogy demonstrates that the rate design I am recommending is consistent with the cost recovery pattern that is most frequently observed when government policy makers, tasked with serving the public interest, decide how best to recover the fixed costs of government.

Second, this analogy helps demonstrate the inherent fairness of a non-uniform cost recovery pattern. Taxes provide an example where non-uniform cost recovery is familiar and a pattern that most of us readily accept without dispute. In fact, it is hard to imagine anyone arguing that the smallest store on the block (or its landlord) should pay the exact same dollar amount in property taxes as the largest store. Over the course of many years, involving many different public policy decision-makers in many different jurisdictions, it has been the common practice to spread the tax burden widely but not uniformly. Virtually all local, state and federal taxes are recovered from households and businesses in ways that ensure that small taxpayers pay much less than large ones. The largest taxpayers, who are in the strongest position to pay for government services, pay the lion's share of the tax burden. This pattern of cost recovery is widely accepted because it spreads the cost of government more equitably than a system that requires every taxpayer to pay the same dollar amount. In the next section I will demonstrate that non-uniform fixed cost recovery is also prevalent in most unregulated markets.

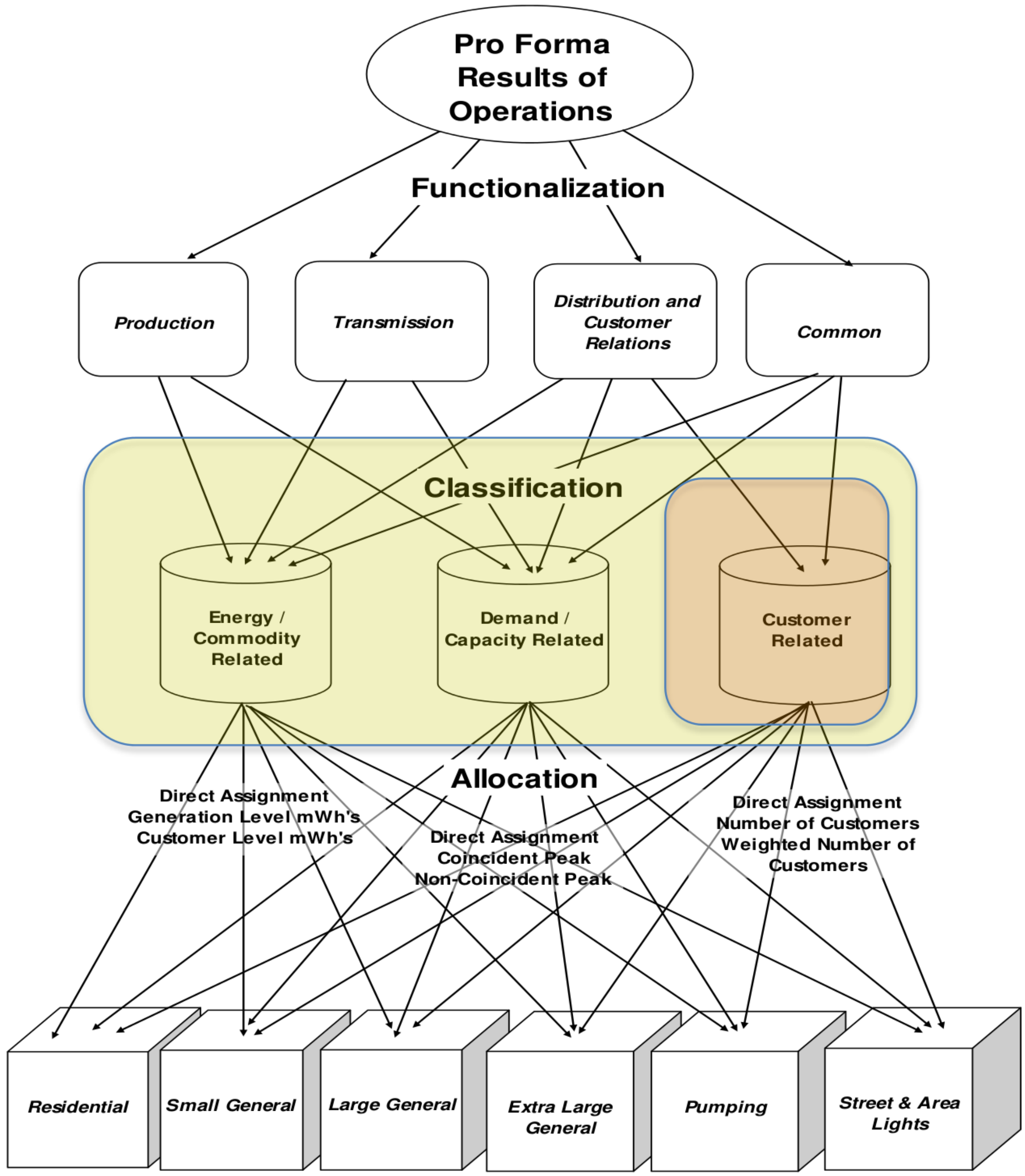
III. ECONOMIC COSTS AND OPTIMAL PRICES

Q. Is an understanding of economic cost concepts helpful in resolving the rate design and revenue allocation issues in this proceeding?

A. Yes. The Company developed an economic cost study, which it characterizes as a "marginal cost" study. It heavily relied on the results of these calculations in developing its proposed revenue allocation (distributing the revenue requirements to different customer classes), and its rate design proposals. In fact, its marginal cost study is the primary – virtually the only – support provided by EnergyNorth for its proposed changes to its existing rate design. While the Company also provided a functional (embedded) cost study, it is only of peripheral importance – helping determine what portion of the Company's revenue requirement will be recovered through base rates and what portion will be recovered through the cost of gas mechanism.

The mechanics of a traditional embedded cost allocation process are well-established and not controversial, although judgments that are made during that process can be very controversial. The mechanics of this process are nicely illustrated in the following flow chart, which was developed by the Regulatory Assistance Project and provided on page 11 of its slide presentation, Smart Rate Design for a Smart Future, dated August 4, 2015.

ELECTRIC COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group

In the first major step, called "functionalization," historical accounting costs are organized into various operating functions (e.g., production, transmission, distribution, customer accounting and customer service). The Company used this process to determine what portion of the overall revenue requirement will be recovered through the Cost of Gas mechanism, and what portion will be recovered through base distribution rates.

In jurisdictions where an embedded cost study is used for rate design purposes, two additional steps are needed. In the second major step – called "classification" – costs are grouped into three rate-related classifications: demand-related, commodity-related, and customer-related. In the third major step, these costs are allocated to specific customer classes. The allocated cost results are also sometimes used to support proposals for specific rate elements – for instance, determining what portion of the cost should be recovered through demand charges, and what portion through customer charges.

The initial steps taken by the Company in developing its marginal cost study were similar to the functionalization and classification steps just described. However, unlike a typical embedded cost study, judgments were not applied in allocating costs to various customer classes. Instead, a similar result was achieved by applying judgments concerning the way various costs were estimated, and the degree to which particular costs were assumed to vary "at the margin." These judgments, occurring within the work papers for the marginal cost study and not discussed in detail in the Company's direct testimony, largely determined the magnitude of the marginal costs that were estimated. In turn, these estimates provided most of the support for EnergyNorth's proposals with respect to the degree to which rates for specific customer classes should be increased (revenue allocation), and the degree to which specific rate elements should be increased or decreased for each class (rate design).

I will discuss some of these judgments in detail later in my testimony. For the moment it is sufficient to note that these judgments were crucial to the final conclusions reached in the study – including the conclusions that were reached concerning the alleged level of fixed "customer costs" (which support EnergyNorth's proposals to increase its customer charges) and the level of "demand costs" (which support its proposals for volumetric rates). The methodology and assumptions used in analyzing "customer costs" and "demand costs" were not consistent. These inconsistencies helped create the pattern of costs which the Company cites as support for its rate design and revenue allocation proposals.

Q. The Company provided both a marginal cost study and an embedded cost study. Can you please explain the difference between these two different types of cost?

A. There are at least three important differences.

First, and most fundamentally, embedded costs are derived entirely from the accounting records of the firm, and are heavily influenced by and dependent upon the conventions adopted by the firm in books and records. In contrast, marginal costs are a particular type of economic cost. Economic costs can be estimated using data from a wide variety of different sources including accounting records, engineering cost estimates, and special studies.

Second, a typical embedded cost study is focused on allocating total costs, whereas a marginal cost study does not (or should not) focus on total cost, or cost allocations. Instead, the focus should be on the extent to which costs vary "at the margin."

Third, because the term "marginal cost" is taken from the economic literature, the usefulness and validity of the Company's marginal cost estimates and its underlying assumptions, should be judged in that context. One way to test the validity of a marginal cost study is to examine how well it matches up with the way economists define and analyze costs. Does the study adequately consider opportunity costs? Is the study focused on a logical, internally consistent "run" or planning horizon? Is the selected planning horizon appropriate given the purpose for which costs are being studied? As I will explain later in my testimony, the Company's marginal cost study fails all of these tests. To understand why it falls short, it will be necessary to explain various concepts from economics.

A. Marginal, Variable, Fixed, and Total Costs

Q. Are there certain economic cost concepts that are important to understanding your analysis of the Company's marginal cost study and pricing proposals in this proceeding?

A. Yes. In economics, the most fundamental and important types of costs are fixed cost, variable cost, total cost, average cost, marginal cost, incremental cost, and stand-alone cost. All of these are integral parts of economic theory – along with other, more specialized cost concepts, including sunk, direct, joint, and common costs. All of these cost concepts are significant to the issues in this proceeding.

Fixed costs do not change with the level of production, during the planning period or "run" under consideration. **Variable costs** change directly (but not necessarily

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proportionately) with the level of production. It should be noted that the exact same item might be a fixed in the short-run and a variable in the long-run. Together, fixed and variable costs constitute **total cost**, which is the sum of all costs incurred by the firm to produce a given level of output. Dividing the total cost of producing a given volume of output by the total number of units produced, one can calculate **average total cost**.

Short-run costs are those which arise in situations where most costs are fixed. In contrast, **long-run costs** are those calculated under the assumption that many, if not all, costs are variable, and relatively few costs are fixed or sunk. The classic long-run concept is sometimes known as a "scorched earth" approach – that is, no pre-existing plant is considered in the analysis. Instead, the firm is free to build precisely the size and type of plant which best fits the assumed output level. However, even in the long-run some aspects of the production process are typically assumed to remain inflexible – like the technology the firm uses, or the state or region where the firm operates.

Incremental cost is the change in total cost resulting from a specified increase or decrease in output. In mathematical terms, incremental cost equals total cost assuming a specific increment of output is produced, minus total cost assuming the increment is not produced. Incremental cost is often stated on a per-unit basis, with the change in cost divided by the change in output. Incremental cost can vary widely, depending upon the increment of output under consideration. If the entire increment from zero units to the total volume of output is considered, incremental cost is identical to total cost. Similarly, where the increment ranges from zero to total output, incremental cost per unit is identical to average cost per unit for that volume of output. Because a wide variety of different increments can be specified, a wide variety of different incremental costs can be

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calculated. Thus, in considering any estimate of incremental cost it is crucially important to determine whether or not the specified increment is relevant to the issues at hand.

Marginal cost is the same as incremental cost where the increment is extremely small (e.g., one unit) and the cost function is smooth and continuous. In mathematical terms, marginal cost is the first derivative of the total cost function with respect to output (the rate of change in total cost as output changes).

A wide array of different incremental costs can potentially be defined, corresponding to an array of different increments that can potentially be analyzed. Marginal cost corresponds to one very specific part of this overall array – where the increment is narrowly defined and extremely small. One important distinction between marginal and incremental cost is worth noting here: when large increments are studied, the cost of adding an additional increment of output will often be quite different from the cost of reducing output by an increment of the same magnitude. In contrast, if the cost function is smooth and continuous, marginal cost will generally be the same regardless of whether it is measured by how much total cost increases when the volume of production increases by an extremely small amount, or how much total cost decreases when the volume of production decreases by an extremely small amount.

