NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

RONALD J. AMEN

AND

JOHN D. TAYLOR

ATRIUM ECONOMICS, LLC

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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SCHEDULES

I. INTRODUCTION

Q. Please state your names and business address.

A. Our names are Ronald J. Amen and John D. Taylor. Our business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926.

Q. On whose behalf are you appearing in this proceeding?

A. We are appearing on behalf of Northern Utilities, Inc. ("Northern" or the "Company"). Northern has retained Atrium to conduct the weather normalization and annualization of its billing determinants; the allocated class cost of service study ("ACOSS"); the marginal class cost of service study ("MCOSS"); the revenue apportionment and revenue targets by class; and the rate design for existing rate classes.

Q. By whom are you employed and in what capacity?

A. We are employed by Atrium Economics, LLC ("Atrium") as Managing Partners.

Q. Have you prepared an Appendix describing your professional qualifications?

A. Yes. Appendix A to our direct testimony presents our professional qualifications.

Q. Please describe Atrium's business activities.

A. Atrium offers a complete array of rate case support services including advisory and expert witness services relating to revenue recovery, pricing, integration of technology, distributed generation, and affiliate transactions. We have extensive experience in rate case management; revenue requirement development; allocated embedded and marginal cost of service studies; rate design and rate alignment; and affiliate and shared services.

We have appeared as expert witnesses on behalf of energy utilities in regulatory proceedings across North America supporting financial, economic, and technical studies before numerous state and provincial regulatory bodies, as well as before the Federal Energy Regulatory Commission (FERC). The Atrium Team has extensive background and experience both in management positions inside electric and gas utilities and as advisors to our clients.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. We have provided pre-filed direct testimony in Unitil Energy Systems Inc. 2021 general rate case, Docket No. DE 21-030.

Q. Please summarize the topics addressed in your testimony.

A. Atrium analyzed Northern's respective historical actual and normal weather data sourced from the National Oceanographic and Atmospheric Administration ("NOAA") to determine the basis for the establishment of normalized sales and transportation throughput for purposes of determining the Company's weather-normalized pro forma billing determinants and revenues in its general rate case.

Our testimony discusses the role of the ACOSS and MCOSS in providing guidance toward designing economically efficient rates. Cost causation is a fundamental principle for these studies. Understanding cost causation requires an indepth understanding of the planning and operation of the utility system, as well as the basic economics of the gas system components.

The ACOSS and MCOSS prepared for this case reveal how Northern incurs costs to serve its various classes of customers. The single most important conclusion from the cost studies is that in order to collect the costs from customers who cause the costs to be incurred, rates must better reflect the nature of these costs.

Finally, Atrium will sponsor the Company's proposed revenue requirement apportionment and rate design proposals, and the resulting bill impacts by rate class.

II. WEATHER NORMALIZATION

Q. Please define weather normalization within the context of Northern's rate case filing.

A. Weather normalization is the process of determining a representative level of gas sales and transportation throughput for the Company's 2020 test year under a predefined level of normal weather conditions, which is represented by an historical average level of Effective Degree Days ("EDD"). EDD reflect an adjustment to standard heating degree days for the effect of wind speed on temperature. Northern has consistently relied on EDD for its weather analysis based on its demonstrated high correlation with the Company's gas throughput.

Q. What is the Company's basis for determining normal weather for its New Hampshire gas distribution system?

A. Northern defines normal weather as the average annual EDD over the most recent 20-year period. Based on a 2020 energy industry survey,[1] 20-year normal weather is the most commonly used normal weather period in the energy industry. The Company provided Atrium with daily actual and normal EDD data for the 20-year period ending December 2020.

Q. Please describe the weather normalization method employed by Atrium.

A. Atrium used actual "per books" billing month consumption volumes by customer class to determine actual average use per customer per day. Regression analysis was then performed for this usage data against actual EDD for the most recent five-year period, or 60 months, for each customer class. Resulting base load per customer and heating coefficients per EDD by class were then applied to actual monthly customers and normal EDD, respectively. Our normalization calculations employed an adjusted base load factor statistic from the regression analysis for each winter month to account for the effect of winter weather on base load usage. The monthly weather adjustment resulted from the difference between the normal and actual 2020 monthly therms. In some months, actual weather was warmer than normal while in other months the weather was colder. In total, the weather for test year 2020 was warmer than normal, resulting in a positive net weather adjustment to throughput of approximately five million therms, as shown in column L of Schedule RAJT-2, labeled "WN Therm Adjustment." Two customer classes, G50/T50 (Low Annual,

[1] *Forecast Accuracy Benchmarking Survey and Energy Trends*, Itron, 2020, copyright protected (Proprietary and Confidential).

Low Winter) and G52/T52 (High Annual, Low Winter) were not weather normalized, as the regression results for these classes did not indicate statistically significant heat sensitivity.

Q. Please describe the net revenue adjustment for each customer class resulting from Atrium's weather normalization process.

A. The weather adjustment therms in column L of Schedule RAJT-2 were multiplied by the volumetric block rate components in each rate schedule to derive the weather normalized revenue impact for each class, as shown in column M of Schedule RAJT-2, labeled "WM Revenue Adjustment."

III. PRO FORMA BILLING DETERMINANTS

Q. Please describe the development of the proforma billing determinants and revenues at current rates.

A. A Customer Annualization Adjustment, as shown in Schedule RAJT-2, was performed using the test year-end number of customers by class to determine the Year-End Customer Adjustment (column P) and Annualization Therm Adjustment (column Q) by class. The respective numerical adjustments were priced at the corresponding current customer charges and volumetric block rates to determine the Annualization Revenue Adjustment by class (column T).

Q. Has there been any further adjustments to class billing determinants or proforma revenues?

A. Yes. An annualization adjustment was made for Rate R-10, Residential Heating, Low

Income, to reflect a change in the customer charge for the months of November and December of the test year. This adjustment is shown in column U of Schedule RAJT-2. The Pro Forma Total Therm Adjustments and corresponding Revenue Adjustments by class are shown in columns V and W respectively, of Schedule RAJT-2.

Q. Have the pro forma billing determinants been reflected the Northern's Revenue Proof?

A. Yes. The preceding weather normalization and annualization adjustments are the basis for the pro forma 2020 Adjusted Billing Determinants and 2020 Adjusted Base Year Revenue at Current Rates in the Revenue Proof and Rate Design, Schedule RAJT-11.

Q. Has Atrium provided calendar month consumption information by customer class?

A. Yes. Atrium developed calendarized revenues per customer by class from the monthly billing cycle revenue per customer. Ratios of billing cycle consumption occurring in the same calendar month were used to allocate monthly billing cycle revenues by class to the corresponding calendar month basis. Monthly calendarized revenues per customer by class will be used in Northern's proposed decoupling mechanism, sponsored by witness Mr. Timothy S. Lyons. Schedule RAJT-12 provides a summary of the calendar month revenue per customer analysis by class.

IV. PURPOSE AND PRINCIPLES OF COST ALLOCATION

Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an embedded ACOSS is a useful tool for determining the allocation of Northern's revenue requirement among its customer classes. It is also a useful tool for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

Q. Please describe the various types of cost of service studies that may be useful to a utility for rate design and the allocation of revenue requirements.

A. In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the incremental change in costs associated with a one-unit change in service (or output) provided by the utility. As a result of using an incremental change, capacity additions tend to be lumpy – meaning that they may add more capacity than required to serve the increment of load assumed in the analysis. To avoid this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecast test year or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

Q. Please discuss the reasons that cost of service studies are utilized in regulatory proceedings.

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more classes, or the cost of providing multiple products to the same class, use the same facilities and the use by one class precludes the use by another class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, main costs vary with either growing design day demand or a growing number of customers.

Finally, utility costs exhibit significant economies of scale. Scale economies result in declining average cost as gas throughput increases and marginal costs must be below average costs. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, on either a marginal or embedded cost basis, requires an understanding of the operating characteristics of the utility system. Further, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. Please discuss the application of economic theory to cost allocation.

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the cost information per unit of demand, customer, and energy developed in the cost of service study to understand and quantify the allocated costs in each customer class is a useful step in the rate design process to guide the development of rates.

However, the existence of common costs makes any allocation of costs problematic from a strict economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds the incremental cost of providing service but is less than stand-alone costs ("SAC"). The logic for this concept is that if customers' prices exceed incremental cost, those customers contribute to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

Q. If any allocation of common cost is problematic from a theoretical perspective, how is it possible to meet the practical requirements of cost allocation?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of *cost causation*. Cost causation, as alluded to earlier, addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers.

An important element in the selection and development of a reasonable ACOSS allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

Q. Why are the relationships between customer requirements, load profiles and usage characteristics significant to cost causation?

A. The Company's distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate design day peak capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They generally include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the Company for its sales service customers.

Q. How does one establish the cost and utility service relationships you previously discussed?

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records as well as its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

In order to accomplish this, Atrium reviewed Northern’s expense and plant accounts, operational data, usage information, and conducted interviews with Northern employees. The details and data gathered provided information on the key factors that cause the costs to vary and supported studies of the relative costs of providing facilities and services for each rate class. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain what you mean by the term "direct assignment."

A. The term direct assignment relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing an ACOSS, the analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer group to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

Q. What prompts the analyst to elect to perform a special study?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. How do you determine whether to directly assign costs to a particular customer or customer class?

A. Direct assignments of plant and expenses to specific customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records, and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities, as mentioned earlier. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign or allocate the remaining costs to the rate classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. Please describe the process of performing an ACOSS analysis?

A. In order to establish the cost responsibility of each customer class, initially a three-step analysis of the utility's total operating costs must be undertaken: (1) functionalization; (2) classification; and (3) allocation.

The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. Northern's primary functional cost categories associated with gas service include production, distribution, onsite, and customer accounts and services. Indirect costs that support these functions, such as intangible plant, general plant, and administrative and general expenses, are allocated to functions using allocation factors related to plant and/or labor ratios, i.e., internal allocation factors.

Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer, (2) demand or capacity, and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer class. Costs typically are allocated on customer, demand, commodity, or revenue allocation factors.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred by a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the way customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics and have different costs based on size and type.

Therefore, differences in the cost of meters are reflected by using a different average meter cost for each class of service.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing an ACOSS?

A. Yes. The factors which can influence the cost allocation used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. Why are these considerations relevant to conducting Northern's ACOSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the state the utility operates in as it pertains to cost of service studies and gas ratemaking issues.

Q. Please explain why the physical configuration of the system is an important consideration.

A. The particulars of the physical configuration of the distribution system are important, such as whether the distribution system is a centralized or a dispersed one. Other such characteristics are whether the utility has a single city-gate or a multiple city-gate configuration, whether the utility has an integrated transmission and distribution system or a distribution-only operation, and whether the system is a multiple-pressure based or a single pressure-based operation.

Q. How does the availability of data influence an ACOSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region, and the types of load data available.

Q. How do state regulatory policies affect a utility's ACOSS?

A. State regulatory policies and requirements prescribe whether there are any historical precedents used to establish utility rates in the state. Specifically, state regulations and past precedents set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

V. NORTHERN'S ALLOCATED COST OF SERVICE STUDY

Q. What was the source of the cost data analyzed in the Company's ACOSS?

A. All cost of service data was extracted from the Company's total cost of service (i.e., total revenue requirement) and schedules contained in this filing. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

Q. How are the Northern rate classes structured for purposes of conducting its ACOSS?

A. For Northern's ACOSS, eight rate classes were included:

- Residential Heating Service (Rate R-5) and Residential Low Income (R-10)
- Residential Non Heating Service (R-6)
- Commercial & Industrial Service (Low Annual, High Winter) (G-40, T-40)
- Commercial & Industrial Service (Low Annual, Low Winter) (G-50, T-50)
- Commercial & Industrial Service (Medium Annual, High Winter) (G-41, T-41)
- Commercial & Industrial Service (Medium Annual, Low Winter) (G-51, T-51)
- Commercial & Industrial Service (High Annual, High Winter) (G-42, T-42)
- Commercial & Industrial Service (High Annual, Low Winter) (G-52, T-52)

Q. What are the similarities and differences in the cost allocation approach utilized in Northern's ACOSS in this proceeding with that utilized in Northern's previous rate case?

A. With the exception of the classification and allocation of Distribution Mains, the general methods employed in Northern's previous general rate case proceeding, Docket No. DG 17-070 ("2017 Case"), are reflected in the ACOSS methods employed in the current proceeding and described in my testimony. Updated data was utilized to develop the special studies and analyses that inform the calculations and outcome of the ACOSS, but the general approaches used in the current proceeding are in alignment with the 2017 Case. The primary studies are summarized below:

<u>Indirect Production & Overheads Study</u> – The Atrium ACOSS is fully

unbundled; therefore, the costs in this category are captured in the Function of the same name. The prior case had separate cost of service studies for Production only and Delivery only.

LNG Storage – LNG Storage plant and O&M costs are included in the Indirect Production & Overheads function and allocated based on the design day for each class. In the 2017 Case LNG Storage costs were included in the Production only cost of service study and allocated on the ratio of remaining design day demands.

Classification of Distribution Mains – Mains are classified between a customer component and a demand component, as described in more detail below. In the prior rate case, Mains were classified as 100% demand related.

Special Studies – Atrium's ACOSS included special studies for meters, services, other revenue, uncollectible costs, meter reading, and customer deposits. Studies from the prior rate case included meters, services, uncollectible costs, and customer deposits.

Q. How did the Company's ACOSS classify and allocate investment in Distribution Mains?

A. The Company ACOSS classified 34% of the investment in distribution mains as customer related and 66% of the investment as demand related. The customer related portion of the distribution mains investment was then allocated based on the number of customers on Northern's system. The demand related investment was allocated to the customer classes based on their respective contribution to peak day demand under system design weather conditions, in other words, on a “design day” basis.

Q. Please explain the basis for the choice of classification and allocation methods?

A. It is widely accepted that distribution mains are installed to meet both system peak period load requirements and to connect customers to the utility's gas system. Therefore, to ensure that the rate classes that cause the Company to incur this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and number of customers.

There are two cost factors that influence the level of distribution mains facilities installed by a utility in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the gas distribution system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the utility.

Q. Is this method used to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, which is the method relied upon in the Company's cost study, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the Company's gas system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the Company's distribution system, regardless of the customer's peak or annual gas consumption; that is, the installation is unrelated to either peak gas flows or average gas flows. Rather, these distinct costs are related more strongly to the process of extending the distribution mains to connect customers, which is a function of the length of distribution mains and not of the size or diameter of the mains.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. For purposes of determining the customer component of distribution mains to be used in Northern's ACOSS, the minimum system method was employed to test the reasonableness, by comparison, of the results of the zero-intercept method.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC"), and Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

From an overall regulatory perspective, in its publication entitled, Gas Rate Design Manual, NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment.

Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q. With respect to Northern's specific operating experience, is there demonstrable evidence to support the use of a customer component of distribution mains?

A. Yes. In developing an appropriate cost allocation basis for distribution mains, the two methods of cost analysis mentioned in the previous response were conducted for the Company's investment in distribution mains, by size and material type of main installed. Applying the regression results of the "zero inch" distribution main, which was $25.21 per foot for plastic mains, to the Company's total footage of distribution mains results in an investment amount equivalent to approximately 34% of the total investment in distribution mains, on a current cost (year 2020) basis. For the purpose of comparison, the most commonly installed, minimum-sized distribution mains analysis focused on 2-inch diameter plastic pipe. The dominant pipe size for new distribution main installations by far is 2-inch plastic, with over 1.2 million feet installed. The 2-inch plastic pipe analysis, adjusted downward to account for its load carrying capacity, yielded a minimum system result of 41.5%. These results are provided in Schedule RAJT-9 - Customer Component of Mains Analysis. Both methods are supportive of the 34% classification of distribution mains as customer related used in the ACOSS model.

Q. Would one expect there to be a strong correlation between the number of customers served by Northern and the length of its system of distribution mains?

A. Yes. Development of the Company's distribution grid over time is a dynamic process. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as a static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand and appreciate that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's "off-system" location.

Recognizing that the goal is to more reasonably classify and allocate the total cost of Northern's distribution mains facilities, it is appropriate to analyze the cost causation factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a minimum system approach for classifying distribution mains simply reflects the fact that the average customer serviced by the Company requires a minimum amount of mains investment to receive such service. Thus, it is entirely appropriate to conclude that the number of customers served by Northern represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. One can readily conclude that a customer component of distribution mains is a distinct and separate cost category that has much support from an engineering and operating standpoint.

Q. How did the ACOSS allocate distribution-related gas operation and maintenance ("O&M") expenses?

A. In general, these expenses are allocated based on the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of plant facilities necessitates the incurrence of cost, *i.e.*, expenses by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account No. 887, Maintenance of Mains, is allocated on the same basis as its corresponding plant accounts, Mains – Account No. 376. With the detailed analyses supporting the assignment or allocation of major plant in service components; where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

Q. Please describe the classification and allocation of Customer Accounts and Customer Service expenses in the COSS.

A. Customer accounts and services expenses were classified as customer-related costs and allocated based on the average number of distribution customers by class. Exceptions to this treatment were Account Nos. 902 (Meter Reading) and 904 (Uncollectible Accounts). The allocation factor for meter reading expenses included additional time and effort related to meter reading for manual meter reading activities. Uncollectible accounts expenses are assigned to the classes based on an analysis of bad debt expenses.

Q. How were administrative and general ("A&G") expenses and taxes allocated to each rate class?

A. A&G expenses were allocated on an account-by-account basis. Items related to labor costs, such as employee pensions and benefits, were allocated based on O&M labor costs. Items related to plant, such as maintenance of general plant and property taxes, were allocated based on plant. Regulatory Commission expense was allocated on rate base.

Q. Please describe the method used to allocate the reserve for depreciation as well as depreciation expenses.

A. These items were allocated by function in proportion to their associated plant accounts.

Q. How did the COSS allocate taxes other than income taxes?

A. The study allocated all taxes, except for income taxes, in a manner which reflected the specific cost associated with each tax expense category. Generally, taxes can be cost classified on the basis of the tax assessment method established for each tax category and can be grouped into the following categories: (1) labor; (2) plant; and (3) rate base. In the Northern COSS, all non-income taxes were assigned to one of the above stated categories which were then used as a basis to establish an appropriate allocation factor for each tax account.

Q. How were income taxes allocated to each rate class?

A. Current income taxes were allocated based on each class' net income before taxes. Income taxes for the total revenue requirement were allocated to each class based on the allocation of rate base to each class. Income taxes at proposed revenues by class were allocated to each class based on the income prior to taxes for each class.

Q. Does Northern's COSS include gas commodity costs?

A. No. However, there are indirect production and overhead costs within the COSS which are recovered through the Company's Cost of Gas Adjustment mechanism. The details relating to these costs and the associated revenue requirement of $826,413 are presented in Schedule RAJT-3, Summary of Cost Functionalization.

VI. SUMMARY OF THE ALLOCATED COST OF SERVICE STUDY

Q. Please summarize the results of Northern's COSS.

A. The following **Table 1** provides a high-level summary of the results of the ACOSS. It shows the rate of return for each rate class based on current rates as well as the system overall return, the revenue deficiency or excess for each rate class at the uniform system rate of return, and the revenue-to-cost ratio for each class.

