STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

Docket No. DG 20-105

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

Petition for Permanent Rate Increase

TESTIMONY

OF JEROME D. MIERZWA

On Behalf of the

OFFICE OF THE CONSUMER ADVOCATE

March 18, 2021

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal at and President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Canisius College in Buffalo, New York in 1981 with a Bachelor of Science Degree in Marketing. In 1985, I received a Master's Degree in Business Administration with a concentration in finance, also from Canisius College. In July 1986, I joined National Fuel Gas Distribution Corporation ("NFGD") as a Management Trainee in the Research and Statistical Services ("RSS") Department. I was promoted to Supervisor RSS in January 1987. While employed with NFGD, I conducted various financial and statistical analyses related to the company's market research activity and state regulatory affairs. In April 1987, as part of a corporate reorganization, I was transferred to National Fuel Gas Supply Corporation's ("NFG Supply's") rate department where my responsibilities included utility cost-of-service and rate design analysis, expense and revenue requirement forecasting, and activities related to federal regulation. I was also responsible for preparing NFG Supply's Federal Energy Regulatory Commission ("FERC") Purchased Gas Adjustment ("PGA") filings and developing interstate pipeline and spot market supply gas price projections. These forecasts were utilized for internal planning purposes as well as in NFGD's 1307(f) proceedings.

In April 1990, I accepted a position as a Utility Analyst with Exeter. In December 1992, I was promoted to Senior Regulatory Analyst. Effective April 1996, I became a Principal of Exeter. Since joining Exeter, I have specialized in evaluating the gas purchasing practices and policies of natural gas utilities, utility class cost-of-service and rate design analyses, sales and rate forecasting, performance-based incentive regulation, revenue requirement analysis, the unbundling of utility services, and evaluation of customer choice natural gas transportation programs.

Q. **HAVE YOU PREVIOUSLY TESTIFIED ON UTILITY RATES IN REGULATORY PROCEEDINGS?**

A. Yes. I have provided testimony on more than 350 occasions in proceedings before the FERC and utility regulatory commissions in Arkansas, Delaware, Georgia, Illinois, Indiana, Louisiana, Maine, Massachusetts, Montana, Nevada, New Jersey, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas, Utah, and Virginia.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. On July 31, 2020, Liberty Utilities ("Energy North Natural Gas") Corporation d/b/a Liberty Utilities ("EnergyNorth" or the "Company") filed with the New Hampshire Public Utility Commission ("Commission") a Petition for Permanent and Temporary Rates ("Petition"). Exeter was retained by the New Hampshire Office of Consumer Advocate ("OCA") to review the cost-of-service studies and rate design proposals included in EnergyNorth's Petition. My testimony addresses the Company's functional and marginal cost-of-service studies and rate design proposals included in the Petition.

Q. **PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

A. With respect to the Company's functional cost of service study, the purpose of that study is to determine which portion of the Company's revenue requirement should be recovered through base distribution rates and which portion should be recovered through the Cost of Gas ("COG") mechanism. The Company's functional cost of service study appears reasonable for this limited purpose.

With respect to the Company's marginal cost of service study ("MCOSS"), the purpose of which is to establish the base distribution cost of serving each customer rate class served by EnergyNorth, I have reached the following conclusions:

- The Company's MCOSS misallocates distribution mains plant investment and related costs and produces results that do not reasonably reveal an accurate indication of class-allocated cost responsibilities and should be rejected.
- EnergyNorth's proposed revenue distribution, based on its MCOSS, is not reasonably allocated among its customer rate classes.
- Because the MCOSS presented by EnergyNorth in this proceeding is unreasonable, any increase or decrease in rates which the Commission determines is warranted in this proceeding should be distributed by adjusting the revenues to be recovered from each rate class by the system average increase or decrease.
- If the Commission determines that an increase in rates is warranted in this proceeding, for Residential customers, that increase should be implemented through adjustments to delivery charges. If the Commission determines that a decrease in rates is warranted in this proceeding, for Residential customers, that decrease should be implemented through adjustments to monthly customer charges.