In the economic literature, a crucial distinction is drawn between marginal costs and average costs. That distinction is closely related to (but subtly different from) the distinction between fixed and variable costs. In essence, average total cost per unit spreads both fixed and variable costs over the total volume of production, while marginal cost does not include fixed costs. However, the discussion can become complicated, because the extent to which particular costs vary “at the margin” can change depending upon the circumstances, including the specific "planning horizon" or "run" that is being studied. The distinction between average cost and marginal cost is of crucial importance to the highly refined understanding of costs that has been developed by economists, which has laid the foundation for much of the progress that has been made in microeconomic theory and empirical research over the past 125 years.

The fundamental reason why I so strongly disagree with the Company's marginal cost estimates is that it has not made appropriate, internally consistent distinctions between which costs are fixed or "sunk" and which costs are variable, and because it has not selected and applied an appropriate, internally consistent planning horizon or "run" that is appropriate to this context. I will explain both of these problems in further detail, after providing the necessary foundation for this explanation.

Q. Can you elaborate on the distinction between fixed and variable costs, and explain how this distinction relates to incremental or marginal cost?

A. Yes. As the name implies, a fixed cost does not increase or decrease as the volume of production changes. In contrast, a variable cost is one that changes in response to changes in production volume. Fixed and sunk costs have no impact on marginal cost. In fact, determining which costs are fixed and which ones are variable is crucial to whatever conclusions one reaches concerning the level of marginal costs in any particular context. It must be kept in mind, however, that the exact same item may be variable in the long-run and fixed in the short-run. Hence, the selected planning horizon – and the extent to which specific costs are assumed to vary in that planning horizon – largely determines the results of a valid marginal cost analysis.

Fixed costs are those elements of the firm's total cost which do not increase (in the context of the specified planning horizon) as the volume of output increases. **Sunk costs** are similar, except that fixed costs can be eliminated if the firm is willing to exit the market entirely (e.g., by abandoning its equipment or converting it to another purpose), while sunk costs cannot be eliminated in this manner. Aside from this difference, sunk costs can be thought of as an extreme case or a special type of fixed cost. Because sunk costs cannot be avoided or changed under any circumstances, they are irrelevant (once incurred) for most economic decisions. In contrast, although fixed costs do not affect marginal costs, they are not entirely irrelevant, because they can be avoided if the firm is willing to exit the market.

A typical example of a fixed cost is the cost of owning a factory building; as long as the building is in use as a factory, its costs are unavoidable and they do not vary with the volume of output produced by the factory. However, the firm can avoid the costs of ownership if it discontinues production and sells the building to someone who will convert it to another use (e.g. condominiums or a factory producing a different product). Hence, the cost of the building would be classified as fixed, not sunk, to the extent the building can be converted to a different purpose.[16] If the building has been optimized for a specific production process, it will likely involve a combination of fixed and sunk costs. To the extent a willing buyer would not pay extra for these unique attributes, and instead

16 A mere change in legal ownership is not sufficient; the potential to convert to a different use helps determine whether a cost is fixed or sunk.

would simply demolish them or ignore them, the cost of those unique attributes would be sunk.

Q. Can you clarify the distinction between fixed and sunk costs?

A. Yes. A few examples will suffice. A natural gas utility incurs some capital-related costs, like property insurance and property taxes, that economists classify as fixed costs, because they do not vary with day to day or month to month fluctuations in the volume of production. That is not to say they cannot be changed under any circumstances. Fixed costs can typically be reduced or eliminated by divesting, shutting down, or abandoning some of the firm's capital investment. In the case of a gas utility, it could potentially reduce its property insurance by disposing of some of its equipment, or it might be able to reduce its property taxes by permanently shutting down parts of its system. Since a gas distribution system cannot be moved to a new location, economists classify the capital invested in the system itself as a sunk cost (rather than a fixed one), except to the extent portions of that capital investment can be recouped by selling parts of the system to another firm that converts it to a different purpose. For instance, if a telecommunications carrier would be willing to purchase parts of the distribution system in order to convert some of the pipes into conduit for fiber optic cables, the price the carrier would be willing to pay for the pipes would be classified as a fixed cost of the gas utility; the remainder of the investment would be classified as sunk.

A classic example of a sunk cost is the cost of writing a novel. Once this cost is incurred, it cannot be avoided, reduced or eliminated, regardless of whether or not the novel is published or how many copies are sold. Stated another way, sunk costs are irretrievable once they are incurred. From that point forward, they are completely irrelevant to any pricing, production, or other economic decisions that must be made.

B. Long-run versus Short-run

Q. Can you elaborate on the distinction between long-run and short-run economic costs?

A. Yes. The degree to which costs are variable depends on the "run," which is a technical term that is closely tied to the concept of a "planning horizon." In the short-run, the firm minimizes its costs by focusing on options, like hiring or firing employees or adding overtime, which can be analyzed and implemented quickly. Notably, the firm's existing capital investment is considered to be a fixed or sunk cost in the short-run. Additional, more fundamental, changes in the firm's operations become feasible over longer periods of time. These options include investing in additional plant and equipment, replacing some of its existing equipment with a different type of equipment, or selling some of its capital equipment and scaling back the scale of its operations. By definition, none of these options are available to the firm's managers in the short-run, because of the durability of its existing capital investment, and the difficulties involved with making changes to that investment.

While it is simpler to discuss these concepts by contrasting just two "runs" – the "short-run" and the "long-run" – it is more accurate and realistic to think in terms of an entire continuum of possibilities, or "runs." The longer the "run", the greater the extent to which the capital-related factors of production can be varied and optimized. Stated another way, as the planning horizon becomes longer, the firm is not as limited by, or significantly constrained by, inherent limitations and characteristics of its existing capital investment.

Similarly, while it is easier to simplify the discussion by equating the “run” with different periods of time, it's important to recognize that the extent to which capital-related factors of production can be varied, (and how long it typically takes for a firm to replace its existing capital stock), can vary greatly across different industries. The time period corresponding to the “short run” in one industry might correspond to the “long-run” in a different industry. While the “run” is related to time, the amount of time is not as important as the degree to which the factors of production can be optimized.

In general, as the “run” becomes longer, it becomes feasible to analyze and optimize more and more aspects of the firm's production process, including more and more aspects of the firm's capital investment. Economists often explain the concept of the “run” with reference to time, because this makes it easier to understand how additional options open up for the firm as it moves along the continuum from the short-run to the long-run. For example, as the amount of available time for making decisions and implementing them increases, the firm will need to decide how, and whether, to replace equipment that is wearing out. Similarly, with more time the firm may be able to find someone willing to purchase some of its existing equipment and move it to a new location, to be used in a different production process.

By thinking in terms of how the firm can respond differently over different time periods it is easy to grasp the key attributes of the economic concept of the “run”. For instance, it is easy to see why the cost of a machine with a useful economic life of five years will be classified as fixed in a six month planning horizon, but the cost of that same machine will be reclassified as variable over a ten year planning horizon. Hence, there is no universally "correct" way of classifying any particular item. That does not mean that "anything goes." There are clearly "wrong" ways of classifying specific costs in any given planning horizon. It is self-evident that if the planning horizon is long enough to allow the firm to replace an existing machine with a different size or type of machine, then the electricity used to operate the machine should also be classified as a variable cost. Similarly, if a cost is classified as variable in the short run, it has to be classified as variable in the long run, as well. One cannot arbitrarily pick and choose which items will be categorized as variable or fixed – logical consistency is mandatory.

Q. Can you provide an example which clearly illustrates the concept of the "run"?

A. Yes. A classic example used by economists is the costs incurred by a fisherman. To make this example easy to relate to, it is usually introduced and explained in terms of time – noting that all costs may be fixed over a short period of time, but many of these cost become variable over a longer period of time. However, to fully appreciate the nuances of this example, it is helpful to keep in mind that in economic theory, the "run" does not actually refer to any specific period of time. Rather, the "run" refers to the degree to which costs (particularly capital investments) are assumed to be variable, rather than fixed or sunk – and in our common experience this variability is correlated with time.

Q. Can you use this illustration to clarify how the "run" relates to time, at the short end of the spectrum?

A. Yes. Economic theory envisions a continuum of different planning horizons. The extreme short end of the continuum is sometimes referred to as the "market period." This corresponds to the situation confronting a fisherman during the brief period after unloading the fish but prior to selling them. The load of fish cannot be "uncaught" and the costs of catching the fish cannot be reduced by reducing the size of the catch. Nor can costs be reduced by selling some of the fish and throwing the rest away. The costs of catching the fish are sunk, and cannot be avoided or varied at that point.

However, an entire array of "runs" exists. Consider a slightly different example, which can also be classified as an example of the "extreme short-run" – the situation confronting the fisherman during short period after the fish are caught until they are sold. The cost of fuel that was burned while locating and catching the fish is a sunk, but the cost of the additional fuel needed to haul the heavy catch all the way back to shore can potentially be avoided by dumping the fish overboard. The small amount of labor that could be avoided by dumping the catch overboard and coming more quickly back to shore can also be avoided (in theory). Accordingly, over this slightly longer time period, the marginal cost per pound of fish would be slightly higher than the even more abbreviated "market period". Needless to say, in both of these examples, the total costs incurred by the fisherman are far above zero, and the captain's goal is to recoup all of the costs, including the sunk costs.

Q. Can you extend this example to illustrate the "short-run"?

A. Yes. The classic short-run is a planning horizon where the fisherman has many more options than in the market period or the extreme short-run, but all of the fisherman's capital costs remain fixed. It is easy to envision some of these options if you visualize what the fisherman can do over the course of a week or two. For example, the cost of fuel and labor can be varied, as the fisherman decides how much time to spend on the water each day, or how many days per week she will go fishing. By spending more time on the water, the fisherman can catch more fish, at the cost of burning more fuel. Looking at the same option from the other direction, the amount of fuel burned can be limited on a daily or weekly basis, but this reduction in fuel costs will typically result in fewer fish being caught.

If the captain chooses to use more fuel and spend more time on the water, the marginal cost per pound of fish acquired will begin to increase, once a point of diminishing returns is reached, because she will be forced to spend more and more time on the water, searching farther and farther afield from the prime locations where a lot of fish can almost always be found. This extra time on the water will help the fisherman bring back a larger catch, but there will be higher variable costs, because of the extra fuel that will be burned. If this strategy is pursued too far, the boat could become overloaded, and the captain will be forced to slow down when returning to shore, in order to avoid capsizing the boat. All of these factors tend to drive up the marginal cost of each pound of fish brought to shore, once the point of diminishing returns is reached.

Similarly, in the short-run the fisherman can hire additional workers to go out on the boat. These workers help haul in the nets more quickly, increasing the size of the catch for any given expenditure on fuel. However, this strategy will increase short-run marginal cost, since the extra workers will need to be paid for the entire time they are on the water – not just when they are actually needed to help with bringing up the nets.

Q. Can you extend this example to illustrate the "long-run"?

A. Yes. The long-run corresponds to a planning horizon where most capital-related costs become variable – the fisherman is assumed to have many capital-related options. While the long-run is not tied to any specific period of time, in the fishing context it can be thought of as a time period that is long enough to provide an opportunity to investigate and evaluate capital-related options, like replacing the existing boat. For example, the fisherman might evaluate the option of selling the existing boat and buying a faster one with more powerful engines. This would make it feasible to the prime fishing spots more quickly, saving time, and provide the option of going to additional locations on days when the catch is poor at the first location. Or, the fisherman could invest in a larger boat, which would allow the captain to haul more fish back to shore (at least on days when enough fish can be found to fill the larger boat).

The fisherman could also evaluate less drastic capital-related options, like installing better, more powerful gear for hauling in the nets. This might reduce labor costs without requiring a change in boats. Similarly, the fisherman might invest in technology which helps quickly and precisely find the fish, so less time will be wasted letting down the nets and hauling them back up with a disappointing catch. In the long-run, there will be options for reducing the capital investment – not just increasing it. For instance, a smaller, cheaper boat might be chosen, which costs less to own and operate, but doesn't hold as many fish. In the long-run, this might allow the fisherman to increase profits by more closely conforming the boat to the size of the catch that can easily be found and hauled back on a typical day. With a smaller boat, the fisherman might be able to focus exclusively on prime fishing locations, without wasting so much time going to other, less reliable, or less plentiful locations in an effort to fill the existing boat.

As this example demonstrates, while the difference between the short-run and the long-run can easily be envisioned and discussed in terms of time periods of different durations, the really crucial difference is the degree to which capital costs are variable. In the short-run, the fisherman is stuck with the existing boat, which represents a fixed cost that cannot be easily avoided or varied. In the short-run, the fisherman cannot change the capacity, technology, configuration and other attributes of the existing capital equipment. Hence, all of the costs of owning the boat, including the cost of capital, insurance, and property taxes are fixed (they cannot be varied) in the short-run. In turn, it is easy to see why marginal costs would not necessarily be the same in the short-run and the long-run. Since marginal cost is the rate of change in total cost resulting from an extremely small change in output, differences in the degree to which various costs can be varied will result in differences between short-run marginal cost and long-run marginal cost.

Q. Can you clarify some key differences between the long-run and the short-run in the specific context of EnergyNorth?

A. Yes. Compared to the fishing example, a gas distribution system has high capital-related costs relative to size of the other, more easily varied, costs. Hence, EnergyNorth's marginal costs are necessarily going to be far below its average total cost in the short-run. This follows directly from the fact that in actual practice, the Company's costs are mostly fixed or sunk, and ample capacity undoubtedly exists along many of the routes where it has installed distribution mains. As a result, most customers can be delivered as much gas as they want, whenever they want it, without incurring "opportunity costs" or the need to curtail the delivery of gas to other customers.

This is in contrast to the fishing example, where every pound of fish that is caught increases the amount of fuel that is burned, and where time and space constraints create trade-offs or "opportunity costs" that increase short-run marginal costs. The amount of one type of fish that can be brought back to shore during any given fishing trip will be limited by the amount of other types of fish that are also brought back on the same trip. In effect, increasing the volume produced of one product (the harvesting of a particular type of fish) will make it more difficult or costly to produce any other products (the harvesting of other types of fish). Space is limited on a boat, and the time spent hauling in one type of fish will reduce the time available for hauling in a different type of fish – all of which translates into higher short-run marginal costs for any given type of fish.

To some degree, something analogous can apply to parts of EnergyNorth's gas delivery system. If capacity constraints or potential low pressure conditions exist on parts of the system, these problems will translate into higher short-run marginal costs. Low pressure problems can result in opportunity costs because increased deliveries to one set of customers can only be accomplished safely by reducing deliveries to another set of customers, which will increase short-run marginal costs.

As a general matter, however, we can anticipate that the short-run marginal cost of delivering gas to most customers will be very low (approaching zero) during most of the year. Because short-run marginal costs are so low, it is readily apparent that gas delivery prices that are set equal to short-run marginal cost will not allow EnergyNorth to recover its revenue requirement. A substantial contribution above short-run marginal cost is necessary for the firm to remain viable and ensure recovery of its total costs over the long-run.

Because many capital investments can be varied in the long-run, the long-run marginal cost of distributing gas will likely be much higher. Consider, for example, a long-run planning horizon that corresponds to the degree to which capital investments can potentially be varied over a typical 10 to 20 year planning horizon. Unlike in the short-run, in this longer planning horizon, the cost of EnergyNorth's distribution mains is not entirely fixed or sunk, and will instead (to some degree) be variable. For instance, over this time period new mains may need to be installed along some routes, because the existing mains are nearing the end of their useful life, or becoming unacceptably leak-prone. Over a 10 to 20 year time period, some degree of congestion will likely arise, with growth in usage in some areas creating opportunity costs (a reduction in usage by one group of customers might be necessary to accommodate increased deliveries to another group of customers) or the need for investments in main reinforcements or expansion.

Q. Can you explain in more depth why the long-run marginal cost of delivering gas tends to be higher than the short-run marginal cost?

A. Yes. There are several factors that determine the extent to which marginal costs will differ between the short-run and the long-run. These factors will differ depending on the technical characteristics of the production function, but in the specific case of a natural gas utility, the overall tendency will be for long-run marginal costs to be higher than short-run marginal costs. The additional flexibility that is available in a long-run planning horizon will provide opportunities to reduce total costs that don't exist in the short-run, and in some situations this can translate into lower marginal costs in the long-run than in the short-run. However, costs that were classified as fixed or sunk in the short-run may be reclassified as variable as the planning horizon becomes longer, and this will tend to push long-run marginal costs above the level of short-run marginal cost (as fixed and sunk costs diminish in importance). Accordingly, we can confidently state that long-run marginal costs exceed short-run marginal costs for a typical gas distribution utility, since fixed and sunk costs are pervasive in the short-run, pushing short-run marginal costs down to very low levels.

While decisions concerning the replacement or retirement of certain mains, as well as the size of these mains can be optimized over the course of a longer planning horizon, these costs are not eliminated. To the contrary, due to the high cost of installing, reinforcing or replacing mains, the overall system-wide long-run marginal cost of mains will be far above the level observed in the short-run. In fact, due to inflation and other factors, the long-run marginal cost of mains could easily exceed the average embedded cost of the existing mains, despite the fact that the cost of mains in some parts of the system may still be classified as fixed or sunk.

Q. Are you suggesting that some fixed or sunk costs can still exist even in the long-run?

A. Yes. The distinction between treating capital-related costs as variable and treating them as fixed or sunk is fundamental to the concept of the planning horizon. In application, however, the theory is quite flexible, and can readily be adapted to different factual situations. There is nothing illegitimate or inappropriate about studying a planning horizon in which some of the firm's capital investment can be varied, while other aspects of its existing system are treated as fixed. Since the natural gas industry has extremely long-lived assets, this may be a much more relevant and realistic application of the "long-run" concept than a traditional "scorched earth" planning horizon, in which every aspect of the firm's capital investment is treated as variable.

Most of the pipes and other facilities owned by EnergyNorth have a useful economic life of 60 to 70 years or more. To entirely eliminate fixed and sunk costs it would be necessary to select a planning horizon or "run" that corresponds to an extremely long period of time – perhaps 100 years – but this would more typically be described as an "extreme long-run" planning horizon lieing at the extreme far end of the continuum of possibilities. In this extreme long-run, <u>all</u> costs would be assumed to be 100% variable, including those that can only be changed in a purely hypothetical scenario, or one that involves an extremely long period of time like 100 years.

In the fishing example, in contrast, the extreme long-run would not require such a long time period. Instead, it would involve a purely hypothetical analysis in which the firm is assumed to have not yet entered the business, and it is free to choose whether to operate out of Portsmouth, or to fish off the coast of Oregon or Alaska, or to invest in aquaculture to raise farm-bred fish, instead. Similarly, in the case of EnergyNorth, the equivalent extreme long-run planning horizon would involve a purely hypothetical scenario in which the firm has no sunk costs – it is considering the option of entering the market, and it has complete freedom to choose the locations where it will provide gas service, the routes where it will install distribution mains, and the specific buildings it will connect to its mains.

It is certainly possible to develop a cost study based upon "scorched earth" assumptions, in which the existing system is ignored. This would be a purely hypothetical system, which is optimized to fit current population and usage patterns. In that case, every main, every regulator, and every service line would be treated as 100% optional or variable. However, in my opinion, that analysis would not be particularly useful or relevant in this proceeding. The key questions in this proceeding can best be answered by taking a more realistic approach to analyzing economic costs. Many aspects of EnergyNorth's system should be taken as a given, and as a result some of its capital-related costs are more correctly classified as fixed or sunk.

Q. Can you clarify what you are recommending with regard to how long-run marginal costs should be defined in this proceeding?

A. Yes. The approach I am recommending can be thought of as the typical of a "long-run" which reflects the degree of flexibility that actually exists over a 10 to 20 year time period. This is similar to the time frame that is usually envisioned when discussing long-run costs in the context of a manufacturing firm. For instance, in the long-run it would typically be assumed that a manufacturer is not limited to the configuration and scale of its existing factories. The existing building can be abandoned or sold to someone who will use them for a different purpose; the firm can replace it with a different size factory, or one in a different location. However, it will likely have at least some aspects of its operations that remain fixed. For example, inventing and implementing an entirely new production process would not be an option – that sort of hypothetical possibility would be relegated to the "extreme long-run".

The approach I am recommending is more useful and appropriate than a purely short-run approach, or an extreme long-run approach. The distinction I am drawing is important because many of the facilities owned by EnergyNorth are installed in the ground and cannot be easily removed or downsized, yet they have a useful economic life of 60 years or more. During a 10 to 20 year time frame, only some of these facilities will need to be replaced or reinforced. Many parts of the system will remain unchanged no matter what decisions customers make in response to the prices that are established in this proceeding. It would be a mistake to ignore this reality and to arbitrarily treat sunk costs as if they were not sunk. It would be particularly inappropriate to treat sunk costs as if they were 100% variable, on an arbitrary, purely hypothetical basis. The truth is that many items in the system cannot be removed, replaced, or resized at will. While the latter view of cost variability is sometimes used in a "scored earth" planning horizon, it is not appropriate for use in this case.

That is not to say that purely short-run view of costs should be used. More useful and meaningful insights can be developed by thinking about the costing problem from the perspective of 10 to 20 year planning horizon, and recognizing that an array of different situations exist in different parts of EnergyNorth's New Hampshire service area. Along the existing route sending gas to any given customer, there is a certain probability that capacity constraints will result in significant opportunity costs over the next 10 to 20 years. Over a similar time scale, there is also a certain probability that usage growth, leak-prone pipes, or safety concerns will result in a need to reinforce, replace or enhance parts of the system (unless those parts are downsized or abandoned).

Consumption decisions by customers who are served by many parts of the system can potentially accelerate or delay the need for investments over the next 10 to 20 years, and their decisions can increase or decrease the magnitude of these investments. Similarly, customer decisions to increase or decrease gas consumption can potentially increase or reduce congestion on various parts of the system, which in turn will translate into opportunity costs that will increase the system-wide level of long-run marginal costs.

Appropriately developed, a system-wide measure of long-run marginal costs will consider the configuration and characteristics of the entire system, and potential future changes to that system, in conjunction with a distribution of probabilities. By considering this entire array of probabilities, circumstances where opportunity costs and capital replacement or expansion costs are high can be weighed with circumstances where marginal costs are low (for instance, where existing capacity can safely serve all relevant levels of demand over the next 50 or 60 years).

When viewed in this way, costs can analyzed on a precise, granular basis, reflecting the fact that the long-run marginal cost of distributing gas will be higher in locations where congestion or other problems will soon emerge, and lower in locations congestion is less of a concern, and capital-related costs are almost entirely sunk. This granular approach would be particularly useful if the analyst is considering the option of charging different prices in different geographically areas, or establishing a new sub-category of customers for pricing purposes. For instance, this sort of geographically granular cost data could be used to develop higher prices for customers in newly added residential neighborhoods or lower prices for commercial and industrial customers brought onto the system in an economic development zone where excess capacity exists.

The thrust of this discussion, however, is not to show how prices might be geographically de-averaged (which is not normally up for discussion). Instead, the point is that wide differences in circumstances at different locations in the system do not need to be ignored or simplified away; instead, these differences can be evaluated in terms of an overall system-wide distribution of probabilities. If customer's can sometimes reduce the total cost of the system by reducing their usage or leaving the system, and sometimes their decisions will have no impact due to pervasive sunk costs, both possibilities can be considered and weighed relative to the probability and relevance of each possibility. This is similar to the way automobile or fire insurance rates will often be based upon a detailed analysis of different circumstances. The actuaries recognize that risks vary depending on many different granular factors, but they ultimately roll up this information into broader prices which reflect an assessment of the overall pattern of probabilities and characteristics for an entire community, or a carefully defined category of customers.

C. Joint and Common Cost Recovery

Q. Earlier you mentioned joint and common costs. Can you please define these concepts, and explain how they relate to each other?

A. Yes.

Common costs are incurred when production processes yield two or more outputs. They are often common to the entire output of the firm but can be common to just some of the outputs produced by the firm. An increase in production of any one good will tend to increase the level of common costs; however, the increase will not necessarily be proportional. The costs of producing several products within a single firm may be less than the sum of the analogous costs that would be incurred if each of the products were produced separately (this is referred to as economies of scope).

Joint costs are a specific type of common cost—they are incurred when production processes yield two or more outputs in fixed proportions. A classic example arises in the joint production of leather and beef. Although cattle feed is a necessary input for the production of both gloves and hamburgers, there is no economically meaningful way to separate out the feed costs that are required to produce each. If the quantity of leather and beef is reduced, there will be a savings in the amount of cattle feeding costs, but it is impossible to say how much of this change in cost results from the change in the quantity of leather, and how much from the change in the quantity of beef.

Q. Are joint costs relevant to the issues in this proceeding?

A. Yes. Joint costs create a challenging puzzle for economic theory: it is not immediately obvious how joint costs are recovered in competitive markets, since they do not show up in the marginal costs which normally explain how prices are determined. The solution to this puzzle, which was discovered in the early 1900's, sheds light on some key aspects of EnergyNorth's pricing proposals in this case.

The solution to this puzzle is not only relevant to markets where joint costs are important (beef and hides) but also to markets where sunk costs are important (novels), for much the same reason (marginal costs may be close to zero). Understanding how prices are established when marginal costs are close to zero – or at least, too low to recover total costs – is useful in resolving some of the pricing issues in this case –

especially since many of the costs included in the Company's revenue requirement are to some degree sunk, or joint, or both.

Q. Before explaining how joint costs are recovered, can you explain how prices relate to marginal cost where the joint cost problem isn't present?

A. Decades before the joint cost puzzle was solved, economists had figured out that prices tend to equilibrate to a level that is equal to marginal cost. In fact, in situations where firms are accepting a market-determined prevailing price, marginal cost is the key to understanding how that prevaiing price is established. Among other insights gleaned from this analysis is that average cost is much less important than marginal cost.

A classic example is a wheat farmer. A wheat farmer has no control over the weather, and no control over the price of wheat, which is decided through nationwide forces of supply and demand. Hence, he concentrates on optimizing those aspects of his production function that he can control (deciding how many acres to plant, what crop rotation system to use, what seed to plant, how much fertilizer to use, how much to irrigate) in an attempt to maximize profits.

Like all competitive firms, wheat farmers make these types of decisions based on an analysis (whether explicit or implicit) that is tightly linked to marginal cost, rather than average cost. The firm increases each factor of production beyond the point of diminishing returns, until the point where the marginal revenue product associated with each input is equal to marginal resource cost of that input. While each firm makes these decisions independently, their individual decisions collectively lead to a convergence of industry-wide prices and marginal costs. In fact prices will exactly equal the industry-wide level of short-run marginal cost if the industry is in short-run equilibrium, and prices will equal long-run marginal cost if the industry is in long-run equilibrium. In equilibrium, every firm's marginal cost will exactly equal every other firm's marginal cost, despite wide differences in their individual circumstances, like the fertility of their soil, the types of equipment they use, and other details of their production function, and despite the lack of any coordination in their individual production decisions.

Because joint costs do not directly vary with the output of any one product, they are an exception to this general pattern, and it is not self-evident how they are recovered from customers. Among other insights that can be gleaned from solving the joint cost puzzle is that the general equilibrium conditions that were just described are not achieved exclusively by costs being adjusted to match prices. To some extent, the process also works in the reverse direction: prices also tend adjust to the level of marginal costs incurred by the typical firm. Decisions made by both producers and consumers are important in establishing prices in competitive markets. Succinctly stated, the interaction of both supply and demand determines what costs are incurred by producers and what prices are paid by consumers.

Q. Before explaining the joint costs in more detail, can you briefly summarize the solution?

A. Yes. Unregulated prices tend to reflect the direct costs incurred by producers – particularly marginal, or variable costs – plus a contribution toward otherwise unrecoverable indirect, joint and common costs that varies depending on market conditions and the strength of demand for different products or services. While market forces typically push prices toward short-run marginal cost, there are other market forces that push prices toward a long-run equilibrium level that exceeds this level, when this is necessary to ensure that each price includes an adequate contribution toward joint and common costs so that a typical firm can recover its total costs. In fact, demand conditions help determine the extent to which the firm's costs are recovered from specific products or services, and the extent to which its costs are recovered from specific customers or customer groups.

More specifically, if purely marginal cost-based prices would not be sufficient to ensure adequate total cost recovery, prices will instead equilibrate (in the long-run) toward levels that exceed marginal cost by the amount necessary to enable the typical firm to recover its joint and common costs. Significantly, this demonstrates that competitive prices are not purely a function of marginal cost. Instead, prices are determined by market forces, with the interaction of supply and demand determining the relative share of joint and common costs that are provided (over and above marginal cost) by different products and customer groups. This holds true in markets for many different types of goods and services – even where competition is only partly effective, and individual firms enjoy a substantial degree of market power.

Q. How does this discussion relate to this proceeding?

A. Because EnergyNorth is a rate-regulated monopolist, the Commission decides what prices are charged for gas delivery. Substituting for market forces or the interaction of supply and demand, the Commission decides how the Company's costs will be recovered during the revenue allocation and rate design phase of each case.

Many of the costs included in the Company's revenue requirement are fixed or sunk. Accordingly, prices set equal to marginal cost will likely fail to recover the Company's revenue requirement, assuming marginal cost is accurately estimated over the short- to long-run. Typically, there is little or no controversy concerning the recovery of short-run marginal costs, which are primarily variable costs that can be clearly and unambiguously be traced directly to specific customers. For instance, there is usually very little controversy concerning the appropriate price a utility should charge for the natural gas it purchases from an interstate pipeline and delivers to its customers. Most parties will readily agree that it is reasonable to charge a price that closely approximates the short-run marginal cost of gas – an amount which is approximately equal to the amount EnergyNorth pays for gas received during the hour when it is consumed. Any complications in deciding what to charge different customers will usually be a function of differences in customer usage patterns, and corresponding uncertainties concerning the precise timing of when each customer's gas was purchased (since gas prices fluctuate daily, and because gas can sometimes be purchased in advance and stored for use during peak hours).

Recovery of the cost of purchased gas is relatively straightforward. It is more difficult to determine how much each customer should be charged for using pipes and other facilities that are buried underground and shared by hundreds or thousands of different customers. Among other complicating factors, customers are in different locations (some are closer to the interstate pipeline, some are farther away), and they may use gas to a different extent during different times of the day and year. Consequently, EnergyNorth's distribution system gives rise to both fixed and sunk costs, and – due to economies of scale and scope – it inherently involves the problem of joint and common cost recovery.

To understand why I say this, consider first the way costs can be incurred jointly across time. In fact, as EnergyNorth installs gas distribution mains, it adds delivery capacity in fixed proportions across different times of the day and different months of the year. Even if a capacity addition is motivated by a need to increase capacity during the peak hour, the same amount of additional capacity will become available to serve load during other hours of the day, as well. Similarly, in the long-run, when capacity is increased or decreased in response to changes in winter gas usage, capacity in the summer will increase or decrease by the same amount. Hence, gas delivery during off-peak hours can be thought of as a byproduct of delivery during peak hours, and summer gas delivery can be viewed as a byproduct of winter gas delivery.

The pervasive existence of fixed and sunk costs, compounded by a joint cost problem across different time periods and geographic locations, results in a situation where very few costs can be reduced or avoided if any single customers' usage increases or decreases by a small amount. In other words, the marginal cost of delivering a little more or a little less gas to a typical customer will be relatively close to zero. Even the long-run incremental cost savings that would be achieved if a typical customer were to discontinue their gas usage entirely (permanently leaving the system) might be very small compared to the average cost of serving a typical customer. Under these circumstances, prices cannot be set equal to marginal cost and still generate enough revenue to recover EnergyNorth's total costs.

Q. What is the solution to the joint cost puzzle?

A. The answer is straightforward, but not obvious: in competitive markets, relative levels of value – or benefits – largely determine the share of joint costs recovered from each of the joint products. If two products are jointly produced, the most valuable product, or the one that receives the largest benefit from the joint production process, will pay the largest share of the joint costs. The least valuable product, or the one that receives the smallest benefit from joint production, will pay the smallest share.

Recall that joint costs are incurred when production processes yield two or more outputs in fixed proportions. Two classic examples are the production of beef and hides and the production of cotton and cottonseed. The costs of raising and slaughtering cattle are part of a joint production process that produces both meat and hides, in relative proportions than cannot easily be adjusted by the cattle farmer. Similarly, cotton and cottonseed oil are both part of a joint production process, in proportions that cannot be easily adjusted.

The cost of fattening and slaughtering cattle are paid by consumers of both beef and hides, while the cost of growing and harvesting cotton are recovered from consumers of both cotton and cottonseed oil, in proportions that depend on the relative value of each of the joint products (not their respective marginal costs). For example, if hamburger is not highly valued (because consumers don't particularly like hamburger, or they prefer chicken or seafood), but leather is highly valued, a surprisingly large fraction of the cost of cattle feed may be borne by the purchasers of leather goods. Similarly, if the purchasers of gloves are willing to pay more for leather gloves than for cloth gloves, they may end up paying a relatively large share of the cost of cattle feed while the purchasers of cotton gloves may pay a relatively small share of the cost of growing cotton (and consumers of cottonseed oil may pay a larger share than might otherwise be expected).

Once the solution to the joint cost puzzle is explained, for many people it will seem intuitively logical and fair. The purchasers of both leather gloves and hamburgers benefit from the joint production process so it intuitively makes sense that both will contribute to the cost of joint production. Similarly, the demand for both beef and leather products is strong, so it seems logical that market forces would lead to both consumers of both sets of products to contribute toward the joint costs of raising and slaughtering cattle.

Different customers pay different amounts, depending on how much benefit they derive from the joint production process. Those consuming the most highly valued products (for which demand is strong) will pay the largest share of the joint costs, while those those consuming the least valuable products (for which demand is weak) will pay the least. This principal applies not only to the distinction between beef and hides, but also to different types of beef, or different sections of the hide. A customer that purchases hamburger will end up paying more per pound toward the joint costs of cattle production than one who purchases standing rib roast or filet mignon.

Q. Does joint cost recovery differ when one of the products is primarily driving production decisions and the other product is a mere byproduct?

A. No. Even if cottonseed is just a minor byproduct of the production of cotton that is used in manufacturing T-shirts and bed linens, the cottonseed is valuable, so it will not be discarded. Instead, the seeds will be converted to cottonseed oil, and consumers of this byproduct will make a contribution to the joint costs of raw cotton production. The status of one item as the primary product and the other as a byproduct does not change the pattern of cost recovery, nor does it indicate that consumers of the main product will pay nearly all of the joint costs. If the byproduct is valuable, purchasers of the byproduct will benefit from its production, and they will contribute toward the cost of the joint production process. Succinctly stated, the strength of demand for the byproduct will determine how much those consumers pay toward the joint costs.

A somewhat analogous joint cost phenomenon arises geographically within EnergyNorth's system, since the same pipe can be used to deliver gas to more than one location. Furthermore, pipes are manufactured in "lumpy" sizes, and their installed cost involves substantial economies of scale. If a 4" main is not quite adequate to serve the anticipated future usage of customers in a particular neighborhood, the next largest size considered might be a 6" main, which provides more than double the capacity with only a small increase in the installed cost per linear foot. If the 6" main is installed it will have substantial excess capacity that will be available to accommodate growth in usage in other locations. This is another example of the joint cost phenomena, analogous to an increase in beef production creating an increase in the volume of hides that become available for tanning and sale to leather purchasers.

Q. How do joint costs relate to common costs?

A. Joint costs are simply a special type of common cost. To the extent common costs vary in proportion to output, they will be recovered in competitive markets in the same manner as direct costs: they become part of the marginal cost of producing each individual product, and will therefore directly impact prices (since prices tend to equilibrate towards marginal cost). However, production processes sometimes include common costs that give rise to significant economies of scale or scope. The recovery of common costs will, to that degree, follow the same pattern as the recovery of joint costs.

Since joint costs occur don't have an impact on marginal cost, the way they are recovered is on the basis of demand characteristics (value and benefits). Similarly, if economies of scale and scope are pervasive in a common production process, a markup above marginal cost will be necessary for the firm to stay in business. Market forces will lead to equilibrium conditions in which the price of each product will exceed the marginal cost of producing that product by an amount that depends on supply and demand conditions for that product. In essence, the markup recovered from each product will depend on how much the product is valued by consumers (or the benefit obtained from producing it in common with other products). Assuming equilibrium, on an overall basis, the contribution from each product, over and above recovery of its marginal cost, will be just enough to enable the firm to recover its total costs and stay in business.

Q. Can you please elaborate on differences in the amounts that will be paid by different customers toward the recovery of joint and common costs?

A. Yes. The portion of the joint and common costs that are recovered from different products or services will vary depending upon supply and demand conditions. More specifically, the relative cost-recovery shares will depend on the degree to which purchasers of different products benefit from the joint production process, the value of the different products, and the relative strength of demand for the different products. In other words, a uniform markup will not be added to marginal cost, and each customer will not contribute a uniform dollar amount toward the recovery of joint common costs. Instead, joint and common cost recovery will vary widely. Larger customers will tend to contribute more than smaller customers (because they use more, and therefore benefit more from the common production process). Similarly, more valuable products will tend to have a larger markup, resulting in a contribution toward joint and common costs than less valuable products.

In general, the amount contributed by specific customers (or specific products) will vary depending on the strength of demand in the different markets and submarkets. The stronger the demand – and in that sense, the greater the benefit received from the joint production process – the greater the share of joint costs that will be borne by any particular product, service, customer, or customer group. If General Motors incurs common costs when producing Chevrolet and Cadillac automobiles, to take advantage of additional economies of scale or scope, we can confidently predict that a larger share of the common costs will end up being recovered through a large markup above marginal cost built into the wholesale price of each Cadillac, while a smaller share of the common costs will be recovered in the wholesale price of each Chevy.

Q. You've also mentioned sunk costs several times. How do they relate to this discussion?

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A. There are some striking similarities between joint costs and sunk costs. Once they are incurred, sunk costs are irrelevant to the pricing process. However, the mere fact that some costs are sunk does not mean the firm has no chance of recovering those costs, or will be forced out of business. The cost of writing a novel provides a good example. The actual amount of time and effort invested the writing process by a novelist is entirely irrelevant to what the writer will be paid for their work. Once a novel is written, the cost of creating the novel is sunk and irretrievable. Assuming a competitive market, this sunk cost will have no bearing on what publishers will bid for the right to publish the novel.

Similarly, once a publisher purchases the rights to a novel, the amount it pays for those rights, the cost of hiring an editor to work with the author in polishing the manuscript, the costs of typesetting, and various other costs leading up to and including the cost of the initial print run become sunk costs as they are incurred. These sunk costs are irretrievable and irrelevant to any subsequent pricing decisions. Not only will they have no bearing on the price the publisher asks for copies of the novel, they will little or no impact on how many copies are ultimately sold – that will depend almost entirely on how good the novel is, and how popular it becomes.

None of this suggests that sunk costs are never recovered. Successful authors are paid well for their work. If they were not, fewer novels would be created, and publishers would be forced to bid up the price paid for any novels that continue to be written. Market forces ensures that novels continue to be written and publishers continue to take a chance on publishing new books, despite the risk that their costs will be sunk, and may not be recouped. The parallel is clear: sunk costs incurred by any one author or publisher have no impact on marginal cost, and thus they have no impact on prices, yet these costs are often recouped, ensuring that novels continue to be written and published.

Q. What determines whether, and how, sunk costs are recovered?

A. Value. For instance, the sunk costs of producing a book will be recovered only to the extent the book itself has perceived value. The amount paid for each individual copy, and the total number of copies that are sold, will depend on the market for novels and the extent to which there is demand for this particular novel. If the novel is entertaining and well written, if it features interesting characters and a plot that people like, word will spread, and many copies will be sold at a price that customers consider to be fair for the value they receive. If enough people are eager to buy the book, they will pay a price that greatly exceeds the marginal cost of production (say, the cost of printing and binding one more copy in the course of a large print run). If the book is a dud, most of the copies will be destroyed, and the rest will linger on the "remainders" table, after being marked down to a price that is below the marginal cost of production. Either way, the sunk costs incurred by the author and publisher will be entirely irrelevant to the price-setting process. In first case, prices will generate revenue far in excess of the sunk costs; in the second case, prices will fail to recoup any of the sunk costs. The key factor is the difference in value, as reflected in the market outcome.

Q. Are you arguing that the Commission should set gas delivery rates in the exact same way competitive markets determine the price of novels, or beef and hides or Cadillac and Chevrolet automobiles?

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A. No. The Commission has considerable flexibility in deciding how to price EnergyNorth's services, and I am not suggesting it should follow precisely the same pattern that explains how joint and sunk costs are recovered in competitive markets. However, the patterns observed in competitive markets are highly relevant and instructive, and they should be evaluated by the Commission, along with other considerations. To give just one example, it might be argued that prices should be relatively uniform, for reasons of simplicity, or administrative convenience, or to ensure consistency with the results of a particular cost study. However, in competitive markets joint and common costs are never recovered on a purely uniform basis, since this would be sub-optimal. As a general rule, market-based prices do not recover an identical monthly dollar amount from each individual customer toward recovery of fixed or joint costs, nor do they typically result in a uniform percentage markup above the marginal cost of producing each product.

When large differences exist in the benefits received from customers of different sizes or types, competitive prices will generally deviate from uniformity in order to take into account those differences. For instance, Ford produces multiple different car models in a common production process. By using the same transmission and other key components on more than one model, Ford can spread the recovery of the fixed costs of engineering and design, and the fixed costs of machine tooling for those common components across multiple different cars. This allows it to further exploit economies of scale and scope. As a result, a disproportionate share of Ford's profits is generated by higher-end models which are loaded up with accessories and luxury packages that are highly valued by some customers. Those customers are willing to pay a much higher price for cars with these enhancements (well in excess of the marginal cost of adding these enhancements). Consistent with economic theory, these customers provide a much larger contribution toward Ford's sunk, joint and common costs. Other customers, who don't value these features as highly, or who cannot afford them, purchase lower-end models which provide a much smaller contribution toward Ford's joint and common costs.

While Ford's motive in marking up prices for different car models by different amounts is a desire to maximize profits, the end result is beneficial to society as a whole. Differential markups enable lower income consumers to purchase newer, more reliable transportation, and it helps Ford produce more cars and employ more people than if it applied a uniform markup above marginal cost on each car model. Applying different markups to different models allows Ford to sell more cars more profitably, including sales made to customers who perceive relatively little benefit from owning a new car, and customers who can only afford a stripped-down version of the basic product – one that most consumers wouldn't be satisfied with.

One way of thinking about this competitive pricing process is to recognize that optimal prices involve the interaction of both supply and demand – like two blades of a scissor which cut paper much more effectively than a single blade on its own. The key takeaway is that competitive prices take into account more than just differences in marginal cost. The demand side of the equation (differences in the benefits or value received by different types and sizes of customers), are also important.

Similarly, the Commission can (and should) use its discretion to decide how far specific prices should be set above marginal cost. More specifically, I recommend reducing EnergyNorth's customer charges, and increasing the volumetric rates, thereby improving the alignment with differences in the value received by large and small customers, and better advancing important public policy goals, including fairness and encouragement of economic efficiency and energy conservation.

IV. THE COMPANY'S MARGINAL COST STUDY

Q. What role did the marginal cost study play in the Company's pricing proposals?

A. This study is virtually the only evidence offered by EnergyNorth to support its proposed revenue allocation and rate design in this proceeding. The justification for placing so much emphasis on this study was explained as follows:

> A well-established principle of economic theory is that the price of a good that is sold in a perfectly competitive market will be set at the marginal cost to produce that good. It is a further well- established principle of economic theory that the best allocation of resources will occur, and the best consumption decisions will be made, in an economy in which the prices of goods are set at marginal costs.
>
> It has been the Commission's rate-design policy and precedent since the mid-1980s to apply the concepts of marginal cost pricing in a rate case (a) to determine the share of total rate case revenue requirement for which each rate class is responsible, and (b) to set base distribution rates in order to promote appropriate price signals and, therefore, proper energy consumption decisions. The basis for the Company's current allocation of revenue requirement to classes, rate design, and current rate classifications was approved by the Commission in Order No. 23,675 (Apr. 5, 2001) in the Company's 2000 revenue neutral rate design proceeding, Docket No. DG 00-063.[17]

17 Direct Testimony of Melissa F. Bartos, Pages 2-3.

Q. Have you reviewed Order No. 23,675?

A. Yes. A marginal cost study was filed in that case (and in subsequent cases) and was accepted in the settlement agreement that resolved that proceeding. Based upon my reading of the order, the cost study does not seem to have been a primary focus of attention. Rather than extensively debating details of the marginal cost study, the parties seem to have primarily focused on specific rate issues, including the level of customer charges, the introduction of a load factor-based rate structure and Cost of Gas clause, and an effort to reduce rates charged Commercial and Industrial customers without unduly burdening Residential customers.

The Company explained it wanted to move toward "cost-based rates" and facilitate increased retail competition, but the primary focus of the parties seems to have been on the proposed rate changes. It isn't clear how carefully the parties examined the inner workings of the cost study that was submitted in that proceeding, but the details of the study were not pivotal to the settlement agreement, nor was there any discussion of the inner workings of the study in the Commission's order. Furthermore, OCA and other parties expressly reserved the right to argue for a different cost of service methodology in future proceedings.

Q. Did the Commission discuss or endorse the details of the marginal cost study in its order?

A. No. The marginal cost results are briefly mentioned in the order, and they undoubtedly played a role in the Commission's decision, but there is no indication the details of the underlying methodology was being endorsed.

> We note that the target marginal cost-based class revenue served as a guide in establishing the Settlement rates. Had the Settling Parties and Staff fully reflected the results of the marginal cost studies in the ratemaking process the rate increase for the Residential classes would likely exceed those that were proposed. For example, the Settling Parties and Staff recommended monthly customer charges of $10.00 and $7.00 for Residential Heat and Residential Non-heating customers respectively... considerably short of the $22-23 shown in KeySpan's marginal cost study. ...
>
> Further, while a 6% increase in the revenue requirements for the Residential Heating Class and a 13% increase for the Residential Non-Heating class appear substantial, one must also consider the monthly bill impact and the fact that KeySpan custoemrs have not had a base rate increase since April 1, 1993. ...
>
> The statutory standards ... do not require that the Commission determine the outcome using any specific methodology, so long as the result is consistent with the "public interest" and the rates are "just and reasonable." ...
>
> We believe that an "end result" review is particularly applicable to the consideration of settlement agreements, which, by their nature, often require parties to compromise positions and principles in order to reach an acceptable outcome. Thus, while the Commission ... must condut its own independent review in order to ensurethat the "public interest" and "just and reasonable" standards have been met, it may do so without reliance upon any particular theory or methodology.[18]

Q. Can you briefly summarize your overall reaction to the cost study in this proceeding?

A. While there are several aspects of the Company's cost study I disagree with, the most fundamental problem is the severe lack of consistency with economic theory. These

18 New Hampshire Public Utilities Commission, Order No. 23,675, April 5, 2001, pages 22-24.

inconsistencies include a failure to draw meaningful and appropriate distinctions between fixed or sunk costs and variable costs, and a failure to maintain these distinctions in an internally consistent, logical manner. The effect of these inconsistencies is to increase the customer-related cost estimates relative to the demand-related cost estimates.

This problem is further compounded by the questionable manner in which some of the statistical equations were developed, which involved an unacceptably high degree of "data mining," an excessive reliance on dummy variables, and the lack of theoretical support for the dummy variables. The combined impact of the theoretical and statistical problems are so severe, they completely invalidate any conclusions that might otherwise be drawn from the study.

A. Inconsistencies with economic theory

Q. Did the Company adopt a clear, consistent definition of planning horizon or "run" that it studied?

A. No. Ms. Bartos never explicitly states what "run" or planning horizon she intended to study, and neither the word "run" nor the phrase "planning horizon" appear anywhere in her testimony. I did find the phrase "Long-Run Unit Costs" used as a label on line 1 of Attachment MFB-8, page 1, and this cryptic reference suggest the intent was to study some sort of long-run costs, not short-run costs.

As I indicated earlier in my testimony, the planning horizon or "run" is crucially important. Both as a theoretical matter and as an empirical matter, when looking at a well-designed marginal cost study for a gas utility, one can expect to see lower low cost estimates the shorter the planning horizon that is evaluated, since the shorter the "run" the greater the extent to which sunk costs will dominate the calculations (assuming they are correctly developed). Conversely, when looking at long-run studies, one can expect to see higher marginal or incremental cost estimates – especially if a "scorched earth" or "extreme long-run" scenario is modeled, which assumes there are very few, or no, sunk costs.

When the "run" is not clearly and consistently stated, or a mixture of different planning assumptions or time-horizons are used in different aspects of a marginal or incremental cost study, one can expect the results to be highly dependent upon specific assumptions and details concerning what is treated as fixed and what is treated as variable. This was the situation I encountered when examining the Company's study in this case. The Company completely ignored the fact that a service line, regulator and meter have already been installed at most building along the routes where EnergyNorth has distribution mains in New Hampshire. The cost of these items is almost always sunk and unavoidable once they are installed. In the case of a typical existing building, which is already connected to the system, if the building sits vacant for a while, the cost will not be reduced just because the service line isn't being used. If a new owner or tenant moves into the building and requests gas service, the Company will add another customer to its rolls, but the cost of these facilities will not increase. If the customer then remains on the system, the cost will not change. Finally, if the customer subsequently leaves the system, the cost will not decline.

This sunk cost problem was completely ignored when the Company developed its cost estimates for service lines, regulators and meters. Unlike the statistical approach it used in studying other costs, the Company adopted a "scorched earth" approach to cost modeling, which is entirely based on engineering cost estimates, and gave no consideration to the extent to which customer-related costs are actually at "the margin." In the context of EnergyNorth's system, this approach is only logically consistent with an extreme long-run planning horizon. A far less extreme version of the long-run was used in the rest of the study, where a statistical approach was used to estimate the degree to which costs are increasing due to main reinforcements and main extensions.

The explanation provided by Ms. Bartos glossed over these inconsistencies, but this brief passage provides a good entry point for explaining them in greater detail:

> I prepared calculations and analyses to estimate the marginal distribution function-related costs that the Company would incur to serve (a) additional demand when the Company is experiencing design day conditions, and (b) additional customers.

At least two things are noteworthy about this brief explanation. First, she exclusively refers to "additional" demand or customers, meaning the increases in total cost that potentially would occur if there were to be an increase in design day demand or an increase in the number of customers. She makes no mention of how much costs decline when customers conserve energy or reduce their design day demand, or how much total costs decline when an existing customer leaves the system. Second, she separates her calculations and analyses into two broad groups, corresponding to the pricing distinction between volumetric rates (which are supported by her cost estimates for "additional demand when the Company is experiencing design day conditions" and customer charges (which are supported by her cost estimates for "additional customers."

Upon further investigation, I confirmed the study is exclusively focused on how costs change when the volume of output increases. No attempt was made to examine how much costs decrease when an existing customer leaves the system, or when an existing customer reduces their energy usage or design day peak demand. This failure to consider the rate of change in the downward direction compounded some other flaws I found in the study. This may also help explain why the Company didn't notice any of the problems with adopting a purely hypothetical "scorched earth" approach to modeling the cost of service lines, regulators and meters. If did not examine how much costs decline when a customer leaves the system (e.g. when a building becomes vacant or a customer switches to a geothermal heat pump). Thus, it completely ignored the "ratchet" phenomenon – the fact that investments in services, regulators and meters are sunk once they are installed at a specific building. They do not increase or decrease with changes in the number of customers receiving gas service at that location.

Q. Why is the change in total cost as output decreases relevant?

A. In part, it is relevant because the study results have been labeled as "marginal cost" estimates. Since the term "marginal cost" is taken from the economic literature, the validity of the Company's cost estimates and underlying assumptions, should be judged in that context. Under the simplest conditions considered in economics, where he cost function is smooth and continuous, and cost is the same whether it is measured by how much total cost increases as output increases by an extremely small amount, or how much total cost decreases as output decreases by an extremely small amount. If this equivalence cannot be confirmed, it should be taken as an indication that may be flaws in the modeling approach, or there are complexities that need to be carefully evaluated and resolved.

These complexities arise when the cost function is not smooth and continuous, because of lumpiness, “ratchet” effects, or other complications. Where those complications are known to exist (or are encountered during the modeling process), they need to be dealt with appropriately. A good starting point is to evaluate how much costs change when output is varied by different amounts, or in different directions, or in different geographic locations. To the extent the cost estimates vary significantly, it becomes necessary to decide on the most appropriate solution. Should these disparate results be averaged? Should they be blended, with different weights given to different cost estimates? Or, should different prices be developed which are applicable to the different situations which give rise to different costs?

From my perspective as an economist, the least desirable and least logical solution is to simply ignore the problem. In the case of the service lines, the effect of ignoring the sunk cost problem is to effectively treat every customer as if they were “at the margin” – equivalent to the relatively rate situation facing a potential customer that is thinking about constructing a new building and they need to decide whether to use natural gas. Since this situation is not the one confronting most people most of the time, it obviously deserves less weight than the more common situation where someone is occupying an existing building, or thinking about moving into an existing building, with an existing connection to EnergyNorth's distribution system.

For most customers and potential customers, the situation where the service line doesn't exist is a purely imaginary or hypothetical scenario with little relevance. The decisions most people will make in response to the prices set in this proceeding will not involve any action or potential action that puts the service line, regulator and meter at the "margin" of decision-making. In terms of economic efficiency and public policy, the most relevant question for designing rates is how much costs will actually increase or decrease at the margin when someone decides whether to use gas, or how much gas to use, while occupying a building that is already connected to the system. For those customers, the cost of the service, regulator and meter will typically be a sunk cost, which is irrelevant from the perspective of optimal pricing policy.

One exception, where the cost is not fixed or sunk, occurs when someone builds a new home or business. Another exception occurs when gas service is being extended for the first time to their neighborhood, and they decide whether to connect to the system. Since those exceptions are less common than the situation where the building is already connected to the system, the overall system-wide level of long-run marginal costs should give much more weight to the typical situation, where these costs are sunk.

Q. Is the proportion of sunk costs uniform throughout the system?

A. No. Sunk costs are most prevalent where facilities are used by just one or two customers, and they are less prevalent where facilities are shared by hundreds or even thousands of customers. The logical connection between the degree of cost-sharing and sunk costs is straightforward. Recall that long-run marginal cost is the rate of change in total costs that occurs in a planning horizon where many capital costs are potentially variable. The more customers that share a particular piece of equipment, the greater the likelihood that increased usage by any one of those customers can create "congestion costs" or opportunity costs which impact hundreds or thousands of other customers. Congestion occurs whenever the demand placed on shared equipment begins to approach its design capacity. Conceptually, this is somewhat analogous to a bottleneck in an assembly line, which impacts the productivity of every worker and every piece of equipment that is downstream from the congestion point. When congestion begins to occur within a widely shared part of the system, expanded usage by even a single customer can adversely affect the safety and reliability of service to other customers on the system. When congestion begins to become a concern, the marginal cost begins to increase, based upon the increased probability of encountering problems which would adversely impact the safety and reliability of service to many different customers. If insufficient capacity exists to fully accommodate fluctuations in and potential growth in demand, the marginal cost curve will turn sharply vertical, as the probability of unsafe conditions or inadequate operating pressure begins to escalate.

Because reliable utility service is vitally important to most customers, the cost to customers, and society, of being unable to supply gas when it is needed can be extremely large. This is analogous to the risk of a tornado, or hurricane, or fire, where a very large problem is multiplied by a very small probability – which explains why people pay for insurance even though there is very little risk they will encounter a problem during any one hour or day. The probability-based costs associated with potential system congestion or inadequate capacity become part of the marginal cost to society associated with providing gas service to every customer who can potentially be affected by the problem. This logically follows because an increase in peak usage by any customer downstream from the point of congestion could trigger problems for many other customers. Similarly, a reduction in usage by any downstream customer can help alleviate the problem, reducing the risk of a problem. Under those conditions, the reduction in usage by any one customer will reduce the marginal cost of serving all of the other customers on that part of the system, and vice versa.

These societal costs are one of the reasons regulations exist which require utilities to provide safe and reliable service. Even if this were not required, it would be in the best interest of the gas company to install ample capacity wherever it might be needed, in order to reduce the potential for future congestion problems. However, building adequate reserve margins throughout the system is costly, and this should be considered when estimating the long-run marginal cost of meeting design day demand. These congestion-related societal costs are highly relevant in the context of distribution mains and other widely shared parts of the system, and of much less relevance to a service line that only impacts a few customers.

Q. How are capital costs handled in a valid long-run marginal cost study?

A. Basically, a valid long-run marginal cost study considers the rate of change in the total cost function as the size, design and capacity of the capital investment is varied and optimized, along with corresponding variations in operating costs. This optimization analysis is supposed to be performed in the context of a long-run "planning horizon" which is not excessively tied to, or unduly constrained by, limitations and characteristics of the existing system. In other words, rather than focusing on the "worst case" scenario of what would happen if problems arose and no effort were made to resolve them by making new investments, the assumption in a long-run planning horizon is that new investments are made that avoid these problems, taking into account growth and replacement needs over the long-run.

As I indicated earlier, an appropriate long-run planning horizon for EnergyNorth would correspond to the degree to which capital investments can potentially be varied over a typical 10 to 20 year planning horizon. Over this time period, EnergyNorth's distribution mains would not be classified as entirely fixed or sunk, but instead should be treated as being variable to a substantial degree. For instance, over this time period new mains will need to be installed along some routes, where older, existing mains are nearing the end of their useful life, or becoming unacceptably leak-prone. This impacts the long-run marginal cost of all of the customers sharing those facilities.

Similarly, over a 10 to 20 year time period, even if system-wide average consumption is stable, there will be pockets of growth in some areas, and declining usage in other areas. Accordingly, congestion will likely arise in some areas which can be resolved by replacing the existing mains with larger ones, reinforcing the route with a second main, or upgrading parts of the system to operate at higher pressures. None of these options is entirely cost-free, of course, and the costs of the optimal solution will be reflected in the marginal cost of serving every customer using those mains.

EnergyNorth has the opportunity to optimize many capital-related decisions over a 10 to 20 year planning horizon. For instance, it can decide whether to reinforce, replace or retire some of its existing mains, and it can select the optimal size of each newly installed or reinforced main over its economic life. For locations where capital investments can be optimized, the cost of installing, reinforcing or replacing mains may be relatively high (compared to the cost of existing mains) on a per-linear foot basis, due to inflation and other factors, like the difficulties involved with installing new mains in areas where older mains, water lines and other infrastructure already exists.

Of course, in a location where the existing main is relatively new, it has many decades of useful life remaining, and the route has ample capacity to meet all foreseeable demand for that entire time period, the capital-related costs of the main may appropriately be classified as fixed or sunk. In those locations, the capital-related cost of distribution mains may be very low, especially if the main cannot be adjusted or optimized to serve some other purpose over the relevant planning horizon. Accordingly, an analysis of the overall system-wide level of long-run marginal costs of distribution mains will represent a composite of relatively high costs in some locations and relatively low costs in other locations.

B. Flaws in the Statistical Cost Estimates

Q. What approach did the Company use to estimate the marginal cost of distribution mains?

A. Unlike its approach to the cost of facilities at or near the customer's premises, the Company used a statistical approach to estimating the marginal cost of other parts of the system. The general approach is captured in the following passage in the direct testimony of Melissa Bartos:

> I asked the Company to prepare an engineering study of forecasted system reinforcement projects that the Company would be required to construct from 2016 to 2026 to meet the Company’s projected design day demand during that period. The engineering study that I asked the Company to

> prepare is different from the Company's actual distribution asset plan, which takes into account (a) projects that will be required to meet projected load growth, (b) projects that are included in the Company's Cast Iron Bare Steel ("CIBS") replacement program, and (c) other distribution replacement and relocation plans. The Company's distribution asset plan is different from the projections that I requested because the actual asset plan may combine a reinforcement project with a CIBS replacement project or other replacement or relocation projects, which is likely to affect the timing and location of reinforcement projects.[19]

This is virtually the entirety of the conceptual or theoretical support offered for this approach. The remainder of the explanation is focused on the specific data that was used, and the statistical approach that was used to analyze this data. No explanation was offered concerning the portion of the overall system-wide total cost of mains that was effectively being treated as fixed or sunk, and no explanation was given for why the Company used a fundamentally different approach to estimate the cost of services, regulators and meters.

While the offered explanation is rather cryptic, when it is considered in conjunction with the Company's work papers, it is clear that some of the cost of distribution mains is implicitly being treated as fixed or sunk. In effect, the cost estimates developed by the Company represent a composite of relatively high costs for mains in locations where growth is occurring, or mains need to be replaced or relocated, and relatively low (or zero) costs for mains in the remaining locations. While I don't find this approach objectionable in principal, I am troubled by some aspects of the actual calculations.

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19 Direct Testimony of Melissa F. Bartos, Pages 9-10.

Q. Do you have any concerns regarding the statistical approach used by the Company?

A. Yes. There are two closely related problems which obliterate the validity of the statistical results. The first major problem is that some potentially important explanatory variables were not evaluated. Because variables that are potentially important (on theoretical grounds) were never evaluated, it is difficult or impossible to judge the statistical validity of the other variables that were included in the analysis. The second major problem is closely related: data mining was used to evaluate far too many "dummy" variables – including variables for which no "a priori" theoretical basis exists to justify testing them. Both problems are very serious, and make it impossible to have any confidence in the validity of the statistical results.

Q. Can you briefly explain the statistical approach used by the Company to analyze the cost of distribution mains?

A. Yes. A single statistical tool – called linear regression – was used for to study the cost of main reinforcements and extensions.

> I prepared a regression analysis to estimate the statistical relationship between the projected cost of system reinforcement projects and projected design day demand. The regression equation that I estimated is provided in Attachment MFB-1, page 3.
>
> I prepared a regression analysis to estimate the statistical relationship between the cost of main extensions and design day demand, based on the historical data from 1989 to 2016. The regression results are summarized in Attachment MFB-1, page 4.[20]

20 Ibid, page 10.

Linear regression is a popular statistical technique that is frequently used to model the relationship between a scalar dependent variable (typically referred to as "Y") and one or more explanatory variables (also referred to as independent variables) which are typically denoted as "X" (or X1, X2, X3...). In this context, the dependent variable is the cost of installing distribution mains, and the explanatory variables are the factors which help explain why those costs are high in some years, or some locations, and low in other years, or other locations.

Q. Why is it a problem to exclude important explanatory variables from a regression analysis?

A. Linear regression works best when adequate data is available that captures every significant variable that helps explain, or "cause" fluctuations in the dependent variable. In the case of distribution mains, that suggests it would be preferable, if at all possible, to obtain and use data concerning any potentially important explanatory variable that might be varying from year to year, or location to location. For instance, it would be helpful to obtain data from work orders, engineering records, or other internal sources that indicates the extent to which mains were installed under streets (which is potentially more costly and time consuming, and requires restoration of the paving when completed). Similarly, it would be helpful to obtain data that could be used to evaluate the extent to which mains were being installed in urban areas, compared to less congested rural areas. Similarly, it would be preferable to obtain data concerning the extent to which rocky conditions, or solid bedrook, was encountered on particular jobs, or along particular routes. Sound theory and logic suggests variations in these conditions could easily have a significant impact on the cost of mains installed in one year, or one location, compared to the cost of mains installed in different locations and different years.

If reliable data is not available for important explanatory variables, then the results of the linear regression will automatically impute the impact of those missing variables onto whatever variables are included in the analysis. For example, if the cost of installing mains in year one happens to be high and the cost in year two happens to be low, the goal of the statistical analysis will be to "explain" how much of the variation from one year to the next is attributable to the explanatory variables that are included in the regression analysis. However, if variables are missing, the regression will not account for, or "hold constant" those missing variables. Instead, the statistical software will attribute the fluctuation in costs to whatever explanatory variables happen to be used in the regression equation.

Sometimes, when needed variables are missing, the result will be a poor statistical "fit" – the regression will only explain a small portion of the observed variation in the dependent variable. However, this is not always the case. Sometimes instead, the result will be a fairly good statistical "fit" but the result will be inaccurate and misleading. For example, consider what would happen if a missing variable, like the amount of bedrock that is encountered, happens to be much larger in year one than in year two. If it also happens to be the case – by pure coincidence – that the capacity of the mains installed in year one happens to be larger than the capacity installed in year two, the statistical software will have no way of knowing what portion of the cost fluctuation is caused by differences in the amount of bedrock. Instead, it may attribute the entire difference in cost to the difference in design capacity, while in reality only a portion of the cost difference is actually attributable to difference in capacity. Succinctly stated, when data for important variables is missing, the regression results will not be reliable, imputing some of the cost fluctuations that are actually caused by missing variables to whatever independent variables are included in the regression.

Q. Did the Company acknowledge that there are explanatory variables that were not accounted for in its statistical analysis?

A. Yes. For example, the Company was asked in discovery to explain what other explanatory variables could impact main extension investments. It responded:

> There are many variables that could impact main extension investments, including: terrain, length of pipe installed, urban/rural area, type of pipe installed, diameter of pipe installed, paving requirements, and traffic detail requirements.[21]

Yet, none of these variables were statistically evaluated. The only justifications offered for excluding these variables from the analysis were "practical" concerns that potentially might have made it difficult to collect the data needed to evaluate some of these variables, and this claim:

> In addition, the purpose of this analysis is to identify the relationship between main extension costs and design day demand on an annual basis, not to predict main extension costs for individual projects.[22]

However, if these variables may be needed to accurately predict the cost of individual projects, they may also be needed to accurately predict the cost of projects that

21 Response to Request No. OCA 1-56 (c).
22 Ibid.

will occur in future years (since the mix of future main extension projects will not be identical to the particular mix that was observed in the historical time period).

Q. Can you explain your concern with respect to dummy variables?

A. Yes. Although Ms. Bartos doesn't mention the words "dummy variable" in her testimony, she used a lot of them. Looking at the final statistical equations used in the marginal cost study, I found an interactive dummy variable for the years 2018-2026 on Attachment MFB-1, page 3, a dummy variable for the year 2000, two different dummy variables for the years 2012 to 2016, and a dummy variable for 2002 to 2004 just on Attachment MFB-3, page 4, alone. I also found two different dummy variables on Attachment MFB-4, and an astounding 10 different dummy variables on Attachment MFB-5 page 1. I found additional dummy variables scattered throughout the other pages of the marginal cost study, including six dummy variables on Attachment MFB-5 page 3, five dummy variables on Attachment MFB-6 page 1, four dummy variables on Attachment MFB-6 page 2, four dummy variables on Attachment MFB-6 page 3 and one more dummy variable on Attachment MFB-6 page 4.

The sheer number of dummy variables that were used by Ms. Bartos calls into question the plausibility and reliability of her statistical results. From my perspective as an economist, dummy variables can be thought of as disappointing second-best solution that we sometimes resort to, because of the inadequacies of our data. The main problem with dummy variables is that they don't really "explain" anything. They can improve the statistical fit, helping to overcome weaknesses in the data, but they don't actually provide any additional insight into the underlying factual relationships that explain the phenomena being studied. In this instance, they don't help us identify and understand the important factors which cause a particular level of total cost to be incurred in one year and a different level of total cost to be incurred in a different year. In turn, since we don't know why total cost differs between two years, we can't accurately estimate marginal cost (how much of the variation relates to differences in the volume of output). Stated another way, if we aren't gaining a true understanding of what caused the level of costs during specific years, we aren't developing a reliable tool for predicting what level of total cost will be incurred during future years, or how much that cost will vary as a function of differences in demand.

When dummy variables are arbitrarily used to improve the statistical "fit" we don't know what would happen if the equation were applied to a different utility during those same years, or if it were applied to the costs incurred by the same utility during an entirely different time period, or in a different jurisdiction. In this case, these inherent weaknesses were greatly exacerbated by five additional, interrelated problems:

First, Ms. Bartos considered and rejected numerous additional dummy variables, including ones that were ultimately rejected, and were not specifically disclosed in the marginal cost study documentation. The only dummy variables that were reported were those she ultimately chose to include in the final equation, because they "improved" the statistical fit.

Second, the use of dummy variables exacerbated the problem I described earlier with respect to what happens when important explanatory variables are excluded from a regression analysis. Adding dummy variables makes that problem worse because it increases the risk of inadvertently imputing cost fluctuations caused by missing variables to one of the independent variables in final regression equation. The more dummy variables that are tested, the greater the chance some of them will appear to be significant, yet they are merely picking up some of the unexplained cost fluctuations that are attributable to the missing explanatory variables.

Third, all of the dummy variables were evaluated on a purely statistical or "end result" basis. No *a priori* basis existed for testing many of these variables, and none of variables included in the final equations is justified on the basis of sound theoretical reasoning. Absent a sound, independent theoretical justifying a dummy variable, there is no reason to assume the variable is anything more than a statistical artifact of the particular data set that was used in developing the equation. The closest Ms. Bartos comes to providing a theoretical basis for her dummy variables was to note that ownership of the Company changed several times during the historical time period used in her analysis.

> I also tested each equation to look for "structural shifts," which are changes in the relationship between the Cost Variable and Cost Driver variable starting in a specific year and continuing for a number of years. I specifically looked for structural shifts that might have been related to the acquisition of EnergyNorth by KeySpan in 2000, the later acquisition of KeySpan by National Grid in 2007, and the acquisition of EnergyNorth by Liberty in 2012.[23]

However, Ms. Bartos had no basis in theory to anticipate whether costs would increase or decrease after any particular change in ownership. If they happened to increase or decrease around the same time as the change in ownership, she had no way of

23 Direct Testimony of Melissa F. Bartos, Page 5.

determining whether the change in costs was related to the change in ownership or purely coincidental. Conceivably, if costs increased after a change in ownership, it might be attributable to a greater corporate desire to build up the rate base. Conversely, if costs decreased after a change in ownership, it could conceivably be due to a greater commitment to cost control by the new management team.

The problem with not having sufficient *a prior* justification for using these dummy variables was compounded by a failure to collect additional evidence to evaluate what was causing costs to be different during these particular time periods. Ms. Bartos apparently made no effort to determine whether observed changes in costs that occurred around the time of an ownership change were attributable to something related to the ownership change, or something else entirely, like a larger or smaller fraction of new mains being installed in areas with a lot of bedrock, or in municipalities with costly traffic detail requirements.

Fourth, Ms. Bartos did not limit her exploration of dummy variables to specific time periods associated with each change in ownership. Instead, she explored numerous other time periods that were just loosely associated with the changes in ownership:

> However, I did not limit the potential structural shifts to these years. If I determined that a Cost Variable may have a structural shift, I tested additional regression equations that allowed the slope and/or intercept terms to be different for the time periods before and after the time of the potential structural shift.[24]

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24 Ibid, Page 6.

Whatever the intent, this procedure was effectively a form of "data mining" and as a result, the statistical equation were driven by the data set, rather than using theory to develop the variables and using the data set to test the theory.

Fifth, Ms. Bartos arbitrarily assumed that the statistical results for the most recent time period would be applicable to future years. This is not a valid assumption given the approach she used.

> If a structural shift was found to be significant, I used the slope associated with the latest (i.e., most recent) time period as the marginal cost estimate because, all else being equal, costs from the most recent time period are expected to be more representative of costs in the future.[25]

In fact, the change in costs that occurred during the most recent few years might be attributable to some unique combination of unknown factors that happened to occur during those years – something entirely unrelated to the change in ownership, but some other phenomena that may or may not persist in future years. Accordingly, her equations do not provide us with any confidence that they can meaningfully predict what level of total costs will be incurred during future years, or how much those costs will vary at the margin. This follows directly from the fact that we have no way of predicting whether the unique combination of unknown causal factors that occurred during recent past will also occur to the same extent, and in the same combination, during future years. Especially given the large number of different dummy variables she considered and used, it is very likely that each of the time periods and sub-periods she studied has a unique combination of causal factors that happened to occur during those particular years.

25 Ibid.

Future years will have their own unique combination of causal factors, which will not precisely replicate that of the most recent historical period, or any other specific prior period.

By failing to collect enough data related to the underlying causal factors that actually explain fluctuations in cost from year to year, and by experimenting with different dummy variables to find ones that closely conform to those fluctuations, it becomes impossible to know whether, or to what extent, causal conditions in future years will resemble those that existed in any particular past time period. We have no statistical or theoretical basis for knowing whether a phenomena that occurred during the years 2002-2004 will also occur at some point in the future, and if so to what extent it will affect the long-run planning horizon being studied. Similarly, there is no way of knowing whether a phenomena that occurred during the years 2012-2016 subsequently ended in 2017, or whether it continued through the following year, but will end shortly thereafter, and therefore has little or no relevance to the long-run planning horizon.

Dummy variables allow the statistical equation to adapt to specific artifacts of the data that occurred during past years, but they inherently detract from our ability to use the equation to understand or predict what will happen in future years, since we have no way of knowing whether the phenomena that occurred during those years will, or will not, occur in the future, or to what extent those particular phenomena will occur in any particular future year.

Q. You also mentioned data mining. Can you please explain this problem?

A. Yes. Data mining is a term that was coined in the 1990's to describe the process of using computer software to search through a large data sets looking for patterns that are not readily apparent from simply looking at the data. As computers and data storage have become cheaper, it has become practical to assemble extremely large data sets, and companies have found it feasible and convenient to use automated process to search through their data looking for patterns that might provide them with useful insights. A leading provider of Analytics Software explained the benefits this way:

> Retailers, banks, manufacturers, telecommunications providers and insurers, among others, are using data mining to discover relationships among everything from pricing, promotions and demographics to how the economy, risk, competition and social media are affecting their business models, revenues, operations and customer relationships.[26]

In a blog post published by a major statistical software provider, data mining was described this way:

> Data mining uses algorithms to explore correlations in data sets. An automated procedure sorts through large numbers of variables and includes them in the model based on statistical significance alone. No thought is given to whether the variables and the signs and magnitudes of their coefficients make theoretical sense.
>
> We tend to think of data mining in the context of big data, with its huge databases and servers stuffed with information. However, it can also occur on the smaller scale of a research study.[27]

26 SAS, "Data Mining, What it is and why it matters" https://www.sas.com/en_us/insights/analytics/data-mining.html

27 The Mintab Blog, September 21, 2016, "Problems Using Data Mining to Build Regression Models," http://blog.minitab.com/blog/adventures-in-statistics-2/problems-using-data-mining-to-build-regression-models

The author goes on to show how dangerous data mining can be when it is used in developing a regression model.

> My first order of business is to prove to you that data mining can have severe problems.
>
> ...what could possibly be wrong with this approach? Data mining can produce deceptive results. The statistics and graph all look good but these results are based on entirely random data with absolutely no real effects. Our regression model suggests that random data explain other random data even though that's impossible. Everything looks great but we have a lousy model.[28]

Ms. Bartos used a process which closely matches the one this author warns against. She applied data mining to a small data set, experimenting with a large number of different dummy variables before settling on a particular set of dummy variables that happened to give her a particularly good statistical "fit." She then applied this model to the same data set she used to select the variables, rather than testing the resulting equation on an independent data set.

The reason why this process is inappropriate is well explained by the author, so I will quote at length from his article:

> The problem with data mining is that you fit many different models, trying lots of different variables, and you pick your final model based mainly on statistical significance, rather than being guided by theory.
>
> What's wrong with that approach? The problem is that every statistical test you perform has a chance of a false positive. A false positive in this context means that the p-value is statistically significant but there really is no relationship between the variables at the population level. If

28 Ibid.

> you set the significance level at 0.05, you can expect that in 5% of the cases where the null hypothesis is true, you'll have a false positive.
>
> Because of this false positive rate, if you analyze many different models with many different variables you will inevitably find false positives. And if you're guided mainly by statistical significance, you'll leave the false positives in your model. If you keep going with this approach, you'll fill your model with these false positives. That's exactly what happened in our example. ...
>
> As we've seen, data mining problems can be hard to detect. The numeric results and graph all look great. However, these results don't represent true relationships but instead are chance correlations that are bound to occur with enough opportunities. ...
>
> Data mining can have a role in the exploratory stages of an analysis. However, for all variables that you identify through data mining, you should perform a confirmation study using newly collected to data to verify the relationships in the new sample. ...
>
> An alternative to data mining is to use theory as a guide in terms of both the models you fit and the evaluation of your results. Look at what others have done and incorporate those findings when building your model. Before beginning the regression analysis, develop an idea of what the important variables are, along with their expected relationships, coefficient signs, and effect magnitudes.
>
> Building on the results of others makes it easier both to collect the correct data and to specify the best regression model without the need for data mining. The difference is the process by which you fit and evaluate the models. When you're guided by theory, you reduce the number of models you fit and you assess properties beyond just statistical significance.[29]

29 The Mintab Blog, October 19, 2016, "Problems Using Data Mining to Build Regression Models, Part Two," http://blog.minitab.com/blog/adventures-in-statistics-2/problems-using-data-mining-to-build-regression-models-part-two

Q. How serious are these problems?

A. The problems are very significant, but it is not easy to quantify the impact. To provide an order of magnitude indication of the seriousness of the problems, I will focus on a single example – main extensions. The Company's marginal cost estimate for main extensions was developed as follows:

> I prepared a regression analysis to estimate the statistical relationship between the cost of main extensions and design day demand, based on the historical data from 1989 to 2016. The regression results are summarized in Attachment MFB-1, page 4.[30]

Ms. Bartos summarized the result of her statistical analysis in Table 3, included in her direct testimony.[31]

Table 3: Marginal Cost of Distribution Capacity-related Plant Additions

Marginal Plant Additions Component	$ per Dth	Source (Attachment)
Production in lieu of Reinforcement	$56.05	MFB-1 page 1
Reinforcement	$63.33	MFB-1 page 3
Extension	$505.18	MFB-1 page 4
Total	$624.56	

Turning to Attachment MFB-1, page 4, we find the estimated marginal cost of main extensions ($505.18) is extremely dependent on her assumption that the equation for the four year period 2012-2016 is more appropriate to use in the long-run planning horizon. This documentation clearly shows that if one simply assumes the results for 2012-2016 are attributable to unknown unique factors occurring in those particular years,

30 Direct Testimony of Melissa F. Bartos, Page 10.
31 Ibid, Page 11.

and the estimated of costs prior to 2012 are also applicable to years after 2016, the marginal cost estimate changes from $505.18 to $1,672.55.[32]

For the period prior to 2012:
∂ Distribution Plant Additions for Main Extensions / ∂ Design Day Demand = $1,672.54 per Dth

For the period 2012 and beyond:
∂ Distribution Plant Additions for Main Extensions / ∂ Design Day Demand = $505.18 per Dth

No evidentiary support was offered for this assumption, which is not well-grounded in economic theory or practice. Arguably, it is more reasonable to assume the dummy variable captures phenomena that are unique to 2012-2016, in which case it would have no relevance to any other years. Under that assumption, the equation for the 23 year period prior to 2012 would be used for the long-run cost estimate. This has the advantage of focusing on more years of data, and it would better acknowledge that we have no information explaining why those four years had different costs than the other years. Absent convincing evidence that the unique factors applicable to those years will be present to the same degree in future years, there is absolutely no basis for using this dummy variable to estimate marginal costs for a long-run planning horizon.

One more point worth noting: while the most recent change in corporate ownership took place in 2012, I find it hard to believe the new owners suddenly discovered or pointed out a way to slash the cost of main extensions. I find it rather far-fetched to think the new owners found a way to slash reduce cost of main extensions from $1,672.55 per Dth to just $505.18 per Dth on a permanent basis. A far more plausible explanation is that there were unique circumstances applicable to the mains that

32 Ibid, Attachment MFB-1, page 4.

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were installed during those particular years that made it feasible to install them at relatively little cost. The $1,672.55 per Dth estimate appears to be more plausible for use on a going-forward basis.

V. RECOMMENDATIONS

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

A. Reasonable steps can and should be taken in this proceeding to strengthen the incentive for customers to increase the insulation in their home or business and to replace existing, inefficient water heaters and furnaces with more energy efficient ones.

Because of the problems I just explained, the Company's marginal cost estimates should not be relied upon as filed. Instead, the monthly customer charges should be increased, and the tail block rates should be increased more than the initial block rates. By decreasing the fixed part of the bill and increasing the per-therm rates, especially in the tail block, the Commission can reduce the burden on small customers, make the tariff structure more equitable, enable customers to gain greater control over their monthly utility bill, and advance the broad public interest by encouraging energy efficiency.

Q. Have you developed some rate calculations to illustrate your recommendations?

A. Yes. For ease of comparison, I used the same general methodology as the Company. To overcome the Company's grossly excessive estimate of the level of marginal costs, I started with the assumption that customer-related marginal costs were 20% of the level estimated by the Company. This is based, in part, on my assumption that the Company's engineering cost estimates for services, regulators and meters would be applicable to no more than 10 to 15% of all locations in a long-run planning horizon. The costs in other locations are almost entirely fixed or sunk. This estimate also considers the marginal cost of reading the meter and mailing and printing a bill to each customer.

I also assumed the dummy variable for 2012-2016 main extensions is unique to those four years, and therefore the long run marginal cost of main extensions is $1,672.55 per Dth, rather than $505.18. By this assumption I am not implying that other parts of the study were accurately developed. Rather, my intent is simply to provide an order-of-magnitude indication of the potential impact of increasing the usage-related marginal cost estimates to a more realistic level.

Similarly, I used the Company's proposed revenue requirement to prepare these illustrative rates. To be clear, this does not imply any sort of endorsement of the proposed revenue requirement, or specific details of the rate development methodology that I have not discussed. To the contrary, I am anticipating that the revenue requirement determined by the Commission will be lower than the one assumed in these calculation; this will alleviate the larger bill impacts shown in my exhibit.

Q. Can you briefly explain how you developed these illustrative rates?

A. Schedule 1 of my exhibit highlights some key numbers from the revised marginal cost calculations which I used to develop these illustrative rates. Taking these marginal cost estimates into account, but moderating the adjustments to maintain a greater degree of rate continuity, I adjusted the customer charges as shown in the following table.

Customer Class	Current Rate	Marginal Cost	Proposed Rate	Illustrative Rate
R-1 Residential Non-Heat	$15.27	$11.37	$21.50	$11.50
R-3 Residential Heat	$22.10	$11.11	$25.50	$12.75
G-41 C & I Low Load Factor Low Annual	$48.36	$12.44	$55.61	$35.00
G-42 C & I Low Load Factor Medium Annual	$145.08	$23.44	$159.59	$100.00
G-43 C & I Low Load Factor High Annual	$622.61	$39.66	$684.87	$400.00
G-51 C & I High Load Factor Low Annual	$48.36	$12.52	$55.61	$35.00
G-52 C & I High Load Factor Medium Annual	$145.08	$21.67	$159.59	$100.00
G-53 C & I High Load Factor High Annual	$640.74	$68.43	$704.81	$400.00
G-54 C & I High Load Factor High Annual	$640.74	$140.80	$704.81	$400.00

As shown in Schedule 2 of my exhibit, I also eliminated or flattened the existing declining block rate structure. The illustrative rates are linked to the requested revenue requirement for comparison purposes. However, in recommending this flattening of the block rate structure, I am assuming the final revenue requirement will actually be lower, and therefore the rate increase borne by large customers will not be as severe as that shown in my exhibit. To the extent large bill impacts persist after adjusting the rates to match the final revenue requirement, it would be appropriate to phase-in the rate changes, rather than implementing everything in a single year.

Q. Have you looked at how these illustrative rates would impact the newly acquired Keene division?

A. Yes. Customers in the Keene division are currently paying rates that are closer to my illustrative rate design than to the Company's proposed rate design. This is particularly evident with respect to the fixed customer charges, as shown in the following table.

Customer Class	Current Rate	Marginal Cost	Proposed Rate	Illustrative Rate
R-1 Residential Non-Heat	$9.00	$11.37	$21.50	$11.50
R-3 Residential Heat	$9.00	$11.11	$25.50	$12.75
G-41 C & I Low Load Factor Low Annual	$18.00	$12.44	$55.61	$35.00
G-42 C & I Low Load Factor Medium Annual	$18.00	$23.44	$159.59	$100.00
G-51 C & I High Load Factor Low Annual	$18.00	$12.52	$55.61	$35.00
G-52 C & I High Load Factor Medium Annual	$18.00	$21.67	$159.59	$100.00

Q. What are your recommendations concerning the proposed decoupling mechanism?

A. I recommend replacing the existing LRAM with a total revenue decoupling mechanism. If it is feasible to do so, I also recommend using a "real-time" mechanism, which will provide customers with a direct, tangible benefit by smoothing out unexpected weather-related bill fluctuations. While this approach has the disadvantage of adding some administrative costs and complexities, it has the offsetting advantage of improving the timing of cash flows for both customers and stockholders, as discussed earlier in my testimony.

Q. Does this conclude your direct testimony, which was prefiled on November 30, 2017?

A. Yes.

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