Table 1

Summary Results of the Company's ACOSS

Rate Class	Class Revenue (Deficiency)/ Excess	Rate of Return on Net Rate Base	Revenue to Cost Ratio
Residential HeatR-5, R-10	(5,235,399)	3.58%	0.82
Residential Non-HeatR-6, R-11	(484,346)	-5.61%	0.54
High Winter SmallG-40, T-40	(1,486,126)	4.48%	0.84
Low Winter Small G-50, T-50	49,432	10.37%	1.05
High Winter MediumG-41, T-41	(1,180,973)	4.81%	0.83
Low Winter MediumG-51, T-51	106,343	11.29%	1.09
High Winter LargeG-42, T-42	(480,404)	3.91%	0.78
Low Winter LargeG-52, T-52	697,045	16.74%	1.35
Total Company	(8,014,427)	4.74%	0.85

Regarding rate class revenue levels, the resulting revenue-to-cost ratios show that all but three classes, Low Winter Small (G-50, T-50), Low Winter Medium (G-51, T-51, and Low Winter Large (G-52, G-T-52) are being charged rates that recover less than their indicated costs of service.

Q. Do these results provide guidance for the allocation of revenue requirements in this case?

A. Yes. Cost of service is a useful tool for determining the allocation of the revenue deficiency to each rate class. Cost of service is not, however, the only consideration in determining the portion of the revenue deficiency allocated to each rate class. Other considerations include principles such as gradualism, competitive considerations, standalone costs and avoiding or minimizing the potential for compromising the integrity of current rate classes.

Q. Has Northern taken the above factors into account in recommending the level of rate increase for rate classes?

A. Yes. The process for determining the revenue increase for each class is addressed in **Section V** of this testimony.

Q. Please describe the ACOSS schedules attached to this testimony.

A. Five schedules provide further details of the ACOSS that include the following information:

- Schedule RAJT-4 consists of two pages and presents the results of the class cost of service study for the test year. Class rate of return and net income may be found on page 1, and the revenue requirement for each class at the uniform rate of return by rate schedule is shown on page 2 of this schedule.
- Schedule RAJT-5 provides a single page illustration of the process followed to develop the Company's proposed class revenue allocation.

- Schedule RAJT-6 consists of 3 pages and presents the ACOSS unit cost report.
- Schedule RAJ-7 consists of 2 pages and provides the summary of the ACOSS external allocation factors.
- Schedule RAJT-8 consists of 5 pages and provides a description of the functionalization and classification of the USOA accounts.

VII. MARGINAL COST OF SERVICE STUDY

Q. Please describe the purpose for the preparation of a marginal cost of service study?

A. Marginal cost of service studies do not typically reflect actual costs but rely on estimates of the expected changes in costs associated with changes in service levels; and are therefore, forward-looking to the extent permitted by the available cost data. Marginal cost studies are most useful for rate design where it is important to send appropriate price signals associated with additional consumption by customers. Marginal cost studies can inform rate design particularly as it relates to customer and demand related costs for a utility that provides default supply services to retail customers who do not elect an alternate gas commodity supplier.

Q. Please describe the Company's MCOSS.

A. Marginal cost studies focus on the change in costs associated with a small change in the number of customers or load added to the utility's system, or the cost to replace the current customer related infrastructure to continue service to an existing customer. As stated earlier, marginal costs are generally forward-looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of actual historical costs that constitute the utility revenue requirement. The reasons that marginal costs do not reflect actual costs used in a utility's revenue requirement calculations include the following:

- The relationship between historic and prospective costs reflects changes in technology.
- Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement particularly where economies of scale are significant.
- The underlying impacts of inflation on prospective costs cause such costs to differ from past costs.
- Additions to the utility system are lumpy, and as a result, utilities' optimal additions often include more capacity than the marginal change in customer count or customer demand.

An example of the latter point is addressed in Northern's system improvement planning process:

"Unlike mains extensions that are installed to serve known load, system improvements are completed in advance to ensure the system has the capacity required to meet planning criteria. The capacity increase associated with system improvement projects tend to be a lumpy investment, meaning that the amount of capacity is determined based upon standard equipment and materials and is not able to be fine-tuned to the amount of load forecasted."[2]

Q. Please discuss the steps followed to prepare a MCOSS for a gas utility such as Northern.

A. To estimate marginal cost, the first step requires determining the change in cost associated with the incremental consumption of natural gas. The increment may be defined as the number of customers, the design day demand, or the additional commodity. In this case, there is no reason to estimate the incremental commodity cost because gas costs are a pass-through cost element. Essentially, marginal cost requires an understanding of the utility's system planning process. Often however, the planning process does not provide all of the information necessary to develop complete marginal cost estimates.

The second step in the determination of marginal cost relates to the change in capacity requirements as measured by the utility's design day demand. Unlike the commodity determination, there is no competitive market for the utility's distribution function. Thus, it is necessary to estimate how customers' demand for design day capacity influences the costs for distribution. Gas distribution systems are typically built using engineering design standards that take into consideration customer density and the expected design day demands of those customers. For customers who use the utility's gas delivery system for heating as opposed to process usage or interruptible

[2] Direct Testimony of Kevin E. Sprague and Christopher J. LeBlanc, at 12:9-14.

services, their demands tend to be coincident. Distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is designed based on the design load of the customers to be served.

The concept of a network cost provides a convenient way to discuss the marginal distribution costs. Network costs represent the cost of the interconnected facilities that serve distribution system demand and include mains, service lines and meters. The customer component of these facilities is related to the smallest size of the equipment that is installed to serve customers. If larger equipment is installed, the extra costs are demand related. The economies of scale in the distribution system means that the demand related cost is often less significant than the customer component. It also means that per unit cost of serving larger customers is lower than the cost to serve smaller customers.

Q. How have you identified the minimum size components used by Northern's distribution system?

A. Yes. The distribution engineering and operations personnel at Northern were interviewed to gain an understanding of the smallest standard size of facilities used. In addition, the Company's accounting function personnel were consulted to determine the fully loaded installed costs of these components. The customer component of distribution mains, which informs the minimum system, is discussed in **Section V**, Northern's Allocated Cost of Service Study. Meters and services are considered entirely customer related. The MCOSS schedule also provides the economic carrying charge rate for each plant component. The schedule produces the marginal revenue requirement for Northern associated with customer and demand related capital expenditures. The economic carrying charge rate uses Northern's marginal capital costs based on the current filing. The forward-looking nature of a marginal cost study requires that the capital cost be estimated on an incremental basis not on embedded costs.

Q. Did you identify the general plant related to the minimum system?

A. Yes, the customer and demand related general plant was identified based on average embedded costs as a proxy for long-run marginal costs.

Q. Why are average embedded costs a reasonable proxy for marginal costs?

A. General plant costs do not vary directly with either demand or customers. That is the reason that in the allocated cost of service they are allocated on composite allocation factors. For example, customer growth only impacts the number of employees and therefore payroll expense when large discreet blocks of customers are added. If we used a pure marginal cost allocation factor, the payroll component growth related to customers or demand would be zero for a number of years and would be the full cost of a new employee only when the threshold number of customers requiring additional employees reached the tipping point in the level of services provided. By using an average cost value, the marginal cost study recognizes the contribution of each new customer to the future requirement of a new employee or new office space.

Q. Have you identified the customer related expenses?

A. Yes. The customer related expenses may be found in Schedule RJA-10, which presents the Company's full marginal cost study. These expenses were based on embedded costs as a proxy for long-run marginal costs. In the short run, these costs would be zero because adding one customer does not change most of these costs. However, at some level these costs would increase by an amount related to the average cost when a minimum number of customers have been added. This approach provides a reasonable proxy for the O&M related costs.

Q. Did you identify the A&G costs related to the minimum system?

A. Yes, customer and demand related A&G costs were identified based on embedded costs as a proxy for long-run marginal costs.

Q. Please summarize the results of the company's customer and demand costs on an embedded and a marginal cost basis.

A. The results are summarized in **Table 2** below.

Table 2

Summary of Unit Costs by Class

Rate Class	Unit Customer Costs ($/Month)		Unit Demand Cost ($/DDDth-Month)	
	(B)	(C)	(D)	(E)
	Embedded	Marginal	Embedded	Marginal
Residential HeatR-5, R-10	71.71	56.20	21.04	24.69
Residential Non-HeatR-6, R-11	72.33	56.05	21.04	24.69
High Winter SmallG-40, T-40	86.60	71.71	21.04	24.69
Low Winter Small G-50, T-50	86.76	71.91	21.04	24.69
High Winter MediumG-41, T-41	187.51	159.07	21.04	24.69
Low Winter MediumG-51, T-51	187.21	160.87	21.04	24.69
High Winter LargeG-42, T-42	725.70	720.13	21.04	24.69
Low Winter LargeG-52, T-52	736.61	729.25	21.04	24.69
Total System	78.70	62.94	21.04	24.69

As the table illustrates, the Residential customer-related costs calculated in both cost studies are significantly greater than the current customer charge. Thus, a customer facilities-related charge increase is warranted and consistent with the indicated cost of service. Increasing the customer charge and reducing the volumetric charge is also consistent with both marginal cost pricing and achieving just and reasonable rates.

Q. Would the proposed allocation of the company's proposed revenue requirements differ based on using marginal costs instead of embedded costs?

A. Any differences would not be material. Considering the Company's proposed revenue allocation, the end result would have been the same. However, there is more long-term stability in embedded costs, and it is more reflective of the cost causation principle. Therefore, I believe the ACOSS is a more reasonable alternative.

VIII. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design utilized in development of the

Company's rate design proposals.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

(1) Cost of Service,

(2) Efficiency,

(3) Value of Service,

(4) Stability/Gradualism,

(5) Non-Discrimination,

(6) Administrative Simplicity, and

(7) Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[3]

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of

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[3] Principles of Public Utility Rates, Second Edition, Page 111-113 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service. This principle puts the concept of SAC, discussed earlier, into practice and is particularly relevant for Northern because of the competitive supply alternatives that cap rates under its flex rates.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal – rates should be equal and, where costs are different – rates should be different.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that was previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. As noted above, there are tensions between cost and value of service principles. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process must be, in part, influenced by judgmental evaluations.

IX. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Northern's proposed revenue increase of $7.8 million to its customer classes.

A. As just described, the apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for Northern's customer classes.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Northern's interclass revenue proposal?

A. Yes. Using Northern's proposed revenue increase, and the results of its COSS, Atrium evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Northern personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option evaluated under Northern's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00 (Unity), as shown in Schedule RAJT-5, Proposed Revenue Allocation by Class, under *Scenario A - Revenues at Equalized Rates of Return*. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

A second option considered was assigning the increase in revenues to Northern's customer classes based on an equal percentage basis of its current non-gas revenues (see *Scenario B - Equal Percentage Increase*, in Schedule RAJT-5). By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS Study results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of Northern's customer classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). In fact, the disparity in cost responsibility between the classes was widened. While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop Northern's class revenue proposal.

Q. What was the result of this process?

A. After further discussions with Northern, Atrium concluded that the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all of Northern's customer classes while the minimum class increase is set to fifty percent of the system average, as shown in Schedule RJA-5 as *Proposed Class Revenues*. In the case of the Residential Heat class (R-5/R-10), the revenue adjustment at 1.25 times the system average ensures their proposed rates will move class revenues closer to the allocated cost of service for the class at 0.95 revenue-to-cost ratio. The proposed revenue increase to the Residential Non-Heat (R-6/R-11) class of twice the system average increase will improve the class' revenue-to-cost ratio from 0.45 to 0.63, below unity (1.00) at the Company's proposed ROR of 7.75%. Proposed increases for the G-40/T-40, G-41/T-41, and G-42/T42 classes were 75% of the system average increase, which brings their revenue-to-cost ratios 0.96, 1.08 and 1.05, respectively. The ACOSS results for the remaining customer classes (G-50/T50, G-51/T-51, G-52/T-52) indicate their respective class rates of return are at or above the system average rate of return at both the Company's current and proposed ROR levels. While this would suggest the need for revenue decreases in order to move many of these customer classes closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00), as shown in Schedule RJA-5 under *Revenues at Equalized Rates of Return*, the resulting customer impact implications for the Residential Service classes has led us to conclude, in consultation with the Company, to refrain from revenue reductions for these classes or alternatively exempting these classes from revenue increases (*Scenario B*). Instead, the proposed respective revenue adjustments of 50% of the system average increase will mean these two classes will be higher than their current parity ratio levels relative to unity. The resulting allocation of the total revenue increase of $7,782,951 to the respective rate classes is presented in **Table 3**, below.

Table 3

Proposed Class Revenue Apportionment

Rate Class	Revenues at Current Rates	Revenues at Proposed Rates	Proposed Revenue Change	Percent Change	Revenue to Cost Ratio
Residential HeatR-5, R-10	20,731,783	25,996,394	5,264,611	25.39%	0.95
Residential Non-HeatR-6, R-11	493,626	692,442	198,816	40.28%	0.65
High Winter SmallG-40, T-40	6,745,829	7,764,703	1,018,874	15.10%	0.96
Low Winter Small G-50, T-50	1,024,226	1,127,357	103,131	10.07%	1.10
High Winter MediumG-41, T-41	5,235,691	6,026,477	790,786	15.10%	1.08
Low Winter MediumG-51, T-51	1,396,947	1,537,608	140,661	10.07%	1.27
High Winter LargeG-42, T-42	1,545,114	1,778,485	233,370	15.10%	1.04
Low Winter LargeG-52, T-52	2,623,624	2,887,802	264,177	10.07%	1.75
Special Contracts Revenue	1,197,813	1,197,813	0	0.00%	
Indirect Production & OH Revenue	1,057,890	826,413	-231,477	-21.88%	
Miscellaneous Revenue	1,147,705	1,147,705	0	0.00%	
Total Company	43,200,249	50,983,199	7,782,951	18.02%	1.00

Q. Please summarize the overall benefit provided by your proposed class revenue apportionment.

A. In summary, the preferred revenue allocation approach in Schedule RJA-5, *Scenario C* results in reasonable movement of the Residential and High Winter Small Commercial classes revenue-to-cost ratios toward unity or 1.00, while providing moderation of the revenue impact on this class by requiring varying levels of revenue increase responsibility from the other customer classes for the Company's total proposed revenue requirement. From a class cost of service standpoint, this type of class movement, and modest reduction in the existing class rate subsidies, is desirable.

X. NORTHERN'S RATE DESIGN

Q. Please summarize the proposed rate design changes.

A. In consultation with Northern, Atrium is proposing changes to monthly customer charges. We are recommending an increase to the Residential (R-5/R-10, R-6) customer charges equal to the percentage revenue increase (25.4%) to the Residential Heat class from $22.20 to $27.84 per month. Modest increases were made to the customer charges for the remaining non-residential rate schedules.

Atrium is also proposing to remove all seasonally differentiated volumetric rates in the rate schedules where the winter/summer rates remain with one exception; that is, Rate Schedule G-52/T-52. While there is no demonstrable cost of service support for the current seasonal differences in the rates, eliminating the winter/summer rate differential will cause disproportionate increases for G-52/T-52 customers with primarily summer season consumption.

Finally, all rate schedules with current multi-block volumetric rates have been reduced to a single flat block, which continues the transition of the volumetric rates from Northern's 2017 rate case. These proposed changes to the volumetric rates will simplify bill calculation and presentation of the information on customer bills, in addition to the monthly revenue per customer by class calculations used in the Company's proposed decoupling mechanism, and provide some winter bill reductions to heating load customers when monthly bills are the highest.

Q. Have you provided a schedule detailing the proposed rates and corresponding revenues?

A. Yes. Schedule RAJT-11, Revenue Proof and Rate Design, presents summaries by customer class of the proposed revenue increases. This schedule displays the revenues calculated under the present and proposed rates for each customer rate schedule. The proposed revenue increase by class and corresponding percentages are also shown.

XI. CUSTOMER BILL IMPACTS

Q. What are the corresponding bill comparisons for Northern's customers served under its various rate schedules?

A. A presentation of the billing impacts based on class average monthly usage by winter and summer seasons, and presented in deciles of usage, are provided for all rate schedules in Schedule RAJT-13, Customer Bill Impacts.

Q. Has Northern prepared additional bill comparisons for its Residential customers?

A. Yes. The annual bill impacts, as shown on a month-by-month basis, for the Residential rate schedules are provided in Schedule RAJT-14, Residential Customer Bill Impacts.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

Docket No. DG 21-104
Schedule RAJT-2
Summary of Weather Normalized Billing Determinants

Northern Utilities New Hampshire
Weather Normalization and Customer Annualization

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]
				Per Books					Weather Normalization					
Line	Rate Class	Description	Month	2020 Therms - Summer	2020 Therms - Winter	2020 Therms - Total	2020 Customers	2020 UPC	Normal UPC	2020 Normal Therms	WN Therm Adjustment	WN Therm Adjustment Summer	WN Therm Adjustment Winter	WN Revenue Adjustment
								[G] / [H]	WNA	[H] x [J]	[K] - [G]	[K] - [G]	[K] - [G]	[M] x Rate + [N] x Rate
1	R-5	Residential Heating	January	(11,181)	2,990,270	2,979,089	25,300	117.748	133.131	3,368,269	389,180		389,180	$269,312
2			February	(1,088)	3,028,644	3,027,557	25,213	120.080	139.422	3,515,228	487,671		487,671	$337,469
3		*Rates*	March	(331)	2,582,100	2,581,769	25,370	101.764	115.348	2,926,418	344,649		344,649	$238,497
4		*Customer*	April	(520)	1,794,556	1,794,035	25,211	71.161	77.829	1,962,150	168,115		168,115	$116,336
5		*$22.20*	May	609,620	675,934	1,285,554	25,458	50.496	44.372	1,129,646	(155,908)	(73,933)	(81,975)	-$101,819
6		*Summer*	June	547,616	(9,388)	538,228	25,363	21.221	25.582	648,829	110,601	110,601		$67,456
7		*$0.6099*	July	356,914	(784)	356,130	25,483	13.975	11.294	287,818	(68,312)	(68,312)		-$41,664
8		*Winter*	August	296,799	(535)	296,265	25,442	11.645	9.396	239,056	(57,209)	(57,209)		-$34,892
9		*$0.6920*	September	383,497	0	383,497	25,600	14.981	13.677	350,119	(33,378)	(33,378)		-$20,357
10			October	540,827	894	541,721	25,795	21.001	26.443	682,104	140,383	140,383		$85,620
11			November	684,892	561,474	1,246,367	26,120	47.718	51.958	1,357,123	110,756	60,862	49,894	$71,646
12			December	(283)	2,258,625	2,258,342	26,171	86.291	100.691	2,635,202	376,860		376,860	$260,787
13				3,406,764	13,881,789	17,288,553		678.081	749.144	19,101,961	1,813,408	79,014	1,734,393	$1,248,391
14	R-10	Res. Heating, Low Income	January	585	77,516	78,101	742	105.309	121.181	89,872	11,771		11,771	$8,145
15			February	1,125	86,314	87,439	817	106.994	130.166	106,377	18,937		18,937	$13,105
16		*Rates*	March	331	70,723	71,054	760	93.463	115.534	87,833	16,779		16,779	$11,611
17		*Customer*	April	441	55,771	56,212	879	63.928	82.227	72,302	16,090		16,090	$11,134
18		*$22.20*	May	16,946	18,090	35,036	794	44.142	46.837	37,175	2,139	1,035	1,104	$1,395
19		*Summer*	June	12,319	9,654	21,973	781	28.148	26.009	20,304	(1,669)	(1,669)		-$1,018
20		*$0.6099*	July	7,455	772	8,226	688	11.954	10.336	7,112	(1,114)	(1,114)		-$679
21		*Winter*	August	6,497	464	6,961	663	10.497	8.367	5,549	(1,412)	(1,412)		-$861
22		*$0.6920*	September	7,994	0	7,994	644	12.409	12.880	8,298	304	304		$185
23		*Rates, Jan-Oct*	October	11,941	1	11,943	641	18.631	27.210	17,442	5,499	5,499		$3,354
24		*$8.88*	November	14,175	14,146	28,321	630	44.977	49.718	31,307	2,985	1,494	1,491	$1,943
25		*$0.2440*	December	296	51,744	52,039	644	80.845	86.220	55,499	3,460		3,460	$2,394
26		*$0.2760*		80,105	385,195	465,300		621.298	716.686	539,069	73,769	4,136	69,633	$50,708
27	R-6	Residential Non-Heating	January	17	29,096	29,113	1,267	22.977	25.217	31,951	2,838		2,838	$1,836
28			February	29	28,355	28,384	1,289	22.021	25.601	32,998	4,614		4,614	$2,985
29		*Rates*	March	0	26,031	26,031	1,295	20.094	21.109	27,347	1,316		1,316	$851
30		*Customer*	April	0	21,269	21,269	1,280	16.619	16.378	20,961	(309)		(309)	-$200
31		*$22.20*	May	8,884	9,778	18,661	1,311	14.238	13.681	17,932	(730)	(347)	(382)	-$472
32		*Summer*	June	14,744	0	14,744	1,331	11.074	11.394	15,170	426	426		$275
33		*$0.6470*	July	12,608	0	12,608	1,354	9.312	9.076	12,289	(319)	(319)		-$206
34		*Winter*	August	11,288	0	11,288	1,355	8.329	8.367	11,340	52	52		$34
35		*$0.6470*	September	14,017	0	14,017	1,358	10.320	9.705	13,181	(836)	(836)		-$541
36			October	12,848	5	12,852	1,347	9.543	10.630	14,317	1,464	1,464		$947
37			November	10,298	7,240	17,538	1,312	13.366	13.709	17,988	450	264	186	$291
38			December	0	25,111	25,111	1,277	19.669	20.978	26,783	1,672		1,672	$1,082
39				84,733	146,885	231,617		177.562	185.845	242,254	10,637	703	9,934	$6,882

Northern Utilities New Hampshire
Weather Normalization and Customer Annualization

[A]	[B]	[C]	[D]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]
				Customer Annualization					Rate Change	Pro Forma Adjustment	
Line	Rate Class	Description	Month	Year-End Customer Adjustment	Annualization Therm Adjustment	Annualization Therm Adj. Summer	Annualization Therm Adj. Winter	Annualization Revenue Adjustment	R-10 Rate Change Annualization	Total Therm Adjustment	Test Year Revenue Adjustment
				[H]Dec - [H]	[J] x [P]	[J] x [P]	[J] x [P]	[P]xRt+[R]xRt+[S]xRt	[E]xDif+[H]xDif	[L] + [Q]	[U]+[O]+[T]
1	R-5	Residential Heating	January	871	115,908		115,908	$99,536		505,088	$368,849
2			February	958	133,593		133,593	$113,719		621,265	$451,187
3		*Rates*	March	801	92,379		92,379	$81,705		437,027	$320,202
4		*Customer*	April	960	74,721		74,721	$73,021		242,836	$189,356
5		*$22.20*	May	713	31,620	14,994	16,625	$36,470		(124,289)	-$65,349
6		*Summer*	June	809	20,686	20,686		$30,567		131,287	$98,023
7		*$0.6099*	July	688	7,771	7,771		$20,014		(60,541)	-$21,650
8		*Winter*	August	730	6,856	6,856		$20,378		(50,353)	-$14,513
9		*$0.6920*	September	572	7,818	7,818		$17,458		(25,561)	-$2,900
10			October	376	9,944	9,944		$14,413		150,327	$100,032
11			November	51	2,676	1,470	1,205	$2,874		113,432	$74,521
12			December	0	-		-	$0		376,860	$260,787
13				7,528	503,971	69,538	434,432	$510,154		2,317,378	$1,758,545
14	R-10	Res. Heating, Low Income	January	(98)	(11,868)		(11,868)	-$10,387	$42,339	(97)	$40,097
15			February	(174)	(22,589)		(22,589)	-$19,485	$47,204	(3,652)	$40,824
16		*Rates*	March	(117)	(13,464)		(13,464)	-$11,905	$39,668	3,315	$39,375
17		*Customer*	April	(236)	(19,373)		(19,373)	-$18,637	$35,074	(3,283)	$27,572
18		*$22.20*	May	(150)	(7,026)	(3,398)	(3,628)	-$7,914	$24,298	(4,887)	$17,780
19		*Summer*	June	(137)	(3,562)	(3,562)		-$5,212	$18,922	(5,231)	$12,691
20		*$0.6099*	July	(44)	(459)	(459)		-$1,267	$12,215	(1,573)	$10,268
21		*Winter*	August	(20)	(163)	(163)		-$533	$11,404	(1,576)	$10,010
22		*$0.6920*	September	(1)	(7)	(7)		-$16	$11,506	297	$11,675
23		*Rates, Jan-Oct*	October	3	73	73		$104	$12,908	5,572	$16,366
24		*$8.88*	November	14	697	349	348	$764	$9,655	3,682	$12,363
25		*$0.2440*	December	0	-		-	$0	$108	3,460	$2,502
26		*$0.2760*		(958)	(77,743)	(7,168)	(70,575)	-$74,485	$265,302	(3,974)	$241,525
27	R-6	Residential Non-Heating	January	10	244		244	$372		3,081	$2,208
28			February	(12)	(314)		(314)	-$475		4,300	$2,510
29		*Rates*	March	(19)	(396)		(396)	-$673		919	$178
30		*Customer*	April	(3)	(51)		(51)	-$103		(360)	-$302
31		*$22.20*	May	(34)	(465)	(221)	(243)	-$1,055		(1,194)	-$1,527
32		*Summer*	June	(55)	(623)	(623)		-$1,618		(198)	-$1,342
33		*$0.6470*	July	(77)	(701)	(701)		-$2,169		(1,020)	-$2,375
34		*Winter*	August	(79)	(657)	(657)		-$2,168		(605)	-$2,134
35		*$0.6470*	September	(82)	(791)	(791)		-$2,322		(1,628)	-$2,863
36			October	(70)	(745)	(745)		-$2,039		719	-$1,092
37			November	(35)	(485)	(285)	(200)	-$1,100		(36)	-$809
38			December	0	-		-	$0		1,672	$1,082
39				(456)	(4,986)	(4,024)	(962)	-$13,349		5,651	-$6,467

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Weather Normalization and Customer Annualization

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]
				Per Books					Weather Normalization					
Line	Rate Class	Description	Month	2020 Therms - Summer	2020 Therms - Winter	2020 Therms - Total	2020 Customers	2020 UPC	Normal UPC	2020 Normal Therms	WN Therm Adjustment	WN Therm Adjustment Summer	WN Therm Adjustment Winter	WN Revenue Adjustment
								[G] / [H]	WNA	[H] x [J]	[K] - [G]	[K] - [G]	[K] - [G]	[M] x Rate + [N] x Rate
40	G-40/T-40	Low Annual, High Winter	January	(9)	1,800,364	1,800,355	5,126	351.2	396.3	2,031,250	230,896		230,896	$43,062
41			February	69	1,761,135	1,761,204	5,124	343.7	408.0	2,090,502	329,298		329,298	$61,414
42		*Rates*	March	6	1,471,715	1,471,721	5,128	287.0	337.4	1,729,963	258,243		258,243	$48,162
43		*Customer*	April	(1)	934,832	934,831	5,081	184.0	216.4	1,099,281	164,450		164,450	$30,670
44		*$75.09*	May	297,681	307,245	604,927	5,099	118.6	117.7	600,046	(4,881)	(2,402)	(2,479)	-$910
45		*Summer*	June	207,272	(24)	207,248	4,953	41.8	59.4	294,140	86,892	86,892		$16,205
46		*$0.1865*	July	116,133	0	116,133	4,905	23.7	16.5	80,797	(35,336)	(35,336)		-$6,590
47		*Winter*	August	99,054	88	99,142	4,924	20.1	11.7	57,787	(41,355)	(41,355)		-$7,713
48		*$0.1865*	September	156,660	0	156,660	4,941	31.7	23.0	113,863	(42,797)	(42,797)		-$7,982
49			October	229,293	(27)	229,266	4,986	46.0	64.2	319,906	90,641	90,641		$16,904
50			November	371,818	331,258	703,076	5,026	139.9	141.1	709,174	6,098	3,225	2,873	$1,137
51			December	(53)	1,360,353	1,360,300	5,234	259.9	287.2	1,503,339	143,039		143,039	$26,677
52				1,477,924	7,966,938	9,444,862		1,847.7	2,078.7	10,630,049	1,185,187	58,867	1,126,319	$221,037
53	G-50/T-50	Low Annual, Low Winter	January	0	162,592	162,592	812	200.3	200.3	162,592	0		-	$0
54			February	0	163,761	163,761	825	198.5	198.5	163,761	0		-	$0
55		*Rates*	March	0	156,891	156,891	826	190.1	190.1	156,891	0		-	$0
56		*Customer*	April	8	98,889	98,897	828	119.5	119.5	98,897	0		-	$0
57		*$75.09*	May	46,723	44,759	91,482	833	109.8	109.8	91,482	0	-	-	$0
58		*Summer*	June	100,996	0	100,996	844	119.6	119.6	100,996	0	-		$0
59		*$0.1865*	July	110,175	0	110,175	857	128.6	128.6	110,175	0	-		$0
60		*Winter*	August	106,021	0	106,021	848	125.0	125.0	106,021	0	-		$0
61		*$0.1865*	September	126,540	0	126,540	848	149.3	149.3	126,540	0	-		$0
62			October	100,562	(48)	100,514	816	123.1	123.1	100,514	0	-		$0
63			November	65,069	49,618	114,688	821	139.8	139.8	114,688	0	-	-	$0
64			December	0	141,206	141,206	831	169.8	169.8	141,206	0		-	$0
65				656,093	817,670	1,473,763		1,773.5	1,773.5	1,473,763	0	0	0	$0
66	G-41/T-41	Med. Annual, High Winter	January	11,142	2,457,584	2,468,726	742	3,326	3,610	2,679,813	211,087		211,087	$51,189
67			February	0	2,407,737	2,407,737	739	3,258	3,694	2,730,344	322,606		322,606	$78,232
68		*Rates*	March	0	2,077,387	2,077,387	736	2,821	3,141	2,312,568	235,182		235,182	$57,032
69		*Customer*	April	1,824	1,333,734	1,335,559	736	1,814	2,034	1,497,721	162,162		162,162	$39,324
70		*$222.64*	May	479,198	448,673	927,870	735	1,263	1,217	894,001	(33,869)	(17,492)	(16,378)	-$7,286
71		*Summer*	June	401,386	0	401,386	729	551	716	521,704	120,318	120,318		$22,800
72		*$0.1895*	July	259,893	0	259,893	726	358	332	241,016	(18,876)	(18,876)		-$3,577
73		*Winter*	August	151,231	0	151,231	721	210	280	201,676	50,445	50,445		$9,559
74		*$0.2425*	September	319,271	(2,303)	316,968	722	439	397	286,497	(30,471)	(30,471)		-$5,774
75			October	490,403	1,490	491,893	723	680	735	531,558	39,664	39,664		$7,516
76			November	513,191	576,140	1,089,331	728	1,497	1,570	1,142,289	52,958	24,949	28,009	$11,520
77			December	0	1,820,964	1,820,964	704	2,586	2,756	1,940,963	119,999		119,999	$29,100
78				2,627,539	11,121,406	13,748,945		18,802	20,482	14,980,151	1,231,206	168,537	1,062,669	$289,635

Northern Utilities New Hampshire
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[A]	[B]	[C]	[D]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]
				Customer Annualization					Rate Change	Pro Forma Adjustment	
Line	Rate Class	Description	Month	Year-End Customer Adjustment	Annualization Therm Adjustment	Annualization Therm Adj. Summer	Annualization Therm Adj. Winter	Annualization Revenue Adjustment	R-10 Rate Change Annualization	Total Therm Adjustment	Test Year Revenue Adjustment
				[H]Dec - [H]	[J] x [P]	[J] x [P]	[J] x [P]	[P]xRt+[R]xRt+[S]xRt	[E]xDif+[H]xDif	[L] + [Q]	[U]+[O]+[T]
40	G-40/T-40	Low Annual, High Winter	January	108	42,970		42,970	$16,156		273,865	$59,218
41			February	110	44,986		44,986	$16,670		374,285	$78,084
42		*Rates*	March	106	35,861		35,861	$14,670		294,103	$62,832
43		*Customer*	April	154	33,268		33,268	$17,750		197,719	$48,420
44		*$75.09*	May	135	15,869	7,809	8,060	$13,087		10,988	$12,176
45		*Summer*	June	282	16,732	16,732		$24,276		103,624	$40,481
46		*$0.1865*	July	329	5,421	5,421		$25,723		(29,915)	$19,133
47		*Winter*	August	310	3,640	3,640		$23,972		(37,715)	$16,259
48		*$0.1865*	September	293	6,763	6,763		$23,298		(36,034)	$15,316
49			October	248	15,906	15,906		$21,584		106,547	$38,488
50			November	208	29,367	15,530	13,836	$21,106		35,465	$22,243
51			December	0	-		-	$0		143,039	$26,677
52				2,284	250,784	71,802	178,982	$218,291		1,435,971	$439,328
53	G-50/T-50	Low Annual, Low Winter	January	20	3,975		3,975	$2,231		3,975	$2,231
54			February	6	1,277		1,277	$721		1,277	$721
55		*Rates*	March	6	1,134		1,134	$660		1,134	$660
56		*Customer*	April	4	438		438	$357		438	$357
57		*$75.09*	May	(2)	(172)	(172)		-$150		(172)	-$150
58		*Summer*	June	(13)	(1,512)	(1,512)		-$1,231		(1,512)	-$1,231
59		*$0.1865*	July	(25)	(3,224)	(3,224)		-$2,484		(3,224)	-$2,484
60		*Winter*	August	(17)	(2,079)	(2,079)		-$1,637		(2,079)	-$1,637
61		*$0.1865*	September	(16)	(2,428)	(2,428)		-$1,674		(2,428)	-$1,674
62			October	15	1,868	1,868		$1,488		1,868	$1,488
63			November	11	1,533		1,533	$1,109		1,533	$1,109
64			December	0	-		-	$0		-	$0
65				(10)	810	(7,547)	8,357	-$609		810	-$609
66	G-41/T-41	Med. Annual, High Winter	January	(38)	(137,312)		(137,312)	-$41,766		73,775	$9,423
67			February	(35)	(128,568)		(128,568)	-$38,926		194,039	$39,307
68		*Rates*	March	(32)	(100,815)		(100,815)	-$31,594		134,367	$25,437
69		*Customer*	April	(32)	(65,520)		(65,520)	-$23,061		96,642	$16,263
70		*$222.64*	May	(30)	(36,883)	(36,883)		-$13,736		(70,753)	-$21,023
71		*Summer*	June	(25)	(17,678)	(17,678)		-$8,849		102,640	$13,951
72		*$0.1895*	July	(21)	(7,108)	(7,108)		-$6,111		(25,984)	-$9,689
73		*Winter*	August	(17)	(4,781)	(4,781)		-$4,713		45,664	$4,846
74		*$0.2425*	September	(17)	(6,869)	(6,869)		-$5,153		(37,340)	-$10,928
75			October	(19)	(13,797)	(13,797)		-$6,793		25,867	$724
76			November	(24)	(36,988)		(36,988)	-$14,216		15,970	-$2,696
77			December	0	-		-	$0		119,999	$29,100
78				(290)	(556,319)	(87,117)	(469,203)	-$194,920		674,887	$94,715

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[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]
				Per Books					Weather Normalization					
												WN Therm Adjustment	WN Therm Adjustment	
Line	Rate Class	Description	Month	2020 Therms - Summer	2020 Therms - Winter	2020 Therms - Total	2020 Customers	2020 UPC	Normal UPC	2020 Normal Therms	WN Therm Adjustment	Summer	Winter	WN Revenue Adjustment
								[G] / [H]	WNA	[H] x [J]	[K] - [G]	[K] - [G]	[K] - [G]	[M] x Rate + [N] x Rate
79	G-51/T-51	Med. Annual, Low Winter	January	404	573,932	574,336	279	2,057	2,040	569,637	(4,699)		(4,699)	-$657
80			February	0	564,038	564,038	277	2,035	2,076	575,391	11,353		11,353	$1,588
81		*Rates*	March	0	535,718	535,718	278	1,927	1,928	536,049	331		331	$46
82		*Customer*	April	359	307,104	307,462	278	1,106	1,485	412,752	105,290		105,290	$14,730
83		*$222.64*	May	138,093	137,155	275,248	278	989	1,336	371,675	96,428	48,378	48,050	$11,981
84		*Summer*	June	266,334	(3,946)	262,387	277	948	1,267	350,616	88,229	88,229		$9,590
85		*$0.1337*	July	272,663	0	272,663	277	986	1,133	313,453	40,790	40,790		$4,434
86		*$0.1087*	August	256,063	0	256,063	274	934	1,059	290,228	34,165	34,165		$3,714
87			September	310,812	0	310,812	276	1,127	1,190	328,287	17,475	17,475		$1,900
88		*Winter*	October	299,345	411	299,755	279	1,073	1,147	320,330	20,575	20,575		$2,236
89		*$0.1712*	November	202,739	160,794	363,532	278	1,306	1,418	394,656	31,124	17,358	13,766	$3,813
90		*$0.1399*	December	0	447,486	447,486	267	1,679	1,787	476,284	28,798		28,798	$4,029
91				1,746,810	2,722,691	4,469,501		16,168	17,866	4,939,359	469,858	266,970	202,888	$57,404
92	G-42/T-42	High Annual, High Winter	January	0	883,132	883,132	34	25,974	29,522	1,003,732	120,600		120,600	$23,927
93			February	0	842,264	842,264	35	24,065	26,436	925,261	82,997		82,997	$16,467
94		*Rates*	March	0	710,411	710,411	35	20,297	23,699	829,467	119,056		119,056	$23,621
95		*Customer*	April	14,062	516,408	530,470	35	15,156	16,620	581,698	51,228		51,228	$10,164
96		*$1,335.81*	May	302,173	38,889	341,062	35	9,607	10,463	371,433	30,370	26,907	3,463	$3,932
97		*Summer*	June	218,221	0	218,221	35	6,235	7,036	246,274	28,053	28,053		$3,383
98		*$0.1206*	July	184,562	0	184,562	35	5,273	6,112	213,906	29,344	29,344		$3,539
99		*Winter*	August	191,592	0	191,592	35	5,474	6,198	216,926	25,333	25,333		$3,055
100		*$0.1984*	September	243,881	0	243,881	34	7,173	7,488	254,575	10,694	10,694		$1,290
101			October	392,858	11,382	404,240	34	11,889	12,378	420,845	16,606	16,606		$2,003
102			November	42,102	531,834	573,936	34	16,880	18,657	634,352	60,416	4,432	55,984	$11,642
103			December	0	699,750	699,750	31	22,573	25,385	786,923	87,173		87,173	$17,295
104				1,589,451	4,234,069	5,823,520		170,598	189,993	6,485,392	661,872	141,371	520,501	$120,317
105	G-52/T-52	High Annual, Low Winter	January	0	1,285,855	1,285,855	32	40,393	40,393	1,285,855	0	-		$0
106			February	0	1,458,466	1,458,466	32	45,577	45,577	1,458,466	0	-		$0
107		*Rates*	March	0	1,334,531	1,334,531	32	41,704	41,704	1,334,531	0	-		$0
108		*Customer*	April	41,018	1,300,352	1,341,370	32	41,918	41,918	1,341,370	0	-		$0
109		*$1,335.81*	May	1,276,171	5,650	1,281,821	34	38,263	38,263	1,281,821	0	-	-	$0
110		*Summer*	June	1,261,218	12,462	1,273,681	34	37,461	37,461	1,273,681	0		-	$0
111		*$0.0792*	July	1,220,236	0	1,220,236	33	36,977	36,977	1,220,236	0		-	$0
112		*Winter*	August	1,282,733	0	1,282,733	33	38,871	38,871	1,282,733	0		-	$0
113		*$0.1720*	September	1,373,207	0	1,373,207	32	42,913	42,913	1,373,207	0		-	$0
114			October	1,344,057	43,229	1,387,286	32	43,353	43,353	1,387,286	0		-	$0
115			November	28,665	1,354,228	1,382,893	32	42,726	42,726	1,382,893	0	-	-	$0
116			December	0	1,562,138	1,562,138	33	47,338	47,338	1,562,138	0	-		$0
117				7,827,306	8,356,912	16,184,218		497,493	497,493	16,184,218	0	0	0	$0
118		**Total Test Year Adjustment**		**19,496,726**	**49,633,554**	**69,130,280**				**74,576,215**	**5,445,936**	**719,598**	**4,726,338**	**$1,994,374**

Northern Utilities New Hampshire
Weather Normalization and Customer Annualization

[A]	[B]	[C]	[D]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]
				Customer Annualization					Rate Change	Pro Forma Adjustment	
Line	Rate Class	Description	Month	Year-End Customer Adjustment	Annualization Therm Adjustment	Annualization Therm Adj. Summer	Annualization Therm Adj. Winter	Annualization Revenue Adjustment	R-10 Rate Change Annualization	Total Therm Adjustment	Test Year Revenue Adjustment
				[H]Dec - [H]	[J] x [P]	[J] x [P]	[J] x [P]	[P]xRt+[R]xRt+[S]xRt	[E]xDif+[H]xDif	[L] + [Q]	[U]+[O]+[T]
79	G-51/T-51	Med. Annual, Low Winter	January	(13)	(25,976)		(25,976)	-$6,987		(30,675)	-$7,645
80			February	(11)	(22,144)		(22,144)	-$5,907		(10,791)	-$4,318
81		*Rates*	March	(12)	(22,175)		(22,175)	-$6,131		(21,844)	-$6,084
82		*Customer*	April	(12)	(17,074)		(17,074)	-$5,417		88,215	$9,313
83		*$222.64*	May	(12)	(15,719)	(15,719)		-$4,623		80,709	$7,358
84		*Summer*	June	(10)	(12,884)	(12,884)		-$3,918		75,345	$5,672
85		*$0.1337*	July	(10)	(11,446)	(11,446)		-$3,745		29,344	$689
86		*$0.1087*	August	(8)	(8,116)	(8,116)		-$2,781		26,050	$933
87			September	(9)	(11,185)	(11,185)		-$3,544		6,290	-$1,644
88		*Winter*	October	(13)	(14,607)	(14,607)		-$4,741		5,967	-$2,505
89		*$0.1712*	November	(12)	(16,734)		(16,734)	-$5,448		14,391	-$1,636
90		*$0.1399*	December	0	-		-	$0		28,798	$4,029
91				(120)	(178,059)	(73,956)	(104,102)	-$53,242		291,799	$4,162
92	G-42/T-42	High Annual, High Winter	January	(3)	(88,565)		(88,565)	-$21,579		32,036	$2,348
93			February	(4)	(105,744)		(105,744)	-$26,323		(22,747)	-$9,856
94		*Rates*	March	(4)	(94,796)		(94,796)	-$24,151		24,260	-$530
95		*Customer*	April	(4)	(66,480)		(66,480)	-$18,533		(15,252)	-$8,369
96		*$1,335.81*	May	(4)	(47,083)	(47,083)		-$11,689		(16,713)	-$7,757
97		*Summer*	June	(4)	(28,146)	(28,146)		-$8,738		(92)	-$5,354
98		*$0.1206*	July	(4)	(24,446)	(24,446)		-$8,291		4,898	-$4,753
99		*Winter*	August	(4)	(24,792)	(24,792)		-$8,333		542	-$5,278
100		*$0.1984*	September	(3)	(22,463)	(22,463)		-$6,716		(11,768)	-$5,427
101			October	(3)	(37,133)	(37,133)		-$8,486		(20,527)	-$6,483
102			November	(3)	(55,973)		(55,973)	-$15,112		4,443	-$3,471
103			December	0	-		-	$0		87,173	$17,295
104				(41)	(595,620)	(184,063)	(411,557)	-$157,951		66,252	-$37,635
105	G-52/T-52	High Annual, Low Winter	January	1	47,125		47,125	$9,664		47,125	$9,664
106			February	1	45,577		45,577	$9,175		45,577	$9,175
107		*Rates*	March	1	41,704		41,704	$8,509		41,704	$8,509
108		*Customer*	April	1	41,917		41,917	$8,546		41,917	$8,546
109		*$1,335.81*	May	(1)	(19,132)	(19,132)		-$2,183		(19,132)	-$2,183
110		*Summer*	June	(1)	(37,461)	(37,461)		-$4,303		(37,461)	-$4,303
111		*$0.0792*	July	0	-	-		$0		-	$0
112		*Winter*	August	0	-	-		$0		-	$0
113		*$0.1720*	September	1	42,913	42,913		$4,734		42,913	$4,734
114			October	1	43,353	43,353		$4,769		43,353	$4,769
115			November	1	27,060		27,060	$5,500		27,060	$5,500
116			December	0	-		-	$0		-	$0
117				5	233,056	29,672	203,384	$44,412		233,056	$44,412
118		**Total Test Year Adjustment**		**7,942**	**(424,106)**	**(192,862)**	**(231,244)**	**$278,301**	**$265,302**	**5,021,830**	**$2,537,977**

Northern Utilities New Hampshire
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Design Day with Customer Component of Mains
Functionalization

Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
1	**RATE BASE**							
2	**Plant in Service**							
3	**Intangible Plant**							
4	Miscellaneous Intangible Plant, Plant-related	303	212,619	INT_PLANT	1,424	123,191	88,003	-
5	Miscellaneous Intangible Plant, Customer-related	303	9,041,497	DISTRIBUTION	-	9,041,497	-	-
6	Miscellaneous Intangible Plant, Labor-related	303	3,572,231	INT_LABOR	160,985	1,044,144	1,614,481	752,621
7	Subtotal - Intangible Plant		12,826,347		162,409	10,208,833	1,702,484	752,621
8	**Mfg. Gas Produc. Plant**							
9	Land and Land Rights	304	2,787	PROD_OH	2,787	-	-	-
10	Structures & Improvements	305	-	-	-	-	-	-
11	Other Equipment	320	-	-	-	-	-	-
12	LNG Equipment	321	-	-	-	-	-	-
13	Subtotal - Mfg. Gas Produc. Plant		2,787		2,787	-	-	-
14	**Other Storage Plant**							
15	Land - Lewiston	360	23,833	PROD_OH	23,833	-	-	-
16	Structures & Improvements	361	232,281	PROD_OH	232,281	-	-	-
17	Gas Holders	362	1,585,468	PROD_OH	1,585,468	-	-	-
18	Other Equipment	363	35,693	PROD_OH	35,693	-	-	-
19	Subtotal - Other Storage Plant		1,877,275		1,877,275	-	-	-
20	**Distribution Plant**							
21	Land & Land Rights, Other Distr Sys	374.4	89,111	DISTRIBUTION	-	89,111	-	-
22	Land & Land Rights, Right of Way	374.5	17,911	DISTRIBUTION	-	17,911	-	-
23	Structures & Improvements	375	3,260,871	DISTRIBUTION	-	3,260,871	-	-
24	Mains	376	151,932,588	DISTRIBUTION	-	151,932,588	-	-
25	M&R Station Equip. - Regulating	378	7,288,982	DISTRIBUTION	-	7,288,982	-	-
26	M&R Station Equip. - G	379	39,266	DISTRIBUTION	-	39,266	-	-
27	Services	380	82,837,047	ONSITE	-	-	82,837,047	-
28	Meters	381	4,624,610	ONSITE	-	-	4,624,610	-
29	Meter Installations	382	26,001,685	ONSITE	-	-	26,001,685	-
30	House Regulators	383	733,550	ONSITE	-	-	733,550	-
31	Water Heaters/Conversion Burners	386	1,978,895	ONSITE	-	-	1,978,895	-
32	Subtotal - Distribution Plant		278,804,516			162,628,729	116,175,787	-
33	**General Plant**							
34	Land and Land Rights	389	232,947	INT_PLANT	1,560	134,969	96,417	-
35	Office Furniture & Equipment	391	508,135	INT_LABOR	22,899	148,525	229,653	107,057
36	Stores Equipment	393	31,520	INT_PLANT	211	18,263	13,046	-
37	Tools, Shop & Garage Equip.	394	1,430,421	INT_PLANT	9,581	828,787	592,054	-
38	Power Operated Equip.	396	75,266	INT_PLANT	504	43,609	31,153	-
39	Communication Equip.	397	1,873,480	INT_PLANT	12,549	1,085,495	775,436	-
40	Metscan Communication Equip	397.25	112,656	ONSITE	-	-	112,656	-
41	ERT Automatic Reading Dev	397.35	3,470,146	ONSITE	-	-	3,470,146	-
42	Subtotal - General Plant		7,734,572		47,305	2,259,648	5,320,562	107,057
43	**Total Plant in Service**		301,245,498		2,089,776	175,097,210	123,198,833	859,678

Northern Utilities New Hampshire
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Design Day with Customer Component of Mains
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Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
44	**Accumulated Depreciation**							
45	**Intangible Plant**							
46	Miscellaneous Intangible Plant, Plant-related	303	(81,184)	INT_PLANT	(544)	(47,038)	(33,602)	-
47	Miscellaneous Intangible Plant, Customer-related	303	(3,452,299)	DISTRIBUTION	-	(3,452,299)	-	-
48	Miscellaneous Intangible Plant, Labor-related	303	(1,363,979)	INT_LABOR	(61,469)	(398,684)	(616,454)	(287,372)
49	Subtotal - Intangible Plant		(4,897,461)		(62,012)	(3,898,020)	(650,057)	(287,372)
50	**Mfg. Gas Produc. Plant**							
51	Land and Land Rights	304	-	-	-	-	-	-
52	Structures & Improvements	305	374	PROD_OH	374	-	-	-
53	Other Equipment	320	4,438	PROD_OH	4,438	-	-	-
54	LNG Equipment	321	27,544	PROD_OH	27,544	-	-	-
55	Subtotal - Mfg. Gas Produc. Plant		32,357		32,357	-	-	-
56	**Other Storage Plant**							
57	Land - Lewiston	360	-	-	-	-	-	-
58	Structures & Improvements	361	(109,222)	PROD_OH	(109,222)	-	-	-
59	Gas Holders	362	(1,203,365)	PROD_OH	(1,203,365)	-	-	-
60	Other Equipment	363	(37,603)	PROD_OH	(37,603)	-	-	-
61	Subtotal - Other Storage Plant		(1,350,190)		(1,350,190)	-	-	-
62	**Distribution Plant**							
63	Land & Land Rights, Other Distr Sys	374.4	-	-	-	-	-	-
64	Land & Land Rights, Right of Way	374.5	-	-	-	-	-	-
65	Structures & Improvements	375	(596,162)	DISTRIBUTION	-	(596,162)	-	-
66	Mains	376	(38,511,660)	DISTRIBUTION	-	(38,511,660)	-	-
67	M&R Station Equip. - Regulating	378	(666,376)	DISTRIBUTION	-	(666,376)	-	-
68	M&R Station Equip. - G	379	(6,432)	DISTRIBUTION	-	(6,432)	-	-
69	Services	380	(28,479,497)	ONSITE	-	-	(28,479,497)	-
70	Meters	381	(1,226,613)	ONSITE	-	-	(1,226,613)	-
71	Meter Installations	382	(6,859,297)	ONSITE	-	-	(6,859,297)	-
72	House Regulators	383	(212,402)	ONSITE	-	-	(212,402)	-
73	Water Heaters/Conversion Burners	386	(959,565)	ONSITE	-	-	(959,565)	-
74	Subtotal - Distribution Plant		(77,518,004)		-	(39,780,631)	(37,737,373)	-
75	**General Plant**							
76	Land & Land Rights	389	-	-	-	-	-	-
77	Office Furniture & Equipment	391	(298,078)	INT_LABOR	(13,433)	(87,127)	(134,717)	(62,801)
78	Stores Equipment	393	(31,511)	INT_PLANT	(211)	(18,258)	(13,042)	-
79	Tools, Shop & Garage Equip.	394	(785,741)	INT_PLANT	(5,263)	(455,259)	(325,220)	-
80	Power Operated Equip.	396	(75,266)	INT_PLANT	(504)	(43,609)	(31,153)	-
81	Communication Equip.	397	(1,570,602)	INT_PLANT	(10,520)	(910,007)	(650,074)	-
82	Metscan Communication Equip	397.25	(112,656)	ONSITE	-	-	(112,656)	-
83	ERT Automatic Reading Dev	397.35	(2,766,299)	ONSITE	-	-	(2,766,299)	-
84	Subtotal - General Plant		(5,640,154)		(29,931)	(1,514,260)	(4,033,162)	(62,801)
85	**Total Accumulated Depreciation**		(89,373,452)		(1,409,777)	(45,192,910)	(42,420,592)	(350,173)

Northern Utilities New Hampshire
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Functionalization

Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
86	**Other Rate Base Items**							
87	Material and Supplies	154	2,773,457	INT_DIST_PLANT	-	1,617,778	1,155,679	-
88	Prepayments	165	64,895	INT_DIST_PLANT	-	37,854	27,041	-
89	Cash Working Capital	131	1,773,194	INT_TOTAL_PLANT	12,301	1,030,659	725,174	5,060
90	Cash Working Capital - Pro Forma	131	235,191	INT_TOTAL_PLANT	1,632	136,703	96,185	671
91	Customer Deposits	235	(249,677)	ACCTS_SERVICES	-	-	-	(249,677)
92	Net Deferred Income Taxes	283	(21,177,756)	INT_TOTAL_PLANT	(146,913)	(12,309,449)	(8,660,959)	(60,436)
93	Excess Deferred Income Taxes - Regulatory Liability	254	(8,999,336)	INT_TOTAL_PLANT	(62,429)	(5,230,812)	(3,680,412)	(25,682)
94	Excess Deferred Income Taxes - Gross up	283	2,427,244	INT_TOTAL_PLANT	16,838	1,410,821	992,657	6,927
95	Total Other Rate Base Items		(23,152,788)		(178,572)	(13,306,445)	(9,344,634)	(323,137)
96	**TOTAL RATE BASE**		188,719,257		501,428	116,597,855	71,433,607	186,368
97	**OPERATION AND MAINTENANCE EXPENSE**							
98	**Production, Storage, and Distribution Expense**							
99	**Mfg. Gas Produc. Plant**							
100	Supervision	710	12,038	PROD_OH	12,038	-	-	-
101	Propane Expenses	717	9,904	PROD_OH	9,904	-	-	-
102	Misc. Intangible Plant	735	24,360	PROD_OH	24,360	-	-	-
103	Subtotal - Mfg. Gas Produc. Plant		46,302		46,302	-	-	-
104	**Maintenance Expenses**							
105	Supervision	740	12,038	PROD_OH	12,038	-	-	-
106	Maintenance of Plant	741	3,460	PROD_OH	3,460	-	-	-
107	Maintenance of Equipment	742	11,687	PROD_OH	11,687	-	-	-
108	Maint of Scada - Production	769	2,704	PROD_OH	2,704	-	-	-
109	Subtotal - Maintenance Expenses		29,889		29,889	-	-	-
110	**Other Gas Expenses**							
111	Other Gas Supply Exp	813	290,076	PROD_OH	290,076	-	-	-
112	Other Gas Supp Exp - Del Serv	813	180,290	DISTRIBUTION	-	180,290	-	-
113	Subtotal - Other Gas Expenses		470,367		290,076	180,290	-	-
114	**Operation Expenses**							
115	System Cntl/Load Dispatching	851.02	2,885	DISTRIBUTION	-	2,885	-	-
116	System Cntl/Load Dispatching - Gas Supply	851.0201	-	-	-	-	-	-
117	Communication System Exp	852	62,100	DISTRIBUTION	-	62,100	-	-
118	Subtotal - Operation Expenses		64,985		-	64,985	-	-

Northern Utilities New Hampshire
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Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
119	**Distribution Operation Expenses**							
120	Op Superv-Eng-Gas Distr	870	39,588	INT_874-879	-	14,895	24,694	-
121	Mains & Services	874	793,237	INT_MAIN_SVCS	-	513,348	279,889	-
122	Regulator Station Expense	875	320,571	DISTRIBUTION	-	320,571	-	-
123	Meter & House Regulator	878	1,054,382	ONSITE	-	-	1,054,382	-
124	Customer Installation Exp	879	48,280	ONSITE	-	-	48,280	-
125	Operations Exp Other	880	1,139,382	INT_874-879	-	428,678	710,704	-
126	Subtotal - Distribution Operation Expenses		3,395,440		-	1,277,492	2,117,948	-
127	**Distribution Maintenance Expenses**							
128	Maint Supvervision	885	90,410	INT_887-894	-	39,513	50,897	-
129	Structures & Improvements	886	35,514	INT_887-894	-	15,521	19,993	-
130	Mains	887	81,512	DISTRIBUTION	-	81,512	-	-
131	Measuring & Regulating - Atatew EQ	889	64,637	DISTRIBUTION	-	64,637	-	-
132	Measuring & Regulating - EQ Industry	890	5,322	DISTRIBUTION	-	5,322	-	-
133	Measuring & Regulating - EQ City Gate	891	45,328	DISTRIBUTION	-	45,328	-	-
134	Main Distri SCADA	891.01	40,137	DISTRIBUTION	-	40,137	-	-
135	Services	892	142,056	ONSITE	-	-	142,056	-
136	Meters & House Regulators	893	26,058	ONSITE	-	-	26,058	-
137	Other Equipment	894	1,035	INT_887-894	-	452	582	-
138	Water Heaters & Conv Burn	894.01	137,082	ONSITE	-	-	137,082	-
139	Rented Conv Burn		-	-	-	-	-	-
140	Subtotal - Distribution Maintenance Expenses		669,090		-	292,422	376,668	-
141	**Total Production, Storage, and Distribution Expense**		4,676,073		366,267	1,815,190	2,494,616	-
142	**Customer Accounts, Service, and Sales Expense**							
143	**Customer Accounts Expense**							
144	Meter Reading Expense	902	202,880	ACCTS_SERVICES	-	-	-	202,880
145	Cust Records and Col	903	2,052,586	ACCTS_SERVICES	-	-	-	2,052,586
146	Uncollectible Accts	904	437,750	ACCTS_SERVICES	-	-	-	437,750
147	Subtotal - Customer Accounts Expense		2,693,217		-	-	-	2,693,217
148	**Customer Service & Information Expense**							
149	Customer Assistance - other	908	-	-	-	-	-	-
150	Inf and Instruct Expense	909	73,965	ACCTS_SERVICES	-	-	-	73,965
151	Subtotal - Customer Service & Information Expense		73,965		-	-	-	73,965
152	**Sales Expense**							
153	Advertising Expense	913	70,021	ACCTS_SERVICES	-	-	-	70,021
154	Interest on Customer Deposits		9,371	ACCTS_SERVICES	-	-	-	9,371
155	Subtotal - Sales Expense		79,392		-	-	-	79,392
156	**Total Customer Accounts, Service, and Sales Expense**		2,846,573		-	-	-	2,846,573

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Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
157	**Administrative and General Expense**							
158	Administrative and General Salaries	920	11,414	INT_LABOR	514	3,336	5,158	2,405
159	Office Supplies and Exp	921	425,018	INT_LABOR	19,154	124,230	192,088	89,546
160	Outside Service Employed	923	3,909,556	INT_LABOR	176,187	1,142,742	1,766,936	823,691
161	Property Insurance	924	2,931	INT_PLANT	20	1,698	1,213	-
162	Injuries and Damages	925	293,510	INT_LABOR	13,227	85,792	132,653	61,839
163	Employee Pension and Benefits	926	2,201,576	INT_LABOR	99,216	643,509	995,009	463,842
164	Regulatory Commission Exp	928	504,386	INT_RATEBASE	1,340	311,629	190,919	498
165	General Advertising Expense	930	42,897	INT_LABOR	1,933	12,539	19,387	9,038
166	Rents Admin and General	931	23,527	INT_LABOR	1,060	6,877	10,633	4,957
167	Maint General Plant - Equip Shared	932	130,652	INT_GEN_PLANT	799	38,170	89,875	1,808
168	Maint of General Plant	935	6,985	INT_GEN_PLANT	43	2,041	4,805	97
169	Subtotal - Administrative and General Expense		7,552,453		313,493	2,372,562	3,408,678	1,457,720
170	**Total Administrative and General Expense**		7,552,453		313,493	2,372,562	3,408,678	1,457,720
171	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		15,075,099		679,760	4,187,752	5,903,294	4,304,293
172	**Depreciation and Amortization Expense**							
173	**Intangible Plant**							
174	Miscellaneous Intangible Plant, Plant-related	303	-	-	-	-	-	-
175	Miscellaneous Intangible Plant, Customer-related	303	-	-	-	-	-	-
176	Miscellaneous Intangible Plant, Labor-related	303	-	-	-	-	-	-
177	Subtotal - Intangible Plant		-		-	-	-	-
178	**Mfg. Gas Produc. Plant**							
179	Land and Land Rights	304	-	-	-	-	-	-
180	Structures & Improvements	305	931	PROD_OH	931	-	-	-
181	Other Equipment	320	-	-	-	-	-	-
182	LNG Equipment	321	-	-	-	-	-	-
183	Subtotal - Mfg. Gas Produc. Plant		931		931	-	-	-
184	**Other Storage Plant**							
185	Land - Lewiston	360	-	-	-	-	-	-
186	Structures & Improvements	361	4,785	PROD_OH	4,785	-	-	-
187	Gas Holders	362	32,149	PROD_OH	32,149	-	-	-
188	Other Equipment	363	-	-	-	-	-	-
189	Subtotal - Other Storage Plant		36,934		36,934	-	-	-

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Design Day with Customer Component of Mains
Functionalization

Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
190	**Distribution Plant**							
191	Land & Land Rights, Other Distr Sys	374.4	-	-	-	-	-	-
192	Land & Land Rights, Right of Way	374.5	-	-	-	-	-	-
193	Structures & Improvements	375	89,348	DISTRIBUTION	-	89,348	-	-
194	Mains	376	5,348,398	DISTRIBUTION	-	5,348,398	-	-
195	M&R Station Equip. - Regulating	378	354,973	DISTRIBUTION	-	354,973	-	-
196	M&R Station Equip. - G	379	1,912	DISTRIBUTION	-	1,912	-	-
197	Services	380	3,653,114	ONSITE	-	-	3,653,114	-
198	Meters	381	246,954	ONSITE	-	-	246,954	-
199	Meter Installations	382	1,099,871	ONSITE	-	-	1,099,871	-
200	House Regulators	383	24,354	ONSITE	-	-	24,354	-
201	Water Heaters/Conversion Burners	386	224,802	ONSITE	-	-	224,802	-
202	Subtotal - Distribution Plant		11,043,726		-	5,794,631	5,249,095	-
203	**General Plant**							
204	Land & Land Rights	389	-	-	-	-	-	-
205	Office Furniture & Equipment	391	30,265	INT_LABOR	1,364	8,846	13,678	6,376
206	Stores Equipment	393	-	-	-	-	-	-
207	Tools, Shop & Garage Equip.	394	25,364	INT_PLANT	170	14,696	10,498	-
208	Power Operated Equip.	396	-	-	-	-	-	-
209	Communication Equip.	397	19,827	INT_PLANT	133	11,488	8,206	-
210	Metscan Communication Equip	397.25	-	-	-	-	-	-
211	ERT Automatic Reading Dev	397.35	74,391	ONSITE	-	-	74,391	-
212	Subtotal - General Plant		149,847		1,667	35,030	106,774	6,376
213	**Amortization Expense**							
214	Amortization Expense	404	816,977	INT_INTANGIBLE	10,345	650,254	108,440	47,938
215	Amortization Expense Adjustments	404	189,288	INT_INTANGIBLE	2,397	150,659	25,125	11,107
216	Amortization Rate Case Costs - NH	407	-	-	-	-	-	-
217	Excess ADIT Flow Back	407	(308,218)	INT_RATEBASE	(819)	(190,429)	(116,666)	(304)
218	Subtotal - Amortization Expense		698,046		11,923	610,484	16,899	58,741
219	**Total Depreciation and Amortization Expense**		11,929,484		51,454	6,440,145	5,372,768	65,117
220	**Taxes**							
221	**Taxes Other Than Income**							
222	Payroll Taxes - FICA	408	224,247	INT_LABOR	10,106	65,546	101,349	47,246
223	Payroll Tax Pro Formas	408	137,672	INT_LABOR	6,204	40,241	62,221	29,006
224	Unemployment Tax - Federal	408.04	1,639	INT_LABOR	74	479	741	345
225	Unemployment Tax - State	408.06	1,135	INT_LABOR	51	332	513	239
226	Property Taxes	408.12	4,728,576	INT_TOTAL_PLANT	32,803	2,748,458	1,933,822	13,494
227	Property Taxes Pro Forma	408.12	617,939	INT_TOTAL_PLANT	4,287	359,173	252,715	1,763
228	Payroll Taxes Capitalized	408.1	(161,795)	INT_LABOR	(7,291)	(47,292)	(73,124)	(34,088)
229	Other Taxes	408.02	73,972	INT_RATEBASE	197	45,703	28,000	73
230	Subtotal - Taxes Other Than Income		5,623,385		46,430	3,212,640	2,306,237	58,079

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Functionalization

Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
231	**Income Taxes**							
232	Federal Income Tax	409.01	(485,546)	INT_RATEBASE	(1,290)	(299,989)	(183,788)	(479)
233	State Income Tax	409.02	(1,380,631)	INT_RATEBASE	(3,668)	(853,006)	(522,593)	(1,363)
234	Deferred Federal & State Income Taxes	410.01	3,492,441	INT_RATEBASE	9,279	2,157,761	1,321,951	3,449
235	Subtotal - Income Taxes		1,626,264		4,321	1,004,767	615,570	1,606
236	**Total Taxes**		7,249,649		50,751	4,217,407	2,921,807	59,685
237	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**							
238	**Test Year Expenses at Current Rates**		34,254,233	n/a	781,965	14,845,304	14,197,869	4,429,095
239	**Return on Rate Base**		14,621,110	INT_RATEBASE	38,848	9,033,472	5,534,351	14,439
240	**Gross Up Items**							
241	Tax1		2,107,856	INT_RATEBASE	5,601	1,302,313	797,861	2,082
242	ITem2		-	-	-	-	-	-
243	ITem3		-	-	-	-	-	-
244	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**50,983,199**		**826,413**	**25,181,089**	**20,530,081**	**4,445,616**
245	**INTERNAL ALLOCATION FACTORS**							
246	INT_PLANT		280,684,578		1,880,062	162,628,729	116,175,787	0
247	INT_INTANGIBLE		12,826,347		162,409	10,208,833	1,702,484	752,621
248	INT_MAIN_SVCS		234,769,635		0	151,932,588	82,837,047	0
249	INT_887-894		542,132		0	236,936	305,196	0
250	INT_RATEBASE		188,719,257		501,428	116,597,855	71,433,607	186,368
251	INT_REVREQ		48,875,343		820,813	23,878,776	19,732,220	4,443,534
252	INT_LABOR		4,695,390		211,601	1,372,437	2,122,097	989,255
253	INT_TOTAL_PLANT		301,245,498		2,089,776	175,097,210	123,198,833	859,678
254	INT_874-879		2,216,470		0	833,919	1,382,551	0
255	INT_DIST_PLANT		278,804,516		0	162,628,729	116,175,787	0
256	INT_GEN_PLANT		7,734,572		47,305	2,259,648	5,320,562	107,057

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Functionalization

Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
257	**INDIRECT PRODUCTION AND OVERHEAD SUMMARY**							
258	**LNG Production and Storage**							
259	Return on Assets				38,848			
260	O&M Expenses				76,191			
261	Associated A&G and Overheads				99,499			
262	**Total Production and Storage**				214,538			
263	**Other A&G Expenses (Energy Contracts Charges and Overheads)**							
264	Other Gas Supply Expenses (Acct. 813)				290,076			
265	Associated A&G and Overheads				321,799			
266	Total Other A&G Expenses				611,875			
267	**Total Indirect Production and Overhead**				**826,413**			

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Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	Account Balance	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52
1	**Rate Base**									
2	Plant in Service	$ 301,245,498	$ 170,246,732	$ 6,593,386	$ 51,245,369	$ 6,225,067	$ 36,771,567	$ 7,493,599	$ 11,647,303	$ 11,022,474
3	Accumulated Reserve	(89,373,452)	(52,308,017)	(2,111,513)	(15,148,725)	(1,919,028)	(9,769,917)	(2,152,494)	(3,074,609)	(2,889,149)
4	Other Rate Base Items	(23,152,788)	(13,000,952)	(503,394)	(3,962,675)	(497,283)	(2,864,201)	(601,238)	(889,945)	(833,100)
5	**Total Rate Base**	$ 188,719,257	$ 104,937,763	$ 3,978,479	$ 32,133,969	$ 3,808,756	$ 24,137,449	$ 4,739,867	$ 7,682,750	$ 7,300,225
6	**Revenue at Current Rates**									
7	Rate Schedule Revenue	$ 39,796,841	$ 20,731,783	$ 493,626	$ 6,745,829	$ 1,024,226	$ 5,235,691	$ 1,396,947	$ 1,545,114	$ 2,623,624
8	Special Contracts	1,197,813	694,032	27,624	202,566	25,332	136,142	30,636	42,210	39,271
9	Indirect Production & OH Revenue	1,057,890	510,076	6,031	238,849	19,474	98,439	101,838	69,962	13,222
10	Late Payment Revenues	76,773	54,649	1,478	8,359	1,627	6,010	2,313	790	1,546
11	Miscellaneous Revenues	1,070,932	848,963	36,804	99,475	13,662	42,047	7,466	11,035	11,481
12	**Total Revenue at Current Rates**	$ 43,200,249	$ 22,839,504	$ 565,562	$ 7,295,080	$ 1,084,321	$ 5,518,329	$ 1,539,199	$ 1,669,111	$ 2,689,143
13	**Expenses at Current Rates**									
14	O&M and A&G Expenses	$ 15,075,099	$ 9,171,694	$ 380,169	$ 2,528,361	$ 335,891	$ 1,440,748	$ 417,071	$ 427,957	$ 373,208
15	Depreciation and Amortization Expense	11,929,484	6,938,809	281,543	2,013,209	253,539	1,348,390	283,695	415,282	395,017
16	Taxes Other Than Income	5,623,385	3,182,191	123,567	956,858	116,545	683,495	140,674	215,969	204,087
17	Income Taxes	1,626,264	903,494	34,220	276,965	32,798	208,445	40,901	66,375	63,067
18	**Total Expenses at Current Rates**	$ 34,254,233	$ 20,196,188	$ 819,499	$ 5,775,393	$ 738,772	$ 3,681,077	$ 882,340	$ 1,125,583	$ 1,035,380
19	**Operating Income at Current Rates**	$ 8,946,016	$ 2,643,315	$ (253,936)	$ 1,519,687	$ 345,548	$ 1,837,252	$ 656,859	$ 543,528	$ 1,653,763
20	**Current Rate of Return**	4.74%	2.52%	-6.38%	4.73%	9.07%	7.61%	13.86%	7.07%	22.65%
21	**Current Revenue at Equal Rates of Return**									
22	Current Rate of Return	4.74%	4.74%	4.74%	4.74%	4.74%	4.74%	4.74%	4.74%	4.74%
23	Operating Income at Current Rates - Equal ROR	$ 8,946,016	$ 4,974,452	$ 188,595	$ 1,523,273	$ 180,550	$ 1,144,208	$ 224,688	$ 364,192	$ 346,059
24	Income Taxes - Equal ROR	1,626,264	904,288	34,284	276,910	32,821	208,001	40,845	66,205	62,909
25	Other Expenses - Equal ROR	32,627,968	19,292,694	785,279	5,498,428	705,975	3,472,633	841,439	1,059,208	972,312
26	**Total Revenue @ Equal Rates of Return**	$ 43,200,249	$ 25,171,434	$ 1,008,158	$ 7,298,612	$ 919,346	$ 4,824,842	$ 1,106,972	$ 1,489,605	$ 1,381,280
27	**Current Class (Subsidies)/Excesses**	$ -	$ (2,331,931)	$ (442,595)	$ (3,532)	$ 164,975	$ 693,487	$ 432,227	$ 179,505	$ 1,307,863

Northern Utilities New Hampshire
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Design Day with Customer Component of Mains
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	Account Balance	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52
28	**Revenue Requirement at Equal Rates of Return**									
29	Required Return	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
30	**Required Operating Income**	$ 14,621,110	$ 8,130,101	$ 308,234	$ 2,489,594	$ 295,085	$ 1,870,060	$ 367,223	$ 595,225	$ 565,588
31	**Expenses at Required Return**									
32	O&M and A&G Expenses	$ 15,075,099	$ 9,171,694	$ 380,169	$ 2,528,361	$ 335,891	$ 1,440,748	$ 417,071	$ 427,957	$ 373,208
33	Depreciation and Amortization Expense	11,929,484	6,938,809	281,543	2,013,209	253,539	1,348,390	283,695	415,282	395,017
34	Taxes Other Than Income	5,623,385	3,182,191	123,567	956,858	116,545	683,495	140,674	215,969	204,087
35	Income Taxes	1,626,264	903,494	34,220	276,965	32,798	208,445	40,901	66,375	63,067
36	Gross Up - Income Taxes	2,107,856	1,171,049	44,354	358,983	42,510	270,172	53,013	86,030	81,744
36	Gross Up - Other Items	-	-	-	-	-	-	-	-	-
37	**Total Expenses at Required Return**	$ 36,362,089	$ 21,367,238	$ 863,853	$ 6,134,376	$ 781,283	$ 3,951,249	$ 935,354	$ 1,211,613	$ 1,117,124
38	**Total Revenue Requirement at Equal Rates of Return**	$ 50,983,199	$ 29,497,339	$ 1,172,087	$ 8,623,970	$ 1,076,368	$ 5,821,309	$ 1,302,577	$ 1,806,838	$ 1,682,712
39	Less Other Revenue	1,197,813	694,032	27,624	202,566	25,332	136,142	30,636	42,210	39,271
40	Less Indirect Production & OH Revenue	826,413	398,466	4,711	186,587	15,213	76,899	79,555	54,653	10,329
41	Less Current Miscellaneous Revenue	1,147,705	903,612	38,282	107,835	15,289	48,057	9,779	11,825	13,026
42	**Total Rate Revenue @ Equal Rates of Return**	$ 47,811,268	$ 27,501,228	$ 1,101,470	$ 8,126,982	$ 1,020,534	$ 5,560,210	$ 1,182,608	$ 1,698,150	$ 1,620,086
43	**Rate Revenue (Deficiency)/Surplus**	$ (8,014,427)	$ (6,769,445)	$ (607,844)	$ (1,381,153)	$ 3,692	$ (324,520)	$ 214,339	$ (153,035)	$ 1,003,538
44	**Total Base Revenue as Proposed**	$ 47,811,268	$ 25,996,394	$ 692,442	$ 7,764,703	$ 1,127,357	$ 6,026,477	$ 1,537,608	$ 1,778,485	$ 2,887,802
45	Special Contracts Revenue	1,197,813	694,032	27,624	202,566	25,332	136,142	30,636	42,210	39,271
46	Indirect Production & OH Revenue	826,413	398,466	4,711	186,587	15,213	76,899	79,555	54,653	10,329
47	Miscellaneous Revenue	1,147,705	903,612	38,282	107,835	15,289	48,057	9,779	11,825	13,026
48	**Total Revenue as Proposed**	$ 50,983,199	$ 27,992,505	$ 763,059	$ 8,261,691	$ 1,183,191	$ 6,287,576	$ 1,657,577	$ 1,887,173	$ 2,950,427
49	**Total Distribution Margin Increase as Proposed**	$ 8,014,427	$ 5,264,611	$ 198,816	$ 1,018,874	$ 103,131	$ 790,786	$ 140,661	$ 233,370	$ 264,177
50	Special Contracts Revenue Change	-	-	-	-	-	-	-	-	-
51	Indirect Production & OH Revenue	(231,477)	(111,610)	(1,320)	(52,263)	(4,261)	(21,539)	(22,283)	(15,308)	(2,893)
52	Miscellaneous Revenue Change	-	-	-	-	-	-	-	-	-
53	**Total Revenue Increase as Proposed**	$ 7,782,951	$ 5,153,001	$ 197,496	$ 966,612	$ 98,870	$ 769,247	$ 118,378	$ 218,062	$ 261,284
54	Precent Total Revenue Change	19.56%	24.86%	40.01%	14.33%	9.65%	14.69%	8.47%	14.11%	9.96%
55	**Operating Income at Proposed Rates**									
56	Income Prior to Taxes	$ 18,355,231	$ 8,699,811	$ (22,220)	$ 2,763,263	$ 477,216	$ 2,814,943	$ 816,138	$ 827,964	$ 1,978,115
57	Less Income Taxes	3,734,121	2,074,543	78,574	635,948	75,308	478,617	93,914	152,405	144,811
58	**Operating Income**	$ 14,621,110	$ 6,625,267	$ (100,794)	$ 2,127,315	$ 401,908	$ 2,336,327	$ 722,224	$ 675,560	$ 1,833,304
59	**Proposed Return**	7.75%	6.3%	-2.5%	6.6%	10.6%	9.7%	15.2%	8.8%	25.1%

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Proposed Revenue Apportionment

Proposed Class Revenues

		Total System	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52	Special Contracts	Indirect Production & OH	Miscellaneous Revenue
1	Current Revenues	$ 43,200,249	$ 20,731,783	$ 493,626	$ 6,745,829	$ 1,024,226	$ 5,235,691	$ 1,396,947	$ 1,545,114	$ 2,623,624	$ 1,197,813	$ 1,057,890	$ 1,147,705
2	% Increase		24.2%	40.3%	15.1%	10.1%	15.1%	10.1%	15.1%	10.1%			
3	Targeted Increase	$ 7,528,387	$ 5,010,047	$ 198,816	$ 1,018,874	$ 103,131	$ 790,786	$ 140,661	$ 233,370	$ 264,177	$ -	$ (231,477)	$ -
4	Targeted Revenue	$ 50,728,636	$ 25,741,830	$ 692,442	$ 7,764,703	$ 1,127,357	$ 6,026,477	$ 1,537,608	$ 1,778,485	$ 2,887,802	$ 1,197,813	$ 826,413	$ 1,147,705
5	Allocation of Delta	$ 254,564	$ 254,564										
6	Proposed Increase/ (Decrease)	$ 7,782,951	$ 5,264,611	$ 198,816	$ 1,018,874	$ 103,131	$ 790,786	$ 140,661	$ 233,370	$ 264,177	$ -	$ (231,477)	$ -
7	Proposed Revenue	$ 50,983,199	$ 25,996,394	$ 692,442	$ 7,764,703	$ 1,127,357	$ 6,026,477	$ 1,537,608	$ 1,778,485	$ 2,887,802	$ 1,197,813	$ 826,413	$ 1,147,705
8	Resulting Increase % (Dist Margin)	19.6%	25.4%	40.3%	15.1%	10.1%	15.1%	10.1%	15.1%	10.1%			
9	Resulting Increase % with Total Revenues	18.0%	25.4%	40.3%	15.1%	10.1%	15.1%	10.1%	15.1%	10.1%	0.0%	-21.9%	0.0%
10	Proposed Distribution Margin	$ 47,811,268	$ 25,996,394	$ 692,442	$ 7,764,703	$ 1,127,357	$ 6,026,477	$ 1,537,608	$ 1,778,485	$ 2,887,802			
11	Proposed Rate of Return	7.75%	6.31%	-2.53%	6.62%	10.55%	9.68%	15.24%	8.79%	25.11%			
12	Proposed Revenue to Cost Ratio		0.95	0.63	0.96	1.10	1.08	1.30	1.05	1.78			
13	Current Revenue to Cost Ratio		0.75	0.45	0.83	1.00	0.94	1.18	0.91	1.62			

		Total System
14	Rate Margin Increase	8,014,427
15	System Increase (Total Revenue)	18.55%
16	System Increase (Total Distribution Margin)	20.14%

		Total System	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52	Special Contracts	Indirect Production & OH	Miscellaneous Revenue
	Under Current Rates												
17	Current Revenues	$ 43,200,249	$ 20,731,783	$ 493,626	$ 6,745,829	$ 1,024,226	$ 5,235,691	$ 1,396,947	$ 1,545,114	$ 2,623,624	$ 1,197,813	$ 1,057,890	$ 1,147,705
18	Current Rate Of Return	4.74%	2.52%	-6.38%	4.73%	9.07%	7.61%	13.86%	7.07%	22.65%			
19	Current Relative Rate of Return	1.00	0.53	(1.35)	1.00	1.91	1.61	2.92	1.49	4.78			
20	Current Revenue to Cost Ratio		0.75	0.45	0.83	1.00	0.94	1.18	0.91	1.62			
21	**Scenario A - Equalized Rate of Return**												
22	Equalized Rate of Return	$ 50,983,199	$ 27,501,228	$ 1,101,470	$ 8,126,982	$ 1,020,534	$ 5,560,210	$ 1,182,608	$ 1,698,150	$ 1,620,086	$ 1,197,813	$ 826,413	$ 1,147,705
23	Equalized Rate of Return Increase		$ 6,769,445	$ 607,844	$ 1,381,153	$ (3,692)	$ 324,520	$ (214,339)	$ 153,035	$ (1,003,538)			
24	% Change on Dist Margin (Equalized Rate of Return)		32.7%	123.1%	20.5%	-0.4%	6.2%	-15.3%	9.9%	-38.3%			
25	% Change on Total Revenue (Equalized ROR)		32.7%	123.1%	20.5%	-0.4%	6.2%	-15.3%	9.9%	-38.3%	0.0%	0.0%	0.0%
26	**Scenario B - Proportionate to Distribution Margin**												
27	Resulting Revenues		$ 27,501,228	$ 1,101,470	$ 8,126,982	$ 1,020,534	$ 5,560,210	$ 1,182,608	$ 1,698,150	$ 1,620,086	$ 1,197,813	$ 826,413	$ 1,147,705
28	Distribution Margin	$ 39,796,841	$ 20,731,783	$ 493,626	$ 6,745,829	$ 1,024,226	$ 5,235,691	$ 1,396,947	$ 1,545,114	$ 2,623,624			
29	Increase on Distribution Margin		$ 4,175,039	$ 99,408	$ 1,358,499	$ 206,262	$ 1,054,382	$ 281,322	$ 311,161	$ 528,355			
30	% Change on Dist Margin (equal % on Dist Margin)		20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%			
31	Resulting Revenues	$ 50,983,199	$ 24,906,823	$ 593,034	$ 8,104,328	$ 1,230,488	$ 6,290,072	$ 1,678,269	$ 1,856,275	$ 3,151,979	$ 1,197,813	$ 826,413	$ 1,147,705

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Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Design Day with Customer Component of Mains
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52
	Functional Rate Base									
1	**Indirect Production & O.H.**									
2	Demand	$ 408,158	$ 196,799	$ 2,327	$ 92,154	$ 7,513	$ 37,980	$ 39,291	$ 26,993	$ 5,101
3	Commodity	$ 93,270	$ 44,971	$ 532	$ 21,058	$ 1,717	$ 8,679	$ 8,979	$ 6,168	$ 1,166
4	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Subtotal	$ 501,428	$ 241,770	$ 2,859	$ 113,212	$ 9,230	$ 46,659	$ 48,270	$ 33,161	$ 6,267
6	**Distribution**									
7	Demand	$ 76,812,163	$ 27,202,195	$ 264,752	$ 13,568,322	$ 880,793	$ 19,025,955	$ 2,786,965	$ 6,752,549	$ 6,330,633
8	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Customer	$ 39,785,691	$ 30,314,965	$ 1,443,349	$ 5,917,579	$ 939,999	$ 796,158	$ 301,287	$ 35,046	$ 37,308
10	Subtotal	$ 116,597,855	$ 57,517,160	$ 1,708,101	$ 19,485,902	$ 1,820,792	$ 19,822,113	$ 3,088,251	$ 6,787,595	$ 6,367,941
11	**Onsite**									
12	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Customer	$ 71,433,607	$ 46,882,378	$ 2,252,315	$ 12,538,424	$ 1,991,980	$ 4,342,033	$ 1,632,132	$ 869,667	$ 924,677
15	Subtotal	$ 71,433,607	$ 46,882,378	$ 2,252,315	$ 12,538,424	$ 1,991,980	$ 4,342,033	$ 1,632,132	$ 869,667	$ 924,677
16	**Customer Accounts & Services**									
17	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Customer	$ 186,368	$ 296,455	$ 15,204	$ (3,569)	$ (13,247)	$ (73,355)	$ (28,787)	$ (7,673)	$ 1,340
20	Subtotal	$ 186,368	$ 296,455	$ 15,204	$ (3,569)	$ (13,247)	$ (73,355)	$ (28,787)	$ (7,673)	$ 1,340
31	**Total**									
32	Demand	$ 77,220,321	$ 27,398,994	$ 267,079	$ 13,660,476	$ 888,306	$ 19,063,934	$ 2,826,256	$ 6,779,542	$ 6,335,734
33	Commodity	$ 93,270	$ 44,971	$ 532	$ 21,058	$ 1,717	$ 8,679	$ 8,979	$ 6,168	$ 1,166
34	Customer	$ 111,405,666	$ 77,493,798	$ 3,710,869	$ 18,452,434	$ 2,918,733	$ 5,064,835	$ 1,904,632	$ 897,040	$ 963,325
35	**TOTAL RATE BASE**	$ 188,719,257	$ 104,937,763	$ 3,978,479	$ 32,133,969	$ 3,808,756	$ 24,137,449	$ 4,739,867	$ 7,682,750	$ 7,300,225

Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Design Day with Customer Component of Mains
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52
	Functional Revenue Requirement									
36	**Indirect Production & O.H.**									
37	Demand	$ 186,350	$ 89,851	$ 1,062	$ 42,074	$ 3,430	$ 17,340	$ 17,939	$ 12,324	$ 2,329
38	Commodity	$ 640,064	$ 308,616	$ 3,649	$ 144,513	$ 11,782	$ 59,559	$ 61,616	$ 42,329	$ 8,000
39	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Subtotal	$ 826,413	$ 398,466	$ 4,711	$ 186,587	$ 15,213	$ 76,899	$ 79,555	$ 54,653	$ 10,329
41	**Distribution**									
42	Demand	$ 16,742,400	$ 5,929,139	$ 57,707	$ 2,957,426	$ 191,982	$ 4,147,001	$ 607,462	$ 1,471,823	$ 1,379,859
43	Commodity	$ 180,290	$ 86,929	$ 1,028	$ 40,706	$ 3,319	$ 16,776	$ 17,356	$ 11,923	$ 2,253
44	Customer	$ 8,258,399	$ 6,292,540	$ 299,599	$ 1,228,324	$ 195,118	$ 165,260	$ 62,539	$ 7,275	$ 7,744
45	Subtotal	$ 25,181,089	$ 12,308,609	$ 358,334	$ 4,226,456	$ 390,419	$ 4,329,038	$ 687,356	$ 1,491,020	$ 1,389,857
46	**Onsite**									
47	**Demand**									
47	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	Customer	$ 20,530,081	$ 13,362,790	$ 651,400	$ 3,578,824	$ 568,957	$ 1,341,303	$ 498,865	$ 255,592	$ 272,350
50	Subtotal	$ 20,530,081	$ 13,362,790	$ 651,400	$ 3,578,824	$ 568,957	$ 1,341,303	$ 498,865	$ 255,592	$ 272,350
51	**Customer Accounts & Services**									
52	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	Customer	$ 4,445,616	$ 3,420,336	$ 157,068	$ 632,591	$ 101,567	$ 78,054	$ 37,303	$ 7,095	$ 11,602
55	Subtotal	$ 4,445,616	$ 3,420,336	$ 157,068	$ 632,591	$ 101,567	$ 78,054	$ 37,303	$ 7,095	$ 11,602
66	**Total**									
67	Demand	$ 16,928,750	$ 6,018,990	$ 58,769	$ 2,999,500	$ 195,413	$ 4,164,341	$ 625,401	$ 1,484,146	$ 1,382,189
68	Commodity	$ 820,354	$ 395,545	$ 4,677	$ 185,219	$ 15,101	$ 76,335	$ 78,972	$ 54,253	$ 10,253
69	Customer	$ 33,234,095	$ 23,075,666	$ 1,108,067	$ 5,439,740	$ 865,641	$ 1,584,617	$ 598,707	$ 269,962	$ 291,696
70	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 50,983,199	$ 29,490,202	$ 1,171,513	$ 8,624,458	$ 1,076,155	$ 5,825,294	$ 1,303,080	$ 1,808,361	$ 1,684,138
71	Demand	33.20%	20.41%	5.02%	34.78%	18.16%	71.49%	47.99%	82.07%	82.07%
72	Energy	1.61%	1.34%	0.40%	2.15%	1.40%	1.31%	6.06%	3.00%	0.61%
73	Customer	65.19%	78.25%	94.58%	63.07%	80.44%	27.20%	45.95%	14.93%	17.32%

Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Design Day with Customer Component of Mains
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52
	Unit Costs									
74	**Indirect Production & O.H.**									
75	Demand	$ 2.81	$ 3.83	$ 4.65	$ 3.59	$ 4.51	$ 1.06	$ 7.46	$ 2.11	$ 0.43
76	Commodity	$ 8.63	$ 15.38	$ 15.38	$ 13.28	$ 7.99	$ 4.13	$ 12.94	$ 7.19	$ 0.49
77	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	**Distribution**									
79	Demand	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46
80	Commodity	$ 0.00	$ 4.33	$ 4.33	$ 3.74	$ 2.25	$ 1.16	$ 3.65	$ 2.02	$ 0.14
81	Customer	$ 19.56	$ 19.56	$ 19.56	$ 19.56	$ 19.56	$ 19.56	$ 19.56	$ 19.56	$ 19.56
82	**Onsite**									
83	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	Customer	$ 48.61	$ 41.53	$ 42.52	$ 56.98	$ 57.02	$ 158.72	$ 155.99	$ 687.08	$ 687.75
86	**Customer Accounts & Services**									
87	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	Customer	$ 10.53	$ 10.63	$ 10.25	$ 10.07	$ 10.18	$ 9.24	$ 11.66	$ 19.07	$ 29.30
98	**Total - Distribution**									
99	Demand - Distribution	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46
100	Commodity - Distribution	$ 0.0024	$ 0.0043	$ 0.0043	$ 0.0037	$ 0.0023	$ 0.0012	$ 0.0036	$ 0.0020	$ 0.0001
101	Customer (per cust month)	$ 78.70	$ 71.71	$ 72.33	$ 86.60	$ 86.76	$ 187.51	$ 187.21	$ 725.70	$ 736.61
102	Customer (Onsite/Metering & Cust Acts)	$ 59.14	$ 52.16	$ 52.77	$ 67.05	$ 67.20	$ 167.96	$ 167.66	$ 706.15	$ 717.05
103	Demand & Customer (per cust month)	$ 118.78	$ 90.42	$ 76.16	$ 134.36	$ 106.34	$ 680.29	$ 382.77	$ 4,715.34	$ 4,226.98
104	**BILLING DETERMINANTS**									
105	Demand	66,317	23,486	229	11,714	760	16,426	2,406	5,830	5,466
106	Commodity	74,152,109	20,067,257	237,269	10,880,833	1,474,573	14,423,832	4,761,300	5,889,772	16,417,274
107	Customers (Number of Bills)	422,304	321,778	15,320	62,812	9,978	8,451	3,198	372	396

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Northern Utilities New Hampshire
External Class Allocation Factors

Line	Allocation Factor	Description	Total	Residential Heat	Residential Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
				R-5, R-10	R-6, R-11	G-40, T-40	G-50, T-50	G-41, T-41	G-51, T-51	G-42, T-42	G-52, T-52
1	**DEMAND ALLOCATION FACTORS**										
2	**Design Day**										
3		Design Peak Day	66,317	23,486	229	11,714	760	16,426	2,406	5,830	5,466
4	DESIGN_DAY	Design Peak Day Percent	100%	35.41%	0.34%	17.66%	1.15%	24.77%	3.63%	8.79%	8.24%
5	**CUSTOMER ALLOCATORS**										
6	**Customer Count**										
7		December 2020 Customer Count	35,192	26,815	1,277	5,234	831	704	267	31	33
8	CUSTOMERS	December 2020 Customer Count Percent	100%	76.20%	3.63%	14.87%	2.36%	2.00%	0.76%	0.09%	0.09%
9	**Telemetry Customers**										
10		2020 Telemetered Customers	73	-	-	1	2	16	3	21	30
11	CUST_TELEMETER	2020 Telemetered Customers Percent	100%	0.00%	0.00%	1.37%	2.74%	21.92%	4.11%	28.77%	41.10%
12	**Customers Excluding Telemetered (ERTs)**										
13		2020 Customers excluding Telemetered	35,119	26,815	1,277	5,233	829	688	264	10	3
14	ERTS	2020 Customers excluding Telemetered Percent	100%	76.35%	3.64%	14.90%	2.36%	1.96%	0.75%	0.03%	0.01%
15	**Customer Meters**										
16		Meter Replacement Cost	21,291,856	12,464,988	593,480	3,963,830	629,649	2,110,810	798,784	353,746	376,568
17	METERS	Meter Replacement Cost Percent	100%	58.54%	2.79%	18.62%	2.96%	9.91%	3.75%	1.66%	1.77%
18	**Services Lines**										
19		Services at Current Costs	163,283,766	111,591,172	5,313,054	28,238,845	4,485,702	7,312,260	2,767,147	1,731,925	1,843,662
20	SERVICES	Services at Current Costs Percent	100%	68.34%	3.25%	17.29%	2.75%	4.48%	1.69%	1.06%	1.13%
21	**Write-offs / Uncollectible, Distribution**										
22		2018-2020 Average Write-offs, Distribution	254,119	214,169	6,803	22,634	4,468	-	4,885	-	1,161
23	DIST_UNCOLLECT	2018-2020 Average Write-offs, Distribution %	100%	84.28%	2.68%	8.91%	1.76%	0.00%	1.92%	0.00%	0.46%
24	**Meter Reading (FERC 902)**										
25		Relative Weighting Factor		1.00	1.00	1.02	1.06	1.30	1.14	10.60	13.86
26		Weighted Customers	36,333	26,815	1,277	5,360	877	915	303	329	457
27	METER_READ	Weighted Customers Percent	100%	73.80%	3.51%	14.75%	2.41%	2.52%	0.83%	0.90%	1.26%
28	**Customer Deposits**										
29		Customer Deposits (12/31/2020)	249,403	33,843	523	68,253	23,565	82,404	32,116	8,699	-
30	CUST_DEPOSITS	Customer Deposits (12/31/2020) Percent	100%	13.57%	0.21%	27.37%	9.45%	33.04%	12.88%	3.49%	0.00%

Northern Utilities New Hampshire
External Class Allocation Factors

Line	Allocation Factor	Description	Total	Residential Heat	Residential Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
				R-5, R-10	R-6, R-11	G-40, T-40	G-50, T-50	G-41, T-41	G-51, T-51	G-42, T-42	G-52, T-52
31	**COMMODITY and REVENUE ALLOCATORS**										
32	**Total Volume**										
33		2020 Adjusted Billing Determinants	74,152,109	20,067,257	237,269	10,880,833	1,474,573	14,423,832	4,761,300	5,889,772	16,417,274
34	TOTAL_VOLUME	2020 Adjusted Billing Determinants Percent	100%	27.06%	0.32%	14.67%	1.99%	19.45%	6.42%	7.94%	22.14%
35	**Sales Volume (excludes Transportation)**										
36		2020 Adjusted Sales Billing Determinants	41,619,185	20,067,257	237,269	9,396,744	766,130	3,872,741	4,006,477	2,752,408	520,161
37	SALES_VOLUME	2020 Adjusted Sales Billing Determinants Percent	100%	48.22%	0.57%	22.58%	1.84%	9.31%	9.63%	6.61%	1.25%
38	**Sales Volume (excludes Transportation) - Allocation of Indirect Production & Overhead**										
39		2020 Adjusted Sales Billing Determinants	41,619,185	20,067,257	237,269	9,396,744	766,130	3,872,741	4,006,477	2,752,408	520,161
40	IND_PROD_OH	2020 Adjusted Sales Billing Determinants Percent	100%	48.22%	0.57%	22.58%	1.84%	9.31%	9.63%	6.61%	1.25%
38	**Test Year Revenue**										
41		2020 Pro Forma Revenue at Current Rates	39,796,840	20,731,783	493,626	6,745,829	1,024,226	5,235,691	1,396,947	1,545,114	2,623,624
42	BASE_REVENUE	2020 Pro Forma Revenue at Current Rates Percent	100%	52.09%	1.24%	16.95%	2.57%	13.16%	3.51%	3.88%	6.59%
38	**Late Fees**										
43		2018-2020 Avg Late Fees	69,249	49,293	1,334	7,540	1,468	5,421	2,086	713	1,394
44	LATE_FEES	2018-2020 Avg Late Fees Percent	100%	71.18%	1.93%	10.89%	2.12%	7.83%	3.01%	1.03%	2.01%
45	**Miscellaneous Service Revenue**										
46		Other Revenue	852,295	727,388	32,194	62,248	9,249	14,084	1,975	2,134	3,023
47	MISC_REVENUE	Other Revenue Percent	100%	85.34%	3.78%	7.30%	1.09%	1.65%	0.23%	0.25%	0.35%
48	**Water Heater and Burner Conversion Revenue**										
49		Water Heater and Burner Conversion Revenue	249,162	204,026	15,142	18,735	3,119	8,140	-	-	-
50	HEAT_CONV_REV	Water Heater and Burner Conversion Revenue Percent	100%	81.88%	6.08%	7.52%	1.25%	3.27%	0.00%	0.00%	0.00%
51	**Direct Assignment to Low Income**										
52		Customer Deposits	1	1	-	-	-	-	-	-	-
53	RES_LOW_INCOME	Customer Deposits Percent	100%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
54	***FUNCTIONAL PLANT ALLOCATORS***										
55	**Misc. Intangible Plant Split**										
56	Plant Related	Account 303 related to plant	1.7%								
57	Customer Related	Account 303 related to billing, meter reading, customer accounts	70.5%								
58	Labor Related	Account 303 related to operations, IT, finance accounting, employees	27.9%								

Northern Utilities New Hampshire

Description of ACOSS Functionalization and Classification of Accounts

FERC	Description	Functionalization	Classification
Intangible Plant			
301-303	*Intangible Plant*		
303	Miscellaneous Intangible Plant, Plant-related	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
303	Miscellaneous Intangible Plant, Customer-related	Distribution	Customer-related
303	Miscellaneous Intangible Plant, Labor-related	Labor expense	Labor expense
Manufactured Gas Production Plant and Expenses			
304-321	*Other Production Plant*		
304	Land and Land Rights	Indirect Production and OH	Demand-related
305	Structures & Improvements	Indirect Production and OH	Demand-related
320	Other Equipment	Indirect Production and OH	Demand-related
321	LNG Equipment	Indirect Production and OH	Demand-related
710-735	*Manufactured Gas Production Plant Expenses*		
710	Supervision	Indirect Production and OH	Demand-related
717	Propane Expenses	Indirect Production and OH	Demand-related
735	Misc. Intangible Plant	Indirect Production and OH	Demand-related
Other Storage Plant, Other Gas & Operation Expenses			
360-369	*Other Storage Plant*		
360	Land-Lewiston	Indirect Production and OH	Demand-related
361	Structures & Improvements	Indirect Production and OH	Demand-related
362	Gas Holders	Indirect Production and OH	Demand-related
363	Other Equipment	Indirect Production and OH	Demand-related

FERC	Description	Functionalization	Classification
740-769	*Maintenance Expenses*		
740	Supervision	Indirect Production and OH	Demand-related
741	Maintenance of Plant	Indirect Production and OH	Demand-related
742	Maintenance of Equipment	Indirect Production and OH	Demand-related
769	Maintenance of Scada - Production	Indirect Production and OH	Demand-related
800-813	*Other Gas Expenses*		
813	Other Gas Expenses	Indirect Production and OH	Commodity-related
813	Other Gas Supply Expenses – Del Serv	Distribution	Commodity-related
851-852	*Operation Expenses*		
851	System Control/Load Dispatching	Distribution	Demand-related
851	System Control//Load Dispatching – Gas Supply	Indirect Production and OH	Demand-related
852	Communication System Expense	Distribution	Demand-related
Distribution Plant and Expenses			
374-386	*Distribution Plant*		
374	Land and Land Rights	Distribution	Demand-related
375	Structures and Improvements	Distribution	Demand-related
376	Mains	Distribution	Demand and Customer based on zero-intercept analysis
378	M&R Station Equipment - Regulating	Distribution	Demand-related
379	M&R Station Equipment - Gate	Distribution	Demand-related
380	Services	Onsite	Customer-related
381	Meters	Onsite	Customer-related
382	Meter Installations	Onsite	Customer-related
383	House Regulators	Onsite	Customer-related
386	Water Heaters/Conversion Burners	Onsite	Customer-related

FERC	Description	Functionalization	Classification
870-894	*Distribution Expenses*		
870	Op Supervision-Engineering-Gas Distribution	Accts 874-879	Accts 874-879
874	Mains & Services	Mains and Services Plant	Mains and Services Plant
875	Regulator Station Expense	Distribution	Demand-related
878	Meter & House Regulator	Onsite	Customer-related
879	Customer Installation Exp	Onsite	Customer-related
880	Operations Exp Other	Accts 874-879	Accts 874-879
885	Maintenance Supervision	Accts 887-894	Accts 887-894
886	Structures & Improvements	Accts 887-894	Accts 887-894
887	Mains	Distribution	Demand and Customer based on zero-intercept analysis
889	Measuring & Regulating - Atatew EQ	Distribution	Demand-related
890	Measuring & Regulating - EQ Industry	Distribution	Demand-related
891	Measuring & Regulating - EQ City Gate	Distribution	Demand-related
891	Main Distribution SCADA	Distribution	Demand-related
892	Services	Onsite	Customer-related
893	Meters & House Regulators	Onsite	Customer-related
894	Other Equipment	Accts 874-879	Accts 874-879
894	Water Heaters & Conv Burn	Onsite	Customer-related
General Plant			
389-399	*General & Common Plant*		
389	Land & Land Rights	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
391	Office Furniture & Equipment	Labor expense	Labor expense

FERC	Description	Functionalization	Classification
393	Stores Equipment	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
394	Tools, Shop & Garage Equip.	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
396	Power Operated Equipment	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
397	Communication Equipment	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
397.3	Metscan Communication Equipment	Onsite	Customer-related
397.4	ERT Automatic Reading Devices	Onsite	Customer-related
Depreciation Reserve			
108	Accumulated Depreciation	Corresponding plant accts.	Corresponding plant accts.
Other Rate Base Items			
154	Materials and Supplies	Distribution Plant	Distribution Plant
165	Prepayments	Distribution Plant	Distribution Plant
131	Cash Working Capital	Total plant in service	Total plant in service
235	Customer Deposits	Accounts & Services	Customer-related
283	Net Deferred Income Taxes	Total plant in service	Total plant in service
254	Excess Deferred Income Taxes	Total plant in service	Total plant in service
Customer Expenses			
901-905	Customer Accounts Expense	Accounts & Services	Customer-related
906-910	Customer Service & Information Expense	Accounts & Services	Customer-related
911-917	Sales Expense	Accounts & Services	Customer-related
Administrative and General Expenses			
920	Administrative & General Salaries	Labor expense	Labor expense

FERC	Description	Functionalization	Classification
921	Office Supplies & Expenses	Labor expense	Labor expense
923	Outside Services Employed	Labor expense	Labor expense
924	Property Insurance	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
925	Injuries and Damages	Labor expense	Labor expense
926	Employee Pensions and Benefits	Labor expense	Labor expense
928	Regulatory Commission Expenses	Rate Base	Rate Base
930	General/Miscellaneous Expenses	Labor expense	Labor expense
931	Rents	Labor expense	Labor expense
932	Maintenance of General Plant – Equip Shared	General Plant	General Plant
935	Maintenance of General Plant	General Plant	General Plant
Depreciation and Amortization Expenses			
403	Depreciation Expense	Corresponding plant accts.	Corresponding plant accts.
404-407	Amortization Expense	Intangible Plant	Intangible Plant
407	Excess ADIT Flow Back	Rate Base	Rate Base
Taxes Other Than Income			
408	Payroll Taxes	Labor expense	Labor expense
408	Unemployment Tax	Labor expense	Labor expense
408	Property Taxes	Total plant in service	Total plant in service
408	Payroll Taxes - Capitalized	Labor expense	Labor expense
408	Other Taxes	Rate Base	Rate Base
Income Taxes			
409-410	Income Taxes	Rate base	Rate base

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Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Customer Component of Mains

Minimum System Summary

Material	Quantity	Cost 2020	Minimum Size Cost (2020)	Customer Component	Customer Component Percentage
Plastic	2,572,194	$149,782,247	$32.58	$83,795,365	55.9%
Steel	421,064	$70,715,971	$32.58	$13,717,152	19.4%
Total	**2,993,258**	**$220,498,219**		**$97,512,517**	**44.2%**

Zero-Intercept Summary

Material	Quantity	Cost 2020	Zero-Intercept Cost (2020)	Customer Component	Customer Component Percentage
Plastic	2,572,194	$149,782,247	$25.21	$64,845,019	43.3%
Steel	421,064	$70,715,971	$25.21	$10,615,014	15.0%
Total	**2,993,258**	**$220,498,219**		**$75,460,033**	**34.2%**
				Rounded Customer Component	**34%**

ADJUSTED MINIMUM SYSTEM

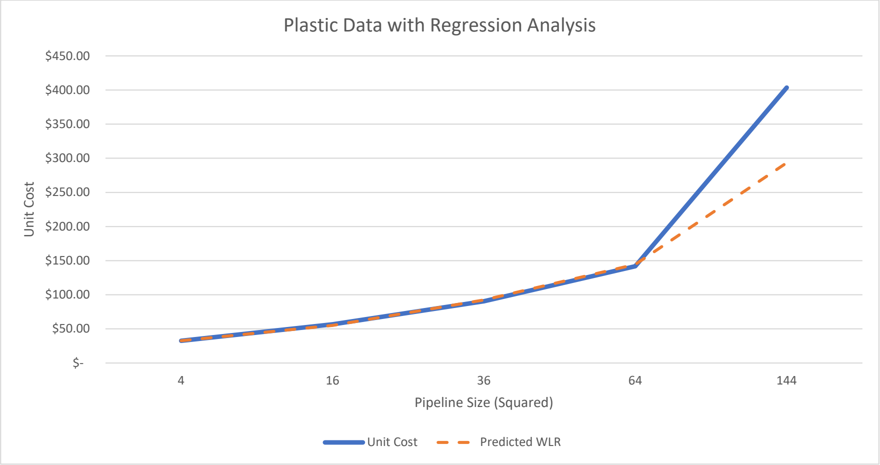
Minimum System Cost		$97,512,517
		x
Minimum System Serving Design Day Demand (%)		6.11%
		=
Minimum System Serving Design Day Demand (Total)	$	5,954,778.30
Remaining Customer Portion	$	91,557,738
		/
Total Plastic & Steel Cost		$220,498,219
		=
		41.52%

Description	Amount	
2 Inch Main	2	
Pipe Diameter Squared	4	Line 1 squared
Constant	0.372	
PSIG	40	
Cubic Feet of Capacity per Thousand Feet	59.52	Multiply lines 2 - 4
Feet in Mile (1,000s)	5.28	
Cubic Feet of Capacity per Mile	314.27	Line 5 * Line 6
Hours in Day	24	
Cubic Feet of Capacity per Mile per Day	7,542	Line 7 * Line 8
Total Design Day (in Ccf)	699,920	*Design Day from Company
Total Customers	35,194	
Ccf Per Customer on Design Day	19.89	Line 10 / Line 11
Customers Per Mile	62.10	Line 20
Capacity (Ccf) Required on Design Day per Mile	1235.1	Line 12 * Line 13
Cubic Feet of Capacity per Mile	7,542	Line 9
Ccf of Capacity per Mile	75.42	Line 15 / 100
Portion of Required Capacity Met by 2 Inch Main Capacity	6.11%	Line 16 / Line 14
Miles of Main from 2020 DOT Report	566.69	
Total Customers	35,194	
Customers Per Mile	62.10	

Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Zero-Intercept Mains Study

Plastic Data	Used as X-value for Regression		Weights Used for Regression				Equation: 25.208+1.862x Weighted Linear Regression
Size (Inches)	Size (Inches-Squared)	GIS footage	% Total Footage	Acct. Dollars	2020$	Unit Cost	Predicted WLR
2	4	1,199,189	47.24460%	$ 25,998,228	$ 39,066,445	$ 32.58	32.656
4	16	634,672	25.00426%	$ 25,161,778	$ 36,055,758	$ 56.81	55
6	36	508,384	20.02888%	$ 32,129,456	$ 46,029,660	$ 90.54	92.24
8	64	193,207	7.61182%	$ 24,779,188	$ 27,416,116	$ 141.90	144.376
12	144	2,803	0.11044%	$ 967,760	$ 1,131,176	$ 403.54	293.336
Total		2,538,256	100.00%	$ 109,036,410	$ 149,699,156	$ 725.37	

```
#Weighted Linear Regression Formula
weighted_regression
##
## Call:
## lm(formula = Plastic_UnitCost ~ Size_Squared, data = Plastic_DF,
##     weights = Plastic_Weights)
##
## Coefficients:
##  (Intercept)  Size_Squared
##       25.208         1.862
#Regression Summary
summary(weighted_regression)
##
## Call:
## lm(formula = Plastic_UnitCost ~ Size_Squared, data = Plastic_DF,
##     weights = Plastic_Weights)
##
## Weighted Residuals:
##        1        2        3        4        5
## -0.05539  0.90138 -0.76773 -0.69121  3.66003
##
## Coefficients:
##              Estimate Std. Error t value Pr(>|t|)
## (Intercept)   25.2081     3.1717   7.948 0.004155 **
## Size_Squared   1.8625     0.1229  15.152 0.000624 ***
## ---
## Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
##
## Residual standard error: 2.257 on 3 degrees of freedom
## Multiple R-squared:  0.9871, Adjusted R-squared:  0.9828
## F-statistic: 229.6 on 1 and 3 DF,  p-value: 0.0006242
```



Steel Data	Used as X-value for Regression		Weights Used for Regression				**Equation: 19.92+3.37x** **Weighted Linear Regression**
Size (Inches)	**Size (Inches-Squared)**	**GIS footage**	**% Total Footage**	**Acct. Dollars**	**2020$**	**Unit Cost**	**Predicted WLR**
2	4	37,133	8.94%	$ 1,137,562	$ 5,750,794	$ 154.87	33.39489
4	16	97,838	23.54%	$ 2,743,699	$ 10,973,455	$ 112.16	73.83427
6	36	87,630	21.09%	$ 2,578,887	$ 9,787,549	$ 111.69	141.23322
8	64	175,766	42.30%	$ 11,984,562	$ 30,987,019	$ 176.30	235.59176
10	100	1,853	0.45%	$ 207,703	$ 703,927	$ 379.87	356.90988
12	144	15,326	3.69%	$ 10,690,515	$ 12,450,031	$ 812.36	505.18758
Total		415,545	100.00%	$ 29,342,928	$ 70,652,775	$ 1,747.26	

```
#Weighted Linear Regression Formula
weighted_regression
##
## Call:
## lm(formula = Steel_UnitCost ~ Size_Squared, data = Steel_DF,
##     weights = Steel_Weights)
##
## Coefficients:
##  (Intercept)  Size_Squared
##        19.92          3.37
#Regression Summary
summary(weighted_regression)
##
## Call:
## lm(formula = Steel_UnitCost ~ Size_Squared, data = Steel_DF,
##     weights = Steel_Weights)
##
## Weighted Residuals:
##       1       2       3       4       5       6
##  36.313  18.597 -13.566 -38.563   1.533  58.991
##
## Coefficients:
##              Estimate Std. Error t value Pr(>|t|)
## (Intercept)    19.915     74.113   0.269   0.8014
## Size_Squared    3.370      1.382   2.439   0.0713 .
## ---
## Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
##
## Residual standard error: 41.29 on 4 degrees of freedom
## Multiple R-squared:  0.5979, Adjusted R-squared:  0.4974
## F-statistic: 5.948 on 1 and 4 DF,  p-value: 0.07129
```

Northern Utilities New Hampshire
2021 Rate Case Gas Marginal Cost of Service Study
Marginal Cost Summary

A	B	C	D	E	F	G	H	I	J	K	L
				Residential Heat	Residentail Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
Line	FERC A/C	Description	Total System	R-5, R-10	R-6, R-11	G-40, T-40	G-50, T-50	G-41, T-41	G-51, T-51	G-42, T-42	G-52, T-52
1	**MARGINAL COST BASED REVENUE REQUIREMENTS REPORT**										
2		**Demand Related Carrying Costs**									
3	376	Reinforcement/Pipe Replacement	$ 9,985,255	$ 3,536,170	$ 34,417	$ 1,763,824	$ 114,499	$ 2,473,293	$ 362,294	$ 877,803	$ 822,955
4	376	Mains Extension - Demand Component	$ 7,789,012	$ 2,758,394	$ 26,847	$ 1,375,874	$ 89,315	$ 1,929,296	$ 282,608	$ 684,731	$ 641,948
5		Subtotal: Demand Related Carrying Costs	$ 17,774,267	$ 6,294,564	$ 61,263	$ 3,139,698	$ 203,815	$ 4,402,589	$ 644,901	$ 1,562,534	$ 1,464,903
6		**Demand Related O&M Costs**									
7	920-935	A&G Expense - Demand Related	$ 2,146,279	$ 760,081	$ 7,398	$ 379,125	$ 24,611	$ 531,622	$ 77,873	$ 188,679	$ 176,890
8		Subtotal: Demand O&M Costs	$ 2,146,279	$ 760,081	$ 7,398	$ 379,125	$ 24,611	$ 531,622	$ 77,873	$ 188,679	$ 176,890
9		**Total: Demand Related Costs**	**$ 19,920,546**	**$ 7,054,645**	**$ 68,661**	**$ 3,518,823**	**$ 228,426**	**$ 4,934,211**	**$ 722,774**	**$ 1,751,213**	**$ 1,641,793**
10		**Customer Related Carrying Costs**									
11	376	Mains Extension - Customer Component	$ 5,171,273	$ 3,940,285	$ 187,604	$ 769,156	$ 122,179	$ 103,483	$ 39,161	$ 4,555	$ 4,849
12	380	Services	$ 15,506,102	$ 10,597,159	$ 504,550	$ 2,681,678	$ 425,981	$ 694,402	$ 262,780	$ 164,471	$ 175,082
13	381-383	Meters, Installations, Regulators	$ 2,944,304	$ 1,723,697	$ 82,068	$ 548,131	$ 87,070	$ 291,889	$ 110,458	$ 48,917	$ 52,073
14		Subtotal: Demand Related Carrying Costs	$ 18,450,406	$ 12,320,857	$ 586,618	$ 3,229,808	$ 513,051	$ 986,292	$ 373,238	$ 213,388	$ 227,155
15		**Customer Related O&M Costs**									
16	902	Meter Reading Expenses	$ 202,880	$ 149,729	$ 7,129	$ 29,930	$ 4,899	$ 5,111	$ 1,694	$ 1,835	$ 2,554
17	903	Customer Records & Collection Expenses	$ 2,052,586	$ 1,563,982	$ 74,464	$ 305,294	$ 48,496	$ 41,075	$ 15,544	$ 1,808	$ 1,925
18	904	Uncollectible Accounts	$ 437,750	$ 368,931	$ 11,718	$ 38,990	$ 7,696	$ -	$ 8,415	$ -	$ 2,000
19	908	Customer Assistance Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	909	Informational and Instructional Advertising Exp.	$ 73,965	$ 56,358	$ 2,683	$ 11,001	$ 1,748	$ 1,480	$ 560	$ 65	$ 69
21	920-935	Customer A&G Costs	$ 5,092,681	$ 3,418,714	$ 166,346	$ 849,158	$ 135,185	$ 304,929	$ 112,969	$ 50,554	$ 54,825
22		Subtotal: Customer O&M Costs	$ 7,859,863	$ 5,557,714	$ 262,341	$ 1,234,374	$ 198,023	$ 352,595	$ 139,182	$ 54,261	$ 61,373
23		**Total: Customer Related Costs**	**$ 26,310,269**	**$ 17,878,570**	**$ 848,959**	**$ 4,464,182**	**$ 711,074**	**$ 1,338,886**	**$ 512,420**	**$ 267,649**	**$ 288,528**
24		**Total LRIC Based Revenue Requirement**	**$ 46,230,815**	**$ 24,933,216**	**$ 917,620**	**$ 7,983,005**	**$ 939,500**	**$ 6,273,097**	**$ 1,235,195**	**$ 2,018,862**	**$ 1,930,321**
25		**Actual Revenue Requirement**	**$ 50,983,199**								
26		**True-up Factor**	**1.1028**								
27		**Allocated Actual Revenue Requirement**	**$ 50,983,199**	**$ 27,496,273**	**$ 1,011,948**	**$ 8,803,633**	**$ 1,036,077**	**$ 6,917,952**	**$ 1,362,169**	**$ 2,226,395**	**$ 2,128,752**
28		**Revenue to Cost Ratio**	0.85	0.83	0.56	0.83	1.05	0.80	1.13	0.75	1.27

Northern Utilities New Hampshire
2021 Rate Case Gas Marginal Cost of Service Study
Marginal Cost Summary

A	B	C	D	E	F	G	H	I	J	K	L
Line	FERC A/C	Description	Total System	Residential Heat	Residentail Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
				R-5, R-10	R-6, R-11	G-40, T-40	G-50, T-50	G-41, T-41	G-51, T-51	G-42, T-42	G-52, T-52
29	**MARGINAL UNIT COST REPORT**										
30		**Demand Related Carrying Costs**									
31	376	Reinforcement/Pipe Replacement	$ 150.57	$ 150.57	$ 150.57	$ 150.57	$ 150.57	$ 150.57	$ 150.57	$ 150.57	$ 150.57
32	376	Mains Extension - Demand Component	$ 117.45	$ 117.45	$ 117.45	$ 117.45	$ 117.45	$ 117.45	$ 117.45	$ 117.45	$ 117.45
33		Subtotal: Demand Related Carrying Costs	$ 268.02	$ 268.02	$ 268.02	$ 268.02	$ 268.02	$ 268.02	$ 268.02	$ 268.02	$ 268.02
34		**Demand Related O&M Costs**									
35	920-935	A&G Expense - Demand Related	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36
36		Subtotal: Demand O&M Costs	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36
37		**Total: Demand Related Costs**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**
38		Monthly Costs	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**
39		**Customer Related Carrying Costs**									
	376	Mains Extension - Customer Component	$ 146.94	$ 146.94	$ 146.94	$ 146.94	$ 146.94	$ 146.94	$ 146.94	$ 146.94	$ 146.94
40	380	Services	$ 440.61	$ 395.20	$ 395.20	$ 512.32	$ 512.32	$ 986.04	$ 986.04	$ 5,305.51	$ 5,305.51
41	381-383	Meters, Installations, Regulators	$ 83.66	$ 64.28	$ 64.28	$ 104.72	$ 104.72	$ 414.48	$ 414.48	$ 1,577.97	$ 1,577.97
42		Subtotal: Customer Related Carrying Costs	$ 524.28	$ 459.48	$ 459.48	$ 617.04	$ 617.04	$ 1,400.52	$ 1,400.52	$ 6,883.48	$ 6,883.48
43		**Customer Related O&M Costs**									
44	902	Meter Reading Expenses	$ 5.76	$ 5.58	$ 5.58	$ 5.72	$ 5.89	$ 7.26	$ 6.36	$ 59.18	$ 77.40
45	903	Customer Records & Collection Expenses	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33
46	904	Uncollectible Accounts	$ 12.44	$ 13.76	$ 9.18	$ 7.45	$ 9.26	$ -	$ 31.58	$ -	$ 60.60
47	908	Customer Assistance Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	909	Informational and Instructional Advertising Exp.	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10
49	920-935	Customer A&G Costs	$ 144.71	$ 127.49	$ 130.29	$ 162.23	$ 162.59	$ 432.99	$ 423.90	$ 1,630.76	$ 1,661.37
50		Subtotal: Customer O&M Costs	$ 223.34	$ 207.26	$ 205.48	$ 235.82	$ 238.16	$ 500.68	$ 522.26	$ 1,750.37	$ 1,859.79
51		**Total: Customer Related Costs**	**$ 747.62**	**$ 666.74**	**$ 664.96**	**$ 852.87**	**$ 855.20**	**$ 1,901.20**	**$ 1,922.78**	**$ 8,633.85**	**$ 8,743.27**
52		Monthly Costs	$ 62.30	$ 55.56	$ 55.41	$ 71.07	$ 71.27	$ 158.43	$ 160.23	$ 719.49	$ 728.61

Northern Utilities New Hampshire
2021 Rate Case Gas Marginal Cost of Service Study
Plant Investment

A	B	C	D	E	F	G	H	I	J	K	L	M
No.	FERC A/C	Description	Units	Total	Residential Heat	Residentail Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
1		**Billing Determenants**										
2		No. of Customers		35,192	26,815	1,277	5,234	831	704	267	31	33
3		Design Day Capacity	dt	66,317	23,486	229	11,714	760	16,426	2,406	5,830	5,466
4		Throughput	therms	74,152,109	20,067,257	237,269	10,880,833	1,474,573	14,423,832	4,761,300	5,889,772	16,417,274
5		Revenue		$ 43,200,249	$ 22,793,730	$ 561,877	$ 7,298,212	$ 1,082,956	$ 5,543,884	$ 1,542,422	$ 1,678,879	$ 2,698,288
6		**Demand Related Additions**										
7	376	Reinforcement/Pipe Replacement										
8		Investment per unit capacity	$/dt		$1,664	$1,664	$1,664	$1,664	$1,664	$1,664	$1,664	$1,664
9		Class investment	$	$ 110,375,535	$39,088,299	$380,437	$19,497,053	$1,265,659	$27,339,419	$4,004,740	$9,703,101	$9,096,828
10		ECCR	%		9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%
11		Annual Carrying Charge	$	$ 9,985,255	$3,536,170	$34,417	$1,763,824	$114,499	$2,473,293	$362,294	$877,803	$822,955
12		Unit Annual Carrying Costs	$/dt		$150.57	$150.57	$150.57	$150.57	$150.57	$150.57	$150.57	$150.57
13	376	Mains Extension - Demand Component										
14		Investment per unit capacity	$/dt		$1,298	$1,298	$1,298	$1,298	$1,298	$1,298	$1,298	$1,298
15		Class investment	$	$ 86,098,596	$30,490,884	$296,760	$15,208,705	$987,279	$21,326,153	$3,123,903	$7,568,918	$7,095,994
16		ECCR			9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%
17		Annual Carrying Charge	$	$ 7,789,012	$2,758,394	$26,847	$1,375,874	$89,315	$1,929,296	$282,608	$684,731	$641,948
18		Unit Annual Carrying Costs	$/dt		$117.45	$117.45	$117.45	$117.45	$117.45	$117.45	$117.45	$117.45
19		**Customer Related Additions**										
20	376	Mains Extension - Customer Component										
21		Investment per customer	$/Cust		$1,624	$1,624	$1,624	$1,624	$1,624	$1,624	$1,624	$1,624
22		Class investment	$	$ 57,162,494	$43,555,332	$2,073,747	$8,502,142	$1,350,554	$1,143,888	$432,877	$50,353	$53,602
23		ECCR			9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%
24		Annual Carrying Charge	$	$ 5,171,273	$3,940,285	$187,604	$769,156	$122,179	$103,483	$39,161	$4,555	$4,849
25		Unit Annual Carrying Costs	$/Cust		$146.94	$146.94	$146.94	$146.94	$146.94	$146.94	$146.94	$146.94
26	380	Services										
27		Investment per customer	$/Cust		$4,161.55	$4,161.55	$5,394.93	$5,394.93	$10,383.29	$10,383.29	$55,868.54	$55,868.54
28		Class investment	$	$ 163,283,766	$111,591,172	$5,313,054	$28,238,845	$4,485,702	$7,312,260	$2,767,147	$1,731,925	$1,843,662
29		ECCR			9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
30		Annual Carrying Charge	$	$ 15,506,102	$10,597,159	$504,550	$2,681,678	$425,981	$694,402	$262,780	$164,471	$175,082
31		Unit Annual Carrying Costs	$/Cust		$395.20	$395.20	$512.32	$512.32	$986.04	$986.04	$5,305.51	$5,305.51
32	381-383	Meters, Installations, Regulators										
33		Investment per customer	$/Cust		$464.85	$464.85	$757.27	$757.27	$2,997.32	$2,997.32	$11,411.16	$11,411.16
34		Class investment	$	$ 21,291,856	$12,464,988	$593,480	$3,963,830	$629,649	$2,110,810	$798,784	$353,746	$376,568
35		ECCR			13.83%	13.83%	13.83%	13.83%	13.83%	13.83%	13.83%	13.83%
36		Annual Carrying Charge	$	$ 2,944,304	$1,723,697	$82,068	$548,131	$87,070	$291,889	$110,458	$48,917	$52,073
37		Unit Annual Carrying Costs	$/Cust		$64.28	$64.28	$104.72	$104.72	$414.48	$414.48	$1,577.97	$1,577.97

Northern Utilities New Hampshire
2021 Rate Case Gas Marginal Cost of Service Study
Plant Investment

A	B	C	D	E	F	G	H	I	J	K	L	M
No.	FERC A/C	Description	Units	Total	Residential Heat	Residentail Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
38		**General Plant**										
39	389-398	Demand Related General Plant										
40		General Plant - ECOSS Demand Allocation		$ 1,951,305	$ 691,033	$ 6,726	$ 344,684	$ 22,375	$ 483,328	$ 70,799	$ 171,539	$ 160,821
41		Less: Accumulated Depreciation		$ (1,306,916)	$ (462,830)	$ (4,505)	$ (230,857)	$ (14,986)	$ (323,716)	$ (47,419)	$ (114,891)	$ (107,712)
42		Net General Plant - Demand Allocation		$ 644,389	$ 228,203	$ 2,221	$ 113,827	$ 7,389	$ 159,612	$ 23,380	$ 56,648	$ 53,109
43		Return on Ratebase (Pre Tax)			7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
44		Return on Ratebase (Pre Tax)		$ 49,924	$ 17,680	$ 172	$ 8,819	$ 572	$ 12,366	$ 1,811	$ 4,389	$ 4,115
45		Depreciation Expence		$ 30,626	$ 10,846	$ 106	$ 5,410	$ 351	$ 7,586	$ 1,111	$ 2,692	$ 2,524
46		Annual Carrying Charge	$	$ 80,550.43	$ 28,526.06	$ 277.64	$ 14,228.66	$ 923.66	$ 19,951.90	$ 2,922.60	$ 7,081.18	$ 6,638.73
47		Unit Annual Carrying Costs	$/kW		$1.21	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21
48	389-398	General Plant - Customer Related										
49		General Plant - ECOSS Customer Allocation		$ 5,735,962	$ 4,103,207	$ 196,178	$ 884,617	$ 143,215	$ 209,208	$ 74,270	$ 55,299	$ 69,967
50		Less: Accumulated Depreciation		$ (4,303,307)	$ (3,073,933)	$ (146,885)	$ (655,956)	$ (106,916)	$ (155,768)	$ (54,159)	$ (47,692)	$ (61,999)
51		Net General Plant - Demand Allocation		$ 1,432,655	$ 1,029,274	$ 49,293	$ 228,661	$ 36,299	$ 53,440	$ 20,111	$ 7,607	$ 7,969
52		Return on Ratebase (Pre Tax)			7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
53		Return on Ratebase (Pre Tax)		$ 110,996	$ 79,743	$ 3,819	$ 17,716	$ 2,812	$ 4,140	$ 1,558	$ 589	$ 617
54		Depreciation Expence		$ 117,554	$ 85,854	$ 4,110	$ 18,371	$ 2,916	$ 3,904	$ 1,470	$ 457	$ 473
55		Annual Carrying Charge	$	$ 228,550	$ 165,597	$ 7,929	$ 36,087	$ 5,728	$ 8,045	$ 3,028	$ 1,046	$ 1,091
56		Unit Annual Carrying Costs	$/Cust		$6.18	$6.21	$6.89	$6.89	$11.42	$11.36	$33.74	$33.05

Northern Utilities New Hampshire
2021 Rate Case Gas Marginal Cost of Service Study
O&M Expense

A No.	B FERC A/C	C Description	D Units	E Total	F Residential Heat	G Residentail Non-Heat	H High Winter Small	I Low Winter Small	J High Winter Medium	K Low Winter Medium	L High Winter Large	M Low Winter Large
1		**Customer Related O&M**										
2	902	Meter Reading Expenses										
3		Meter Reading Expenses			$ 149,729	$ 7,129	$ 29,930	$ 4,899	$ 5,111	$ 1,694	$ 1,835	$ 2,554
4		Expenses per customer			$ 5.58	$ 5.58	$ 5.72	$ 5.89	$ 7.26	$ 6.36	$ 59.18	$ 77.40
5	903	Customer Records & Collection Expenses										
6		Customer Records & Collection Expenses			$ 1,563,982	$ 74,464	$ 305,294	$ 48,496	$ 41,075	$ 15,544	$ 1,808	$ 1,925
7		Expenses per customer			$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33
8	904	Uncollectible Accounts										
9		Uncollectible Accounts			$ 368,931	$ 11,718	$ 38,990	$ 7,696	$ -	$ 8,415	$ -	$ 2,000
10		Expenses per customer			$ 13.76	$ 9.18	$ 7.45	$ 9.26	$ -	$ 31.58	$ -	$ 60.60
11	908	Customer Assistance Expenses										
12		Customer Assistance Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Expenses per customer			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	909	Informational and Instructional Advertising Exp.										
15		Informational and Instructional Advertising Exp.			$ 56,358	$ 2,683	$ 11,001	$ 1,748	$ 1,480	$ 560	$ 65	$ 69
16		Expenses per customer			$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10
17	920-935	A&G Expense - Customer Related										
18		A&G Expense - Customer Allocation			$ 3,418,714	$ 166,346	$ 849,158	$ 135,185	$ 304,929	$ 112,969	$ 50,554	$ 54,825
19		Expenses per customer			$ 127.49	$ 130.29	$ 162.23	$ 162.59	$ 432.99	$ 423.90	$ 1,630.76	$ 1,661.37
20		**Demand Related O&M**										
21	920-935	A&G Expense - Demand Related										
22		A&G Expense - Demand Allocation		$ 2,146,279	$ 760,081	$ 7,398	$ 379,125	$ 24,611	$ 531,622	$ 77,873	$ 188,679	$ 176,890
23		Expenses per unit Demand		32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36
24		**Billing Determinants**										
25		No. of Customers	count	35,192	26,815	1,277	5,234	831	704	267	31	33
26		Design Day Capacity	dt	66,317	23,486	229	11,714	760	16,426	2,406	5,830	5,466

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Northern Utilities New Hampshire
Revenue Proof and Rate Design
Test Year: January 1, 2020 Through December 31, 2020

Line No.	Rate Description	2020 Billing Units (bills or therms)	Current Rates	Calculated Revenue	Adjustments: Normalization & Annualization Adjustments (bills or therms)	Adjustments: Weather Normalization & Annualization Revenue Adjustment	Adjustments: R-10 Rate Change Annualization	Pro Forma at Current Rates: 2020 Adjusted Billing Determinants (bills or therms)	Pro Forma at Current Rates: 2020 Adjusted Base Year Revenue ("Margin")	Pro Forma Proposed Rates: Projected Billing Determinants (bills or therms)	Pro Forma Proposed Rates: Proposed Rate	Pro Forma Proposed Rates: Total Proposed Revenue ("Margin")
	(A)	(B)	(C)	(D)	(E)	(F)		(H)	(I)	(J)	(K)	(L)
				[B * C]		[C * E]		[B + E]	[D + F]	[=H]		[J * K]
1	**R-5: Residential Heating**											
2	Customer Charge	306,525	$22.20	$6,804,865	7,528	$167,116		314,053	$6,971,981	314,053	$27.84	$8,743,241
3	Summer First 50 therms	2,947,284	$0.6099	$1,797,548	148,552	$90,602		3,095,836	$1,888,150	3,095,836	$0.8491	$2,628,674
4	Summer Excess therms	459,480	$0.6099	$280,237	-	$0		459,480	$280,237	459,480	$0.8491	$390,145
5	Winter First 50 therms	6,432,280	$0.6920	$4,451,138	182,063	$125,988		6,614,343	$4,577,125	6,614,343	$0.8491	$5,616,239
6	Winter Excess therms	7,449,509	$0.6920	$5,155,060	1,986,762	$1,374,840		9,436,272	$6,529,900	9,436,272	$0.8491	$8,012,338
7	Total	17,288,553		$18,488,849	2,317,378	$1,758,545		19,605,931	$20,247,394	19,605,931		$25,390,637
8	**R-10: Residential Heating, Low Income**											
9	**January through October**											
10	Customer Charge	7,409	$8.88	$65,795	(972)	($21,587)	$98,692					
11	Summer First 50 therms	60,977	$0.2440	$14,878	(4,875)	($2,973)	$22,311					
12	Summer Excess therms	4,657	$0.2440	$1,136	-	$0	$1,704					
13	Winter First 50 therms	164,671	$0.2760	$45,449	(31,181)	($21,578)	$68,503					
14	Winter Excess therms	154,635	$0.2760	$42,679	24,940	$17,258	$64,328					
15	Total	384,939		$169,938	(11,116)	($28,879)	$255,538					
16	**November, December**											
17	Customer Charge before rate char	335	$8.88	$2,979			$4,468					
18	Customer Charge after rate chang	938	$22.20	$20,822	14	$311						
19	Summer First 50 therms b/f chang	11,932	$0.2440	$2,911	1,843	$1,124	$4,366					
20	Summer Excess therms b/f change	2,539	$0.2440	$620		$0	$929					
21	Winter First 50 therms	40,114	$0.6920	$27,759	701	$485	$0					
22	Winter Excess therms	25,775	$0.6920	$17,836	4,598	$3,182	$0					
23	Total	80,360		$72,927	7,142	$5,102	$9,763					
24	**Test Year**											
25	Customer Charge	8,683		$89,595	(958)	($21,276)	$103,160	7,724	$171,480	7,724	$27.84	$215,045
26	Summer First 50 therms	72,909		$17,790	(3,032)	($1,849)	$26,677	69,877	$42,618	69,877	$0.8491	$59,333
27	Summer Excess therms	7,196		$1,756	-	$0	$2,633	7,196	$4,389	7,196	$0.8491	$6,110
28	Winter First 50 therms	204,785		$73,208	(30,481)	($21,093)	$68,503	174,305	$120,619	174,305	$0.8491	$148,002
29	Winter Excess therms	180,409		$60,515	29,538	$20,441	$64,328	209,948	$145,284	209,948	$0.8491	$178,267
30	Total	465,300		$242,865	(3,974)	($23,777)	$265,302	461,326	$484,389	461,326		$606,756

Northern Utilities New Hampshire
Revenue Proof and Rate Design
Test Year: January 1, 2020 Through December 31, 2020

Line No.	Rate Description	2020 Billing Units (bills or therms)	Current Rates	Calculated Revenue	Adjustments: Normalization & Annualization Adjustments (bills or therms)	Adjustments: Weather Normalization & Annualization Revenue Adjustment	Adjustments: R-10 Rate Change Annualization	Pro Forma at Current Rates: 2020 Adjusted Billing Determinants (bills or therms)	Pro Forma at Current Rates: 2020 Adjusted Base Year Revenue ("Margin")	Pro Forma Proposed Rates: Projected Billing Determinants (bills or therms)	Pro Forma Proposed Rates: Proposed Rate	Pro Forma Proposed Rates: Total Proposed Revenue ("Margin")
	(A)	(B)	(C)	(D)	(E)	(F)		(H)	(I)	(J)	(K)	(L)
				[B * C]		[C * E]		[B + E]	[D + F]	[=H]		[J * K]
31	**R-6: Residential Non-Heating**											
32	Customer Charge	15,776	$22.20	$350,236	(456)	($10,123)		15,320	$340,113	15,320	$27.84	$426,520
33	Summer First 10 therms	51,805	$0.6470	$33,518	(3,321)	($2,149)		48,484	$31,369	48,484	$1.1208	$54,340
34	Summer Excess therms	32,928	$0.6470	$21,304	-	$0		32,928	$21,304	32,928	$1.1208	$36,906
35	Winter First 10 therms	52,602	$0.6470	$34,034	(599)	($388)		52,003	$33,646	52,003	$1.1208	$58,285
36	Winter Excess therