STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

Docket No. DG 17-070

Northern Utilities, Inc.

Request for a Change in Rates

TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of the
STATE OF NEW HAMPSHIRE
OFFICE OF THE CONSUMER ADVOCATE

December 20, 2017

Table of Contents

I. INTRODUCTION

Q. 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. 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 proposals submitted by Northern Utilities, Inc. ("Northern Utilities" or "the Company"). More specifically, I will be responding to the direct testimony of Debbie L. Gajewski and Paul M. Normand ("Gajewski and Normand").

My testimony has five major sections, including this introduction. In the second section, I discuss the Company's proposed revenue allocation and rate design, giving particular attention to the proposal to increase the fixed monthly charges paid by 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 discuss 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.

II. THE COMPANY'S RATE DESIGN PROPOSALS

Q. 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) 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 … 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.[1]

The Regulatory Assistance Project also provides a useful perspective concerning the rate design decision-making process:

1 Regulatory Assistance Project, "Smart Rate Design for a Smart Future," July 2015, pg 5.

> 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.[2]

I understand the Commission must weigh the claims made by parties with widely varying perspective; it is for this reason that I will explain my recommendations in considerable detail. Since Northern Utilities' revenue allocation and rate design proposals are closely linked to its marginal cost study, I will also 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. This is the opposite of the approach advocated by the Company. 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 Northern Utilities and to chart a course that makes greater progress toward well-accepted public policy goals, without unduly impacting any group of customers.

2 Ibid, pg. 8.

A. Fixed versus Volumetric Cost Recovery

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

A. The Company's proposals advance its top priority: to increase its customer charges (the fixed monthly rate that applies regardless of how much or how little gas the customer uses).

> Both the marginal and accounting cost studies show that the majority of the costs are fixed and should therefore be recovered through a monthly charge. In fact, only a very small portion of these costs are currently being recovered as fixed monthly charges.[3]

The importance of this reasoning in understanding the Company's rate proposals becomes apparent when studying the workpapers the Company used to develop the proposed rate design, as well as from a careful reading of their testimony.

> We noticed that the present rates have lower customer charges when compared to the costs developed in our two cost studies.[4]

They concluded their top priority was to increase recovery of fixed costs through fixed monthly charges.

> Both cost studies also emphasize a major increase in fixed cost recovery and a corresponding decrease in fixed costs recovery through the volumetric charges.
>
> The most straightforward and simple approach to recover these fixed distribution costs is by applying an increase in the fixed monthly charge.[5]

3 Direct testimony of Gajewski and Normand, pp. 33-34.

4 Ibid, pg. 31.

5 Ibid, pg. 33.

Gajewski and Normand's analysis of fixed costs also led them to conclude that residential rates should be increased more than other rates.

> The majority of these fixed costs are being recovered in the existing volumetric rates and through subsidies from other classes.[6]

> Traditionally, residential customers have shown an extremely lower rate of return when compared to commercial and industrial customers or to the system average rate of return.[7]

However, they did not fully implement their priorities, because they decided to moderate the resulting rate impacts. This constrained the magnitude of the shift in cost recovery from volumetric rates toward fixed monthly charges, as well as the shift in cost recovery from larger users to smaller users.[8]

It is also worth noting that regardless of the explanation, Northern Utilities' primary focus seems to be on increasing the customer charges; the cost study is merely in a supporting role – providing a rationale for that focus. One reason I say that is because the Company is proposing to increase customer charges even when that moves farther away from the results of Gajewski and Normand's marginal cost study.

For example, the existing customer charge for the G-40/T-40 class is $67.45, while the estimated marginal cost is $52.61; instead of reducing this rate to be closer to the marginal cost estimate, the Company proposed to increase it to $77.50.[9] Similarly, the Company's existing customer charge for the G-52/T-52 class is $1,124.19. This

6 Ibid, pg. 34.
7 Ibid, pg. 33.
8 Ibid, pp. 32-33.
9 Schedule DLG/PMN-1G-8, Bates No. 001066.

greatly exceeds the estimated marginal cost of $348.98, but the Company wants to increase the monthly customer charge to $1,290.00. Clearly, if the top priority was simply aligning rates with the estimated costs, the Company would have proposed to decrease this rate to bring it closer to the calculated marginal cost level.[10]

Notwithstanding Gajewski and Normand's focus on the relationship between costs and rates, it is clear the Company's overriding priority is to increase the portion of its revenues received through fixed monthly charges. Otherwise, in those classes where the existing customer charges greatly exceed the calculated costs, the Company would not be proposing increases of nearly 15% – about seven times the recent annual rate of inflation. No cost justification was offered to support this aspect of its rate design proposals, nor was there any acknowledgement that this proposal would exacerbate and perpetuate an existing pattern of overcharging the lowest use customers within these classes.

Q. Succinctly stated, what is your response to these proposals?

A. I disagree with the Company's priorities, its reasoning, its cost analysis, and its proposed rate design. The Commission can best advance the public interest by moving in the opposite direction. While a gradual process may be more appropriate than immediately implementing the reductions in customer charges that could be justified based on some of the evidence I will provide later in my testimony, it would clearly be preferable to at least begin to move in that direction.

10 Ibid.

By decreasing the fixed part of the customer's 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 bills, and a stronger incentive to learn about and adopt more energy efficient products and technologies. Moreover, by moving in the opposite direction to that proposed by Northern Utilities, the Commission can reduce the burden on small customers within each class, thereby making the tariff structure more equitable, it can enable all customers to gain more control over their monthly utility bills, and it can advance the broad public interest by reinforcing efforts that are being made to encourage energy efficiency and reduce our nation's dependence on fossil fuels.

B. Comparison to Other Utilities' Customer Charges

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

A. Northern Utilities' customer charges are significantly 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 Northern Utilities' R-3, R-6, R-10 and R-11 (residential) tariffs all include a customer charge of $21.36, which is nearly double the nationwide median reported by the

American Gas Association. A substantial discrepancy also exists in some of 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 one-third the Company's current customer charge of $67.45 for commercial customers on rates G-40/T-40 and G-50/T-50 (Low Annual use).

As shown in the table below, the data in the American Gas Association report suggest that Northern Utilities' New Hampshire customers may already be paying some of the highest customer charges in the United Sates.

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

Further increasing its already-high customer charges might seem appealing to the Company, since this would further increase the stability of its revenues. However, the current customer charges already impose a large burden on low usage customers compared to the rates charged by many other utilities, and further tilting the balance away from volumetric rates will detract from the widely accepted public policy goal of encouraging energy conservation.

C. Fixed Cost Recovery

Q. The Company implies 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 idea. However, it is just a rhetorical device, or at most at most a pricing tactic – rather than a valid pricing goal. Since it is proposing to increase fixed charges even where this is contrary to its own cost evidence, the Company's actual goal seems to be revenue stability. This goal makes logical sense from a management or stockholder perspective, but it is not a high priority from a public interest perspective. A stable, more predictable revenue stream makes it easier to manage a firm's cash flows, and it might reduce the risks borne by the firm's stockholders to a small degree, but neither of these concerns merit much weight in resolving this issue.

There is no valid public policy rationale for having fixed costs recovered through fixed rates. This does not advance the public interest, and in fact it conflicts with several policy goals, including inter-customer equity and encouragement of energy conservation. Moreover, recovering fixed costs as a uniform dollar amount per customer is not consistent with the way fixed costs are most often recovered in unregulated markets. As I will explain in detail later in my testimony, in competitive markets 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.

In unregulated markets, where substantial fixed, sunk and joint costs exist, these costs are not typically recovered from different products or services through "fixed charges." Instead, 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 fixed dollar amount toward the recovery of joint and common costs merely because the costs are fixed. To the contrary, fixed 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 fixed 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. Northern Utilities' 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.

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 efficient, or 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 fixed 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 percent less per square foot than the smallest store. Similarly, other stores on the street would pay half as much per square foot as the smallest store. Most people will readily concur that this would not be an economically efficient, or 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 the owner of the larger, more costly residence receives more benefit from the government. 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, fixed monthly 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. The rate design I am recommending is more consistent with the cost recovery pattern typically observed when government policy makers decide how best to recover the fixed costs of government. This analogy helps demonstrate the inherent fairness of a non-uniform cost recovery pattern. Taxes provide an example where non-uniform cost recovery is both very familiar and something most people 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, merely because a municipality's budget includes a lot of fixed costs.

I think it is highly significant that policymakers in many different jurisdictions, over the course of many decades, have almost universally concluded it is best to spread the tax burden in ways that ensure that small taxpayers pay 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 non uniform pattern of cost recovery is widely accepted because it spreads the fixed costs of government services more equitably than a "head tax" (where the same amount is paid by each taxpayer). 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. Are economic cost concepts relevant to the rate design and revenue allocation issues in this proceeding?

A. Yes. The Company supports its proposals with an economic cost study, which it characterizes as a "marginal cost" study. It relied on 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 support provided by Northern Utilities for its proposed changes to its existing rate design. While the Company also provided a functional (embedded) cost study, it is only of ancillary importance – supporting conclusions that are primarily justified by reference to the marginal cost study.

Q. Can you explain the difference between marginal and embedded costs?

A. Yes. There are at least three important differences.

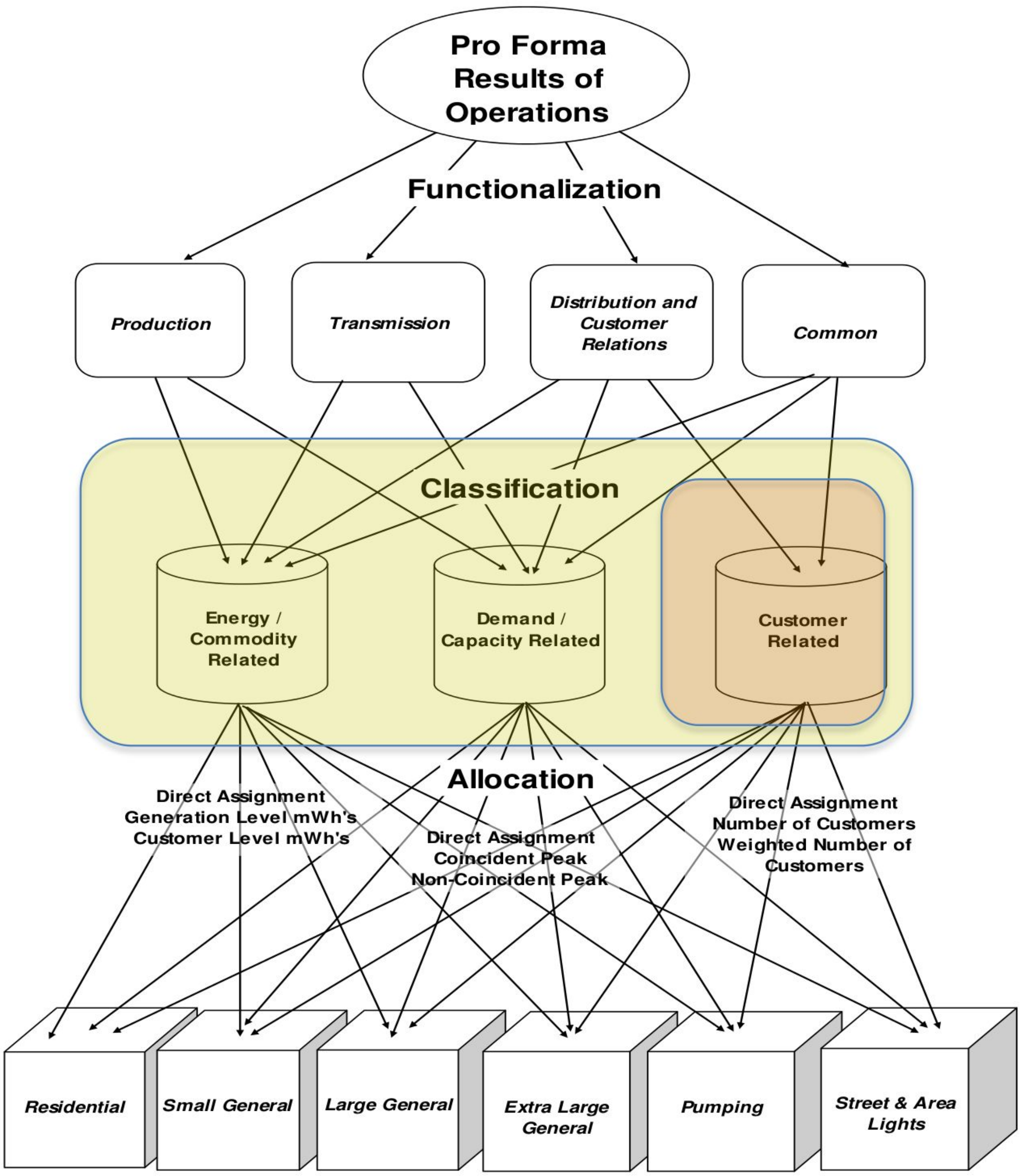
First, and most fundamentally, embedded costs are derived entirely from the accounting records of the firm, and are heavily influenced by and dependent upon the conventions adopted by the firm in maintaining these records. In contrast, marginal costs are a particular type of economic cost. Economic costs 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.

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). 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, and the allocated cost results are also sometimes used to support proposals for specific rate elements.

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 quantitative support for Northern Utilities' 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 Northern Utilities' proposals to increase its customer charges) and the level of “demand costs” (which support its proposals for volumetric rates). Significantly, 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.

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 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 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.

23

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 a planning horizon or "run" that is both internally consistent and appropriate to this context. I will explain these problems in greater detail, after providing the necessary foundation for my 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.[11] 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 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

11 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.

reduce its property insurance or property taxes by disposing of some of its equipment, or 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 that some of its capital investment can be recouped by selling parts of the system to another firm, which 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. This has many important implications, including the fact that economic efficiency is best achieved by ignoring sunk costs, or treating them as zero, regardless of how much has previously been spent on the items in question.

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, starting 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 bringing the fish to market, 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 and bringing them to the market 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 the brief 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

31

incurred by the fisherman are well 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, 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 access 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 Northern Utilities?

A. Yes. Compared to the fishing example, a gas distribution system is much more capital intensive. Hence, it has relatively few costs that can easily be varied in the short run. As a result, we can anticipate that correctly estimated, Northern Utilities' marginal costs will 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. 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 other 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 Northern Utilities' 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 Northern Utilities 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 marginal cost of distributing gas will likely be much higher in the long-run. 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, the cost of Northern Utilities' distribution mains is not entirely fixed or sunk in this longer planning horizon, and will instead be variable (to some degree). 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. Decisions regarding whether or not to replace or upgrade those mains occur "at the margin" and thus the associated costs are neither fixed nor sunk in this planning horizon. Similarly, 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 purely hypothetical "scorched earth" planning horizon, in which every aspect of the firm's capital investment is assumed to be variable.

Most of the pipes and other facilities owned by Northern Utilities 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, which falls 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 percent variable, including those that can only be changed in a completely unrealistic, purely hypothetical, scenario – or one that can only be varied over an extremely long period of time like 100 years.

In the fishing example, in contrast, even the extreme long-run would not require an extremely long time period. It can easily be envisioned by considering a hypothetical example in which a new 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. Similar conclusions would be reached assuming a moderately long time period, which is sufficient to allow the firm to retire or divest all of its existing assets, and to start over in any location of its choice, using whatever mix of capital and labor it chooses. In contrast, for Northern Utilities, an equivalent extreme long-run planning horizon would require an extremely long time period like 100 years or more, or it would require an unrealistic, 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 and a purely hypothetical system is studied – one that 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 percent 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 Northern Utilities' system should be taken as a given, and as a result many of its capital-related costs will appropriately be 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. In the context of this proceeding, I think the most useful analysis falls somewhere between a purely short-run approach and an extreme long-run approach. The approach I am recommending can be thought of as a typical "long-run" which reflects about the same degree of flexibility that actually exists for a gas utility over a 10 to 20 year time period. This is similar to the time frame that is usually envisioned when economists discuss 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. Some, or all, of the existing buildings can be abandoned or sold to someone who will use them for a different purpose; the firm can replace them with a different size factory, or ones in different locations. However, it will normally be assumed that some aspects of its operations 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 more flexible "extreme long-run."

The distinction I am drawing is important because many of the facilities owned by Northern Utilities are buried underground, with a useful economic life of 60 years or more. They can be upgraded or reinforced, but they cannot easily be removed or downsized. That does not mean the costs are entirely fixed. During a 10 to 20 year time frame, some of these facilities will need to be replaced or reinforced. However, many parts of the system have ample spare capacity, and they 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 ignore these distinctions. It would not be logical, or useful, to treat genuinely sunk costs as if they were not sunk, or to treat sunk costs as if they were variable, when they are not. The truth is that some items in the system will not be removed, replaced, upgraded or downsized, no matter what prices are charged – and a correct handling of this issue is critical to developing meaningful marginal cost estimates that are useful in guiding pricing decisions.

That is not to say that purely short-run view of costs should be used, in which nearly all costs are assumed to be fixed or sunk. More useful and meaningful insights can be developed by thinking about the costing problem from the perspective of a 10 to 20 year planning horizon, and recognizing that an array of different situations exist in different parts of Northern Utilities' 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 they are abandoned).

Consumption decisions by customers can potentially accelerate or delay the need for some 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 be analyzed on a more 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 geographic 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 could potentially 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 customers 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. For instance, if brick structures are different from wooden structures, the resulting probability-weighted difference in cost can be considered in developing fire insurance rates – without resorting to a different price for every unique situation.

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 Northern Utilities' 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 (prices exceed marginal costs). 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 prevailing 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 potential differences in the average costs they incur, and 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: under ordinary circumstances, 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 discussing this topic in more detail, can you briefly summarize the solution to the joint cost puzzle?

A. Yes. As it turns out, 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 magnitude of the markup above marginal cost which determines the extent to which joint 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 Northern Utilities 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 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 Northern Utilities 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, Northern Utilities' 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 Northern Utilities 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 of the costs of natural gas delivery 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, in the short run. 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 fairly 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 Northern Utilities' total costs.

Q. Can you explain the joint cost puzzle in more detail?

A. The solution to this puzzle 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 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 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 Northern Utilities' 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 that 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 larger 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 repeatedly mentioned sunk costs. How do they relate to this discussion?

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 in 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 have 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 ensure 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. If the book is a bestseller, prices will generate revenue far in excess of the sunk costs. If it is a flop, prices will fail to recoup 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 unregulated markets determine the price of novels, or beef and hides or Cadillac and Chevrolet automobiles?

A. No. The Commission has considerable flexibility in deciding how to price Northern Utilities' 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 Northern Utilities' 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 is virtually the only evidence offered by Northern Utilities to support its proposed revenue allocation and rate design in this proceeding. The revenue allocation and rate design are both tied to the marginal cost study.[12] The reason for emphasizing marginal costs was explained as follows:

> The use of marginal costs pricing in ratemaking tends to result in prices that best promote economically rational

12 Ibid, pg. 5

> consumption decisions, and thereby promotes an efficient allocation of society's resources. Sending customers accurate price signals regarding the costs that will result from their consumption decisions furthers this efficiency goal. Customers, in turn, will be able to make informed decisions on their use of utility services.[13]

Q. Can you briefly summarize your overall reaction to the Company's marginal cost study?

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. This includes 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 data was analyzed in developing the cost estimates. The combined impact of these theoretical and empirical problems is so severe, it completely invalidates any conclusions that might otherwise be drawn from the study as submitted.

13 Ibid, pg. 27

A. Inconsistencies with economic theory

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

A. No. Gajewski and Normand do not explain their decisions regarding the planning horizon, nor do they explicitly state what "run" they intended to study. However, this passage implies they may have intended to develop a long run cost study:

> A marginal cost study provides an estimate of the cost of providing an additional unit of service in the long run.[14]

I did not find any other mention of the "run" or the "planning horizon" anywhere else in their testimony or exhibit. Yet, 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 cost estimates if a shorter planning horizon is evaluated, and higher cost estimates if a longer planning horizon is studied. In general, 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.

The Company's testimony glosses over these issues, but this brief passage provides a good entry point for explaining them in greater detail:

14 Ibid.

> Marginal costs to serve include two types of cost – costs that vary with the number of customers and costs that vary with the design day demands of customers. In essence, the utility must construct a distribution system capable of handling the anticipated loads of customers under extreme weather conditions. These costs are incurred regardless of the actual weather occurring in the test period and are also independent of the volumes consumed by customers throughout the test year. Therefore, it is more appropriate to recover these costs through a demand charge, or in the absence of demand data, a fixed monthly charge rather than a volumetric charge.[15]

At least four things are noteworthy about this brief passage. First, a distinction is being drawn between costs that vary with the number of customers and costs that vary with peak demand. Second, they consider it noteworthy that both types of costs are “independent of the volumes consumed” during the test year. Third, they argue it is “appropriate” to recover both types of costs through “a fixed monthly charge rather than a volumetric charge.” Thus, they seem to be arguing that the “appropriate” rate design would recover all of the Company's delivery-related costs (excluding the commodity-related costs of the natural gas itself) through “a fixed monthly charge rather than a volumetric charge.” Fourth, although no mention is made of the “run” (which determines the degree to which particular costs are variable), their argument in favor of a fixed monthly charge for recovering costs related to “design day” peak demand implies a moderately short run planning horizon, as does the reference to the “test year” since this is a relatively short period of time.

15 Ibid, pp. 29-30.

Unless the “run” is clearly stated and consistently followed, a mixture of different planning assumptions or time-horizons may be used in different aspects of a marginal or incremental cost study, which leads to serious problems. In that situation, 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 within each portion of the study. This was the situation I encountered when examining the Company's study in this case, and it is the primary reason why I recommend against relying on the study as submitted.

In particular, the Company overlooked or ignored the fact that a service line and meter have already been installed at most buildings that are adjacent to the Company's distribution mains. Hence, the cost of services and meters is fixed or sunk and unavoidable in most situations. In the case of a typical building, which is already connected to the system, if that building sits vacant for a while, the cost will not be reduced just because the service line or meter 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.

Assuming a normal long run planning horizon (not looking at the “extreme long run” and not adopting a purely hypothetical “scorched earth” scenario in which everything is assumed to be variable, including the geographic areas served by the utility), the cost of the service line and meter is likely to be fixed or sunk in most (but not all) cases. This reality was simply ignored by the Company when it developed its cost estimates. It estimated the costs that are incurred when connecting a typical new building to the system, then it assumed these costs would also be applicable to existing buildings. Yet, in reality, those cost of new construction would not be relevant to most existing buildings. In effect, the Company assumed the full cost of the service line and meter would always be "at the margin" but this is a highly unrealistic assumption, which is inconsistent with other aspects of the cost study.

The Company's analysis of the cost of services and meters would only be logical in a "scorched earth" analysis, or an extreme long-run planning horizon. However, it is clear that the rest of the study is intended to reflect a much less extreme version of the long-run. For instance, with respect to distribution mains, historical data was analyzed to estimate the increase in design day demand over time. This data was then compared to increases in the Company's total investment in mains over that same time period. The effect of this exercise was to estimate the portion of the total investment in mains that is varying in response to increases in design day demand over time. The investment in existing mains was effectively excluded. This approach is consistent with the reality that most mains are already in place, and they have a useful life of 60, 70 or more years, and thus the cost of mains is partly fixed or sunk, even in the long-run. Only the portion of the cost of mains that is varying at the margin is being extracted from the historical data, consistent with a traditional long run analysis – and contrary to the approach that was used for services and meters.

66

It is also clear that the Company's study is exclusively focused on how costs change when the number of customers, or design day demand, increases. No attempt was made to examine how much costs decrease when an existing customer leaves the system, or when customers reduce their 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 and meters, while using a very different approach for other items. By examining 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), it is apparent that reductions in usage by one customer can offset increases in usage by another customer, if they are both using the same part of the system. In contrast, some items (for instance, a service line that connects a single customer to the system) are subject to a "ratchet" phenomena.[16] Where this "ratchet" effect applies, the cost is likely to be sunk, rather than fixed.

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

16 The concept of a "ratchet effect" has multiple applications in economics. In general, this terminology is used in situations where (1) something occurs under a particular set of conditions, (2) that occurrence impacts subsequent events and conditions, and (3) the effect of the occurrence cannot easily be reversed. For instance, employers may realize workers will feel insulted by any proposal to reduce their wages, so they will be reluctant to increase wages when business is booming, for fear of losing their trained workforce, if they cannot afford to maintain the higher wages when business returns to normal. Similarly, firms may be reluctant to invest in a larger factory when business is booming, if it would be impossible, to reduce the size of the factory, or shed the associated costs, once business slows down.

validity of the Company's cost estimates and underlying assumptions should be judged in that context. Under the simplest conditions considered in economics, where the 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 there 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 – they should not be ignored or glossed over. A good starting point is to evaluate how much costs change when output is varied by different amounts, or in different directions (increasing or decreasing output), 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? These are important issues which need to be carefully thought through and resolved in a consistent manner, which is appropriate to the specific purpose of the cost analysis.

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 treating everyone the same as a potential customer that is thinking about constructing a new building that is deciding whether or not to use natural gas. This is not the situation confronting most people most of the time, so it obviously deserves less weight than the much more common situation where someone is occupying an existing building, or thinking about moving into an existing building, with an existing connection to Northern Utilities' 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 their 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.

An 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 must 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 fixed or 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

71

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 Northern Utilities 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, Northern Utilities' 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.

Northern Utilities 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. Marginal Cost Estimates

Q. How did the Company estimate the marginal cost of distribution mains?

A. The Company examined historical data related to the installation using several different methods, over several different time periods. In all cases, it appears to have made at least some effort to narrow the focus to the change in total costs associated with a change in output. For instance, it analyzed Distribution Main Extension Investments by dividing the cumulative change in its investment in new main extensions by the cumulative change in Design Day Demand over the same time period. This resulted in a marginal cost estimate of $83.09 per therm over the 25 year period from 1988 through 2012. Commendably, it did not limit itself to this one calculation. For instance, the Company applied the same methodology to the same data set during other, more recent time periods. This resulted in an estimate of $379.44 per therm over the period 2003-2012, and an estimate of $523.94 per therm over the period 2009-2012.

The Company also tried using a different analytical approach with the same data set. For example, it developed a linear regression of the relationship between the cumulative change in Design Day Demand and the cumulative installed footage of main extensions over this same time period, resulting in statistical estimate of the relationship between Design Day Demand and footage. It subsequently took that numerical result (coefficient) and multiplied it times the average cost per foot of main extensions installed during 2009-2012. The result of this multiplication was $132.63, which it called the "Trended Cost Per Design Day Therm."

After considering these (and other) alternatives, it ultimately decided to use the $132.63 estimate as the "Unit Cost for New Main Extensions." It then took this estimate and combined it with a separately developed estimate of the marginal cost of reinforcements and system upgrades attributable to additional load of $85.77. The resulting total estimated marginal cost per "Design Day Therm for Prospective Additions" was $218.40.

No explanation was offered concerning the various judgments that were made in developing these analyses. Nor was an explanation provided concerning the portion of the overall system-wide total cost of mains that was effectively being treated as fixed or sunk. However, the entire process was intended to focus on changes in the Company's total costs associated with increases in design day demand – including the part related to increased demand accommodated by main extensions, and the part related to increased demand along existing routes. This focus on changes in cost at the margin is appropriate, and it is fundamentally different than the approach it used to estimate the cost of services and meters (which I criticized earlier in my testimony).

While distinctions between fixed or sunk costs and variable or marginal costs were not sharply delineated in the Company's work papers, it is clear that a significant portion of the cost of distribution mains is effectively being treated as fixed or sunk, and therefore is not being reflected in the Company's marginal cost estimate per Design Day Therm. In effect, the cost estimates developed by the Company represent a composite of (1) the relatively high costs per Design Day Therm for reinforcing or upgrading distribution mains in locations where load growth creates the need for system reinforcement or additions, (2) the relatively high cost of accommodating increases in Design Day Therms distributed through new Main Extensions, and (3) the relatively low costs of delivering the Design Day Therms through existing distribution mains where ample spare capacity exists, and there is no foreseeable need to upgrade, reinforce, or replace the man. I don't find this approach objectionable in principle, and it is far superior to the approach the Company used to analyze the cost of services and meters (where it simply assumed every service and meter was "at the margin" even though this assumption is clearly not valid). To be clear, however, I am not endorsing the specific calculations.

Q. Do you have any further comments concerning the calculations developed by the Company?

A. Yes. Significantly different marginal cost estimates per Design Day Therm could have been developed using this same basic approach, if slightly different judgments had been made in evaluating the data. To illustrate this point, I developed alternative marginal cost estimates in which I changed a single judgment: the decision to use $132.63 per Design Day Therms (based on the linear regression analysis of cumulative footage multiplied times the 2003-2012 average cost per foot) rather than using $379.44 per Design Day Therm, (based upon the relationship between changes in cumulative investment and changes in cumulative design day therms over the 2003-2012 time period). Both of these calculations were developed and considered by the Company; neither one is self-evidently superior to the other.

Testing the effect of changing this one number, I found that the change flows through the rest of the Company's workpapers, leading to significant changes in the calculated costs – including its derivation of "Marginal Prices Equi-Proportionately Constrained by Embedded Costs."

V. RECOMMENDATIONS

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

A. Northern Utilities' 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.

Accordingly, the fixed monthly customer charges should be decreased, rather than increased as proposed by the Company. Similarly, the residential 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.

Finally, because of the inconsistencies and problems discussed in my testimony, I recommend that the Company's marginal cost estimates not be relied upon as filed. If the study is going to be used, it should first be modified, at a minimum, to recognize that the cost of services and meters is fixed or sunk in most locations.

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

A. Yes. For ease of comparison, I used the same general methodology as the Company. In an effort to overcome the problems with the Company's marginal cost study, I made the conservative 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 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. I also tested the impact of using the $379.44 estimate for the "Unit Cost for New Main Extensions" as described above. By testing the impact of this modification, I am not endorsing this specific estimate, nor am I implying that all other parts of the study were accurately developed. Rather, my intent is simply to provide an order-of-magnitude indication of the impact of using more realistic and internally consistent marginal cost estimates for the remainder of the rate design analysis.

The following table highlights some key numbers from my revised marginal cost calculations. The first column of data shows the marginal customer cost estimates adjusted for fixed and sunk costs. The second column shows the effect of scaling up the marginal cost estimates on an equi-proportional basis to match embedded costs, using the Company's methodology and cost estimates. Finally, the third column shows the effect of using the same process with just one change: substituting the $379.44 estimate for the "Unit Cost for New Main Extensions" as described above.

79

Marginal Customer Cost Estimates			
Customer Class	**Marginal Cost**	**Equi-Proportional Scaling A**	**Equi-Proportional Scaling B**
R-6, R-11 Residential Non-Heat	**$8.62**	**$17.73**	**$10.11**
R-5, R-10 Residential Heat	**$9.00**	**$18.51**	**$10.55**
G-40 C & I Low Annual High Winter	**$10.74**	**$22.09**	**$12.59**
G-50 C & I Low Annual Low Winter	**$10.56**	**$21.73**	**$12.39**
G-41 C & I Medium Annual High Winter	**$25.42**	**$52.30**	**$29.82**
G-51 C & I Medium Annual Low Winter	**$23.64**	**$48.64**	**$27.73**
G-42 C & I High Annual High Winter	**$59.86**	**$123.67**	**$70.20**
G-52 C & I High Annual Low Winter	**$49.42**	**$101.66**	**$57.96**

The first column of data in the following table shows my recommended customer charges. For comparison, the second column of data shows the marginal cost estimates, scaled to match embedded costs on an equi-proportional basis using the $379.44 estimate for the "Unit Cost for New Main Extensions." The third column of data shows the current rate.

Customer Class	**Recommended Customer Charges**	**Scaled Marginal Cost**	**Current Rate**
R-6, R-11 Residential Non-Heat	$15.00	**$10.11**	$21.36
R-5, R-10 Residential Heat	$15.00	**$10.55**	$21.36
G-40 C & I Low Annual High Winter	$45.00	**$12.59**	$67.45
G-50 C & I Low Annual Low Winter	$45.00	**$12.39**	$67.45
G-41 C & I Medium Annual High Winter	$125.00	**$29.82**	$196.73

Customer Class	Recommended Customer Charges	Scaled Marginal Cost	Current Rate
G-51 C & I Medium Annual Low Winter	$125.00	**$27.73**	$196.73
G-42 C & I High Annual High Winter	$725.00	**$70.20**	$1,124.19
G-52 C & I High Annual Low Winter	$725.00	**$57.96**	$1,124.19

To further illustrate the impact of these recommended customer charges, I developed illustrative volumetric rates using the Company's proposed revenue requirement and revenue allocation process, as shown below:

Illustrative Rates			
Customer Class	**Customer Charge**	**Winter**	**Summer**
R-6, R-11 Residential Non-Heat	$15.00	$1.1932	$1.1932
R-5, R-10 Residential Heat **1-50 Therms**	$15.00	$0.8122	$0.7200
R-5, R-10 Residential Heat **Excess Therms**	$15.00	$0.7386	$0.7200
G-40 C & I Low Annual High Winter	$45.00	$0.3978	$0.3978
G-50 C & I Low Annual Low Winter	$45.00	$0.3978	$0.3978
G-41 C & I Medium Annual High Winter	$125.00	$0.3138	$0.2662
G-51 C & I Medium Annual Low Winter	$125.00	$0.2091	$0.1946
G-42 C & I High Annual High Winter	$725.00	$0.2503	$0.1805
G-52 C & I High Annual Low Winter	$725.00	$0.1848	$0.1014

These illustrative rates do not imply any sort of endorsement of the proposed revenue requirement, or details of the approach used in the Company's rate development workpapers that I have not discussed here. To the contrary, I anticipate the Commission will reduce the revenue requirement, and this is reflected in the customer charges I am recommending.

Needless to say, a lower revenue requirement will alleviate the bill impacts that would result from these illustrative volumetric rates. To be clear, while I recommend flattening the declining block residential rate structure, the extent to which this recommendation can reasonably be implemented will depend in part on the final revenue requirement adopted by the Commission. If the final revenue requirement results in unacceptably large bill impacts, it would be appropriate to phase-in my recommended rate design changes, rather than implementing everything in a single year.

Q. Does this conclude your direct testimony, which was prefiled on December 20, 2017?

A. Yes.