Q. **HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

A. Including this introductory section, my testimony is divided into five sections. In the following section, I address the Company's functional cost-of-service study. The third section of my testimony details reasons that support a finding that EnergyNorth's MCOSS produces an inaccurate indication of the allocated costs of serving the Company's various customer rate classes. The fourth section addresses class revenue requirement allocations. The final section of my testimony addresses EnergyNorth's proposed Residential rate design.

II. FUNCTIONAL COST-OF-SERVICE STUDY

Q. **BRIEFLY DESCRIBE THE FUNCTIONAL COST-OF-SERVICE STUDY SUBMITTED BY LIBERTY IN THIS PROCEEDING.**

A. The Company's functional cost-of-service study is sponsored by Kenneth A. Sosnick of FTI Consulting, Inc. The functional cost-of-service study separates EnergyNorth's revenue requirements into four functions: delivery (distribution service), direct gas costs, Liquified Petroleum Gas ("LPG"), and Liquified Natural Gas ("LNG") costs, and miscellaneous indirect costs. The direct costs of purchasing gas including LPG and LNG as well as related indirect costs (collectively referred to as "production costs"), are recovered through the Company's COG mechanism rather than base distribution rates. The costs associated with delivering gas to customers are recovered through base distribution rates. The purpose of EnergyNorth's functional cost-of-service study is to determine which costs should be recovered through the COG mechanism and which costs should be recovered through base distribution rates to ensure there is neither duplication of cost recovery nor stranded costs that are not recovered through either the COG mechanism or base distribution rates.

Q. **DID YOUR REVIEW FIND ENERGYNORTH'S FUNCTIONAL COST-OF-SERVICE TO BE REASONABLE?**

A. Yes. The Company's functional costs-of-service study appears reasonable for the limited purpose of determining the costs that should be recovered through the COG mechanism.

III. MARGINAL COST-OF-SERVICE STUDY

Q. **WHAT IS THE PURPOSE OF THE COMPANY'S MCOSS?**

A. While the purpose of the Company's functional cost-of-service study is to determine the portion of the Company's revenue requirement that should be recovered through the COG mechanism and the portion to be recovered through base distribution rates, the purpose of the MCOSS is to assist a utility or commission in determining the level of base rate distribution revenues properly recoverable from each of the various rate classes to which EnergyNorth provides utility distribution service. Under a MCOSS, the allocation of recoverable costs to each class of service should generally be based on cost causation principles.

Q. **PLEASE IDENTIFY THE CUSTOMER RATE CLASSES INCLUDED IN THE COMPANY'S MCOSS.**

A. The Company's tariff indicates that natural gas distribution service is available under approximately 40 different rate schedules. The Company's MCOSS consolidates these 40 rate schedules into 20 rate classes. For purposes of determining the rate increase to be assigned to each rate class, the Company has consolidated these 20 rate classes into 10 rate classes as follows:

- R-1 & R-5 – Residential Non-Heating
- R-3 & R-6 – Residential Heating
- R-4 & R-7 – Low Income Residential Heat
- G-41 & G-44 – C&I Low Annual, High Winter
- G-42 & G-45 – C&I Medium Annual, High Winter

- G-43 & G-46 – C&I High Annual, High Winter
- G-51 – G-55 – C&I Low Annual, Low Winter
- G-52 – C&I Medium Annual, Low Winter
- G-53 – C&I High Annual, Load Factor <90%
- G-54 & G-59 – C&I High Annual, Load Factor >90%

Q. **PLEASE DESCRIBE HOW ENERGYNORTH PERFORMED ITS MCOSS.**

A. The Company's MCOSS is presented by Matthew J. DeCourcey of FTI Consulting, Inc. Mr. DeCourcey describes the MCOSS he presents as follows:

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

Q. **PLEASE DESCRIBE THE VARIOUS COSTS INCLUDED IN THE COMPANY'S MCOSS AND HOW THE MARGINAL COSTS WERE**

DETERMINED FOR THE PURPOSES OF ALLOCATING COSTS TO THE VARIOUS CUSTOMER RATE CLASSES.

A. The major cost items included in the Company's MCOSS and the basis for determining the assignment of marginal costs are identified as follows:

Cost Item	Assignment
Capacity-Related Distribution Plant Costs for Reinforcements	Design Day Demand
Capacity-Related Distribution Plant Costs for Mains Extensions	Design Day Demand
Capacity-Related Distribution O&M Expense	Design Day Demand
Capacity-Related Distribution Production Expense	Design Day Demand
Customer-Related O&M Expense	Annual Customers
Customer-Related Accounting & Marketing Expense	Annual Customers

As indicated previously, the Company generally determined marginal costs as related to either design day demand or the annual number of customers served.

Q. **IS IT REASONABLE TO DETERMINE MARGINAL CAPACITY-RELATED DISTRIBUTION PLANT COSTS OR O&M EXPENSES SOLELY BASED ON DESIGN DAY DEMANDS AS ENERGYNORTH HAS DONE IN ITS MCOSS?**

A. No. The design day demand utilized in EnergyNorth's MCOSS was based on a day with a 1-in-30-year probability of occurrence. If an allocation of capacity-related distribution plant costs or O&M expenses (i.e., distribution mains costs) on the basis of design peak day demands was in accordance with the principle of cost causality,[1] then the demand for natural gas under design day weather conditions would have to be the only cause for the existence of and customer utilization of EnergyNorth's distribution system. Design day demands represent the maximum demands that are

[1] The principle of cost causality requires costs to be allocated to customers on the basis of the customers' relative use of the service units that gave rise to the costs in the first place.

expected under the most severe weather assumptions used for planning purposes. While a portion of EnergyNorth's distribution mains costs are associated with, and should be allocated on, design peak demands, it is obviously wrong to profess that most distribution mains costs are caused by consumer demands on the coldest day experienced in EnergyNorth's service territory every 30 years or so. Quite simply, if EnergyNorth's customers had a demand for gas only on days that occur every 30 years, there would not be a EnergyNorth gas distribution system. The costs of delivered gas supplies on that one design peak day would be prohibitively high, and the cost of delivering gas through EnergyNorth's distribution system on that one day simply could not compete with alternative energy costs. For example, EnergyNorth's claimed annual cost of providing service is approximately $100 million, and its projected design day demands are 176,360 Dth. This implies a cost of approximately $570 per Dth to meet design day demands. If a design day occurred only once every 30 years, this would imply a cost of $17,000 per Dth to meet demands on that single day.

Q. **IF NATURAL GAS DISTRIBUTION COMPANY ("NGDC") SYSTEMS ARE NOT BUILT SOLELY TO MEET THE COLDEST DAY THAT MAY BE EXPERIENCED EVERY 30 YEARS, WHY DO NGDCs INCUR DISTRIBUTION CAPACITY-RELATED COSTS?**

A. The basic reason why NGDCs like EnergyNorth invest in their distribution systems is to meet the annual demands for gas by end-use customers. This is the reason for the existence of the NGDC in the first place. Without sufficient annual gas usage by which to amortize the annual costs of providing service, there would be no gas distribution system. Additionally, as I will describe later, a portion of the total cost of distribution service is related to installing a system with enough throughput capacity to meet design day demands in excess of annual demands. Because distribution mains exist and are related to both annual demands and peak demands, both annual and peak demands must be recognized in the allocation of distribution mains costs if the allocation is to be in accordance with the principle of cost causality.

Q. **DOES ENERGYNORTH'S MAINS EXTENSION POLICY CONSIDER DESIGN PEAK DEMANDS IN THE COMPANY'S INVESTMENT DECISION-MAKING PROCESS?**

A. No. First Revised Page 9, Section 7(B)(3) of the Company's tariff sets forth the Company's main and service extension policy. Residential main and service extensions will be installed at no charge to the customer provided that the Estimated Net Margins (customer and delivery charge revenues) is at least one-eighth of the estimated cost of construction of the main and service extensions. If the Estimated Net Margin is less than one-eighth, the customer is required to pay the difference. For Commercial and Industrial customers, the Estimate Net Margin is at least one-sixth of the estimated cost of construction. The Company's base rate revenues are primarily collected on the basis of throughput. Therefore, sufficient annual throughput volumes are the primary consideration in the Company's decision to serve new customers and its capacity-related distribution investment decision-making process.

Q. **WHY IS IT PROPER TO ALLOCATE DISTRIBUTION MAINS INVESTMENT ON THE BASIS OF ANNUAL, AS WELL AS PEAK, DEMANDS?**

A. The allocation of mains investment costs on the basis of both annual and peak demands is in accordance with the principle of allocating costs on the basis of cost causality. Natural gas is of little to no value to the customer if that gas cannot be delivered to the location of the gas-burning equipment. EnergyNorth's distribution system imparts locational value to the natural gas delivered across that system by allowing for the movement of that gas from its acquisition source to each customer's location. EnergyNorth's distribution system exists, and related costs are incurred, to deliver gas to its customers whenever, over the course of each year, its customers demand gas. In other words, EnergyNorth's system was built, and costs were incurred to deliver gas; both at the time of peak system demand and generally throughout the year. Because costs are incurred to deliver gas generally throughout the year, and additional costs are incurred to meet peak demands, EnergyNorth's distribution mains costs must be allocated on the basis of both annual and peak demands if those costs are to be allocated in accordance with the principle of cost causality.

Q. **PLEASE EXPLAIN YOUR STATEMENT THAT COSTS ARE INCURRED TO DELIVER BOTH ANNUAL AND PEAK VOLUMES ACROSS ENERGYNORTH'S SYSTEM.**

A. The customers included in the Company's MCOSS are projected to move approximately 17.8 million Dth across EnergyNorth's system during a year. This equates to an average demand of about 48,800 Dth per day. EnergyNorth's design day demand is about 176,360 Dth. EnergyNorth cannot meet its customers' annual gas demands with a system capability any smaller than 48,800 Dth per day. In other words, if there were no variance in the daily demands on EnergyNorth's system, the capacity of that system would have to be designed to accommodate the daily movement of 48,800 Dth per day just to meet the annual demands. To meet peak demands, EnergyNorth's system capacity must be about 3.5 times greater than 48,800 Dth. Thus, some costs are related to the average deliveries each day on the EnergyNorth system, and some costs are related to the movement of gas when demands are above the average demand.

Rational investment decision analysis requires the consideration of annual volumes delivered across an NGDC's system. A gas distribution system would not exist if all demand-related costs were the responsibility of design peak demands. Customers would simply choose other energy alternatives. A viable gas market is dependent upon the ability to amortize delivery costs over a sufficient volume of service so as to result in a unit cost that can be recovered at a price at which gas can be sold and still compete with other energy sources. The association of costs with annual, as well as peak, demands, and the allocation of costs on the basis of both annual and peak demands for gas, are absolutely essential to the economic feasibility of a gas delivery system. To largely ignore annual demands and allocate total mains costs on peak demands would be inconsistent with the consideration of annual demands, which are absolutely essential to the economic justification of the very costs being allocated.

Q. HOW DO THE COSTS OF PROVIDING FOR THE MOVEMENT OF GAS TO MEET DESIGN DAY PEAK DEMANDS COMPARE TO THE COSTS OF PROVIDING FOR THE MOVEMENT OF GAS TO MEET LESSER DEMANDS?

A. Many of the costs associated with the distribution delivery system do not depend upon pipe sizes. These costs would include planning, surveying, excavation, hauling, pipe bed preparation, unloading and stringing of pipe, municipal inspection, backfill, and pavement and sidewalk replacement. Since a portion of total costs does not vary with pipe size, or are fixed costs, total costs do not increase at a 1-to-1 ratio with increases in maximum demands. The additional costs associated with meeting elevated demands are largely related to the cost of the pipe itself.

Moreover, throughput capability increases not at a 1-to-1 ratio with the size of the pipe, but at a rate equal to the square of pipe diameter. Doubling the diameter of a pipe, for example, increases its capacity by four times the original capacity. Thus, the marginal costs of providing additional capacity are lower than the average costs of providing capacity. This means that the costs associated with providing capacity for the movement of average demands are greater on a unit basis than the costs associated with providing capacity for additional demands. EnergyNorth's distribution system exists to deliver annual system requirements. There are costs that are uniquely associated with meeting peak demands, and as such, peak demands should bear some cost responsibility.

Q. **ARE GAS FLOWS DURING THE DESIGN PEAK SO IMPORTANT THAT MOST OF ENERGYNORTH'S TOTAL CAPACITY-RELATED DISTRIBUTION SYSTEM COSTS ARE DIRECTLY RELATED TO, AND CAUSED BY, PEAK DAY DEMAND REQUIREMENTS?**

A. No. Peak demands are not the major cause of EnergyNorth's demand-related mains cost, and it would be wrong to allocate distribution mains-related costs largely on the basis of peak demands. Only the marginal costs incurred to meet peak demands above other demands are caused by, or directly related to, peak requirements. EnergyNorth's gas delivery system simply would not be viable and would not exist if the only demand for gas was the demand associated with extreme weather conditions. EnergyNorth's delivery system exists because the total annual demand for gas is sufficient to warrant its existence. Because EnergyNorth's system exists to deliver annual gas requirements, but some additional costs are related to the delivery of gas during periods of elevated demand, it is appropriate to allocate the Company's distribution mains costs on both annual and peak demands. The allocation of capacity-related distribution system-related costs only on the basis of peak demands misallocates substantial costs.

Q. **TO WHAT EXTENT DO THE COSTS OF MEETING PEAK GAS FLOW REQUIREMENTS EXCEED THE COSTS OF MEETING AVERAGE GAS FLOW REQUIREMENTS?**

A. As noted, EnergyNorth's design peak day peak demand is about 3.5 times its average demand. A pipe's cross-sectional area, and correspondingly its capacity, varies with the square of its radius. Therefore, doubling the size of a pipe's radius (or diameter) increases the capacity of the pipe fourfold. For example, doubling the diameter of a 3-inch pipe to six inches increases the capacity by four times the capacity of the 3-inch pipe. Increasing the diameter of a 3-inch pipe to twelve inches increases the capacity by 16 times. The costs of meeting increased flow requirements that are caused by, or associated with, elevated demands are answered by the relationship of the change in total capacity costs to the change in capacity.

I explained earlier that since many distribution delivery system costs do not vary with pipe size, the increased costs associated with meeting increased capacity requirements are expected to be small. Indeed, it is largely these economies of scale that lead to falling average costs of service and the provision of gas distribution service more economically by one monopoly provider, like EnergyNorth, rather than by many competing providers.

Q. **DO YOU HAVE ENERGYNORTH-SPECIFIC DATA IDENTIFYING THE COSTS ASSOCIATED WITH MEETING INCREASED CAPACITY REQUIREMENTS?**

A. Yes. Table 1 reflects for those pipe sizes with a total investment in excess of $35 million the average installed cost per foot based on the response to OCA 1-28.

Table 1.
EnergyNorth Cost of Installed Distribution Mains

Diameter (inches)	**Average Cost** (per foot)
2	$22.54
4	34.25
6	50.90
8	73.47
12	117.84

As shown on Table 1, the average cost of installing a 2-inch main was approximately $23 per foot, while the average cost of installing a 4-inch main was approximately $34 per foot. Thus, for a fourfold increase in capacity, EnergyNorth's total average costs increased by nearly 50 percent (($34 - $23) / $23). Based on this example, a doubling of the pipe size (and hence a quadrupling of capacity) increased capacity costs by nearly 50 percent, indicating that increased demands above average demands can be accommodated at increased distribution mains costs that are approximately 13 percent (50 percent / fourfold increase in capacity) of the costs of meeting average demands:

2-inch	4-inch	Cost per Foot Increase	Percent	Capacity Increase	Cost of Peak
(a)	(b)	(c) = (b)-(a)	(d) ~ (c)/(a)	(e)	(f) = (d)/(e)
$23.00	$34.00	$11.00	50%	4	13%

Table 1 also indicates that the average cost of installing an 8-inch main was approximately $75 per foot. Thus, for a 16-fold increase in capacity, EnergyNorth's total average costs increased by more than 225 percent (($75 - $23) / $23) over the cost of a 2-inch pipe. Based on this example, a quadrupling of pipe size (and hence a 16-fold increase in capacity) increased capacity costs by about 225 percent, indicating that increased demands above average demands can be accommodated at an increased distribution mains costs that are 14 percent (225 percent / 16-fold increase in capacity) of the costs of meeting average demands:

2-inch	8-inch	Cost per Foot Increase	Percent	Capacity Increase	Cost of Peak
(a)	(b)	(c) = (b)-(a)	(d) ~ (c)/(a)	(e)	(f) = (d)/(e)
$23.00	$75.00	$52.00	225%	16	14%

Given these two EnergyNorth-specific examples above, less than half of distribution main costs are associated with meeting elevated peak demand requirements and could be allocated based on peak demands, and the remainder is related to customers' annual demands for natural gas and could be allocated on average demands.

Q. **HOW CAN DISTRIBUTION MAINS INVESTMENT COSTS BE PROPERLY ALLOCATED?**

A. The additional costs of providing capacity in order to meet peak demands, as opposed to lesser demands, should be allocated on a peak demand basis. As I just demonstrated, less than half of EnergyNorth's distribution mains costs are associated with meeting increased demands; hence, a portion of mains costs should be allocated on the basis of peak demands. I believe it would be reasonable to allocate 50 percent of EnergyNorth's distribution mains system costs, instead of a lesser amount, based on design peak demands. I believe it would be reasonable to allocate the remaining 50 percent of EnergyNorth's distribution mains costs, being related to, or caused by, EnergyNorth's annual gas requirements, based on annual, or average, demands. This recommended 50 percent peak demand and 50 percent annual demand allocation of distribution mains costs is commonly referred to in the industry as the Peak & Average Method.

Q. **HAVE OTHER COMMISSIONS ACCEPTED THE USE OF THE PEAK & AVERAGE METHOD?**

A. Yes. The Pennsylvania Public Utility Commission ("PaPuc") has accepted the fact that distribution mains are built on the basis of year-round demands as well as peak demands. In the 1994 base rate proceeding of National Fuel Gas Distribution, the Commission accepted the Peak & Average methodology, stating, "The Peak & Average method that allocates mains equally is a sound and reasonable method of cost allocation and should remain intact." *Pa. P.U.C. v. National Fuel Gas Distribution Co.*, 83 Pa. PUC 262, 360 (1994); *see also Pa. P.U.C. v. National Fuel Gas Distribution Co.*, 73 Pa. PUC 552 (1990); *Pa. P.U.C. v. Equitable Gas Co.*, 73 Pa. PUC 301 (1990); and *Pa. P.U.C. v. EnergyNorth Gas Co.*, 69 Pa. PUC 138 (1989). In a very recent Columbia Gas of Pennsylvania proceeding, the PaPuc reaffirmed its support of the Peak & Average Method (Docket No. R-2020-3018835, Opinion and Order entered February 19, 2021).

The Indiana Utility Regulatory Commission ("IURC") has strongly endorsed the use of the Peak & Average methodology. See *In re Citizens Gas & Coke Utility*, IURC Cause No. 42767 (Oct. 19, 2006). The IURC found that the Peak & Average method was the "equitable and realistic" method for allocating distribution mains costs, and provided the following analysis:

> Based upon the record evidence, this Commission concludes that the OUCC's cost-of-service study is most reflective of cost causation and possesses a high degree of objectivity upon which the Commission may place reliance in establishing the rates and charges in this proceeding.
>
> While we do not doubt that distribution mains must be constructed with peak demand in mind, distribution mains do not only serve customers on peak demand days. Therefore, a measure of the costs of distribution mains must be allocated to customers based on their usage that takes place on non-peak days. For example, a customer that does not take service at all on the peak demand day-and therefore contributes nothing to peak demand requirements of distribution mains-but receives service through distribution mains at other times should be responsible for some portion of distribution main costs.
>
> The OUCC's approach is much more equitable and realistic. Rather than allocating distribution main costs exclusively based on either peak demand day or average annual consumption, the OUCC used a compromise approach that allocated these costs based on both. Under the OUCC's cost-of-service study, 80% of distribution main costs are allocated based on average demand. (Public's Ex. No. 6 at 13.) In this way, the OUCC's approach allocates part of distribution main costs to customers who

> receive service through distribution mains throughout the year but who may not receive much or any service on the peak demand day.
>
> For the reasons set forth above, we find the OUCC's cost-of-service study most accurately reflects the manner in which distribution main costs are actually incurred. See, In Re Citizens Gas & Coke Utility, IURC Cause No. 39066, at 31 (Nov. 1, 1999). We therefore adopt the OUCC's cost-of-service study to implement the rates increase approved in this Cause.

In re Citizens Gas & Coke Utility, IURC Cause No. 42767, at 74-75 (2006).

The Illinois Commerce Commission ("ICC") has accepted the Peak & Average method for allocating transmission and distribution costs in the natural gas industry. The ICC explained the reasoning behind utilizing a Peak & Average methodology in their decision as follows:

> Generally, [Central Illinois Public Service Company or CIPS] and [Union Electric Company or UE] gas transmission and distribution facilities exist because there is a daily need for such facilities. Regardless of when CIPS and UE experience their respective peak and the level of the peak, customers depend on the continued operation of the Ameren gas transmission and distribution systems to meet their daily needs. On the day that the peak does occur. Ameren's own Mr. Carls testifies that CIPS' and UE's respective systems are built to accommodate the system peak without regard to each class' peak. In light of the nature in which the transmission and distribution systems are used and because of the relatively declining cost of increasing capacity, peak demand is not the appropriate emphasis in allocating demand costs…As the Commission concluded in Docket 94-0040, a utility can not justify its transmission and distribution investment

> on demands for a single day. The allocation method that properly weights peak demand is the [Average & Peak or A&P] method, the same method that the Commission adopted in CIPS' and UE's last gas rate cases. The A&P method properly emphasizes the average component to reflect the role of year-round demands in shaping transmission and distribution investments.

Central Ill. Pub. Service Co. Proposed General Increase in Natural Gas Rates, et al., 2003 Ill. PUC Lexis 824, 231-232 (2003).

Q. **SHOULD THE RESULTS OF THE COMPANY'S MCOSS BE UTILIZED TO DETERMINE THE DISTRIBUTION OF A REVENUE INCREASE OR DECREASE WHICH THE COMMISSION DETERMINES IS WARRANTED IN THIS PROCEEDING TO THE VARIOUS RATE CLASSES SERVED BY ENERGYNORTH?**

A. No. As just explained, EnergyNorth's MCOSS fails to provide any recognition to the importance of annual volumes in the Company investment decision process and therefore, does not reasonably reflect an accurate indication of class-allocated cost responsibilities. As such, the results of the Company's MCOSS should not be utilized to determine the distribution of a revenue increase or decrease which the Commission determines is warranted in this proceeding. My recommendations concerning the distribution of a revenue increase or decrease in this proceeding is discussed in the following section of my testimony.

IV. CLASS REVENUE REQUIREMENTS

Q. **PLEASE DESCRIBE HOW ENERGYNORTH IS PROPOSING TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE AMONG ITS CUSTOMER CLASSES IN THIS PROCEEDING.**

A. The Company's proposal to distribute its requested revenue increase is described on pages 26 through page 40 of Mr. DeCourcey's testimony.

Q. **WHAT ARE SOME OF THE PRINCIPLES OF A SOUND REVENUE ALLOCATION?**

A. A sound revenue allocation should:

- Utilize class cost-of-service study results as a guide;
- Provide stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously averse to ratepayers or the utility (gradualism);
- Yield the total revenue requirement;
- Provide for simplicity, certainty, convenience of payment, understandability, public acceptability, and feasibility of application; and
- Reflect fairness in the apportionment of the total cost of service among the various customer classes.[2]

Q. **WHAT IS YOUR RECOMMENDATION CONCERNING THE ALLOCATION OF A REVENUE INCREASE, OR DECREASE, ORDERED BY THE COMMISSION FOR ENERGYNORTH IN THIS PROCEEDING?**

A. As indicated in the previous section of my testimony, I find that EnergyNorth's MCOSS should not be used to determine the distribution of a revenue increase or decrease which the Commission determines is warranted in this proceeding. Given

[2] *Principles of Public Utility Rates*, Second Edition, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen; Public Utility Reports, Inc. (1988) at 383-384.

the failure of the Company to provide a reasonable MCOSS, I recommend that any increase or decrease which the Commission determines is warranted in this proceeding be distributed by adjusting the revenues to be recovered from each rate class by the system average increase or decrease.

V. RATE DESIGN

Q. **PLEASE DESCRIBE ENERGYNORTH'S CURRENT RESIDENTIAL RATE STRUCTURE.**

A. EnergyNorth's current Residential distribution rates consist of a monthly customer charge and a delivery charge.

Q. **WHAT IS YOUR RECOMMENDATION CONCERNING RESIDENTIAL RATES IF THE COMMISION DETERMINES THAT A RATE INCREASE IS APPROPRIATE IN THIS PROCEEDING?**

A. If the Commission determines that an increase in rates is appropriate, maintaining EnergyNorth's current fixed Residential monthly customer charges would provide customers with greater control over their heating bills by increasing volumetric delivery charges and, therefore, provide customers with a greater incentive to conserve energy and promote energy efficiency. No matter how diligently customers might attempt to conserve energy, they cannot reduce fixed monthly charges. The promotion of energy conservation and energy efficiency is consistent with the State's Energy Policy in RSA 378:37. Therefore, I recommend that if an increase is approved by the Commission, EnergyNorth's current fixed Residential monthly customer charges be maintained and the increase assigned to the Residential class be recovered through increases in delivery charges.

Q. **WHAT IS YOUR RECOMMENDATION CONCERNING RESIDENTIAL RATES IF THE COMMISSION DETERMINES THAT A DECREASE IN ENERGYNORTH'S RATES IS APPROPRIATE?**

A. If the Commission determines that a decrease in EnergyNorth's rates is appropriate, I recommend that the Company's existing delivery charges be maintained and that Residential customer charges be decrease by the amount of the decrease allocated to the Residential class. This would provide customers with greater control over their heating bills by decreasing fixed charges, and provide for increased promotion of energy efficiency and conservation as adopted in Senate Bill 191-FN-A.

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does at this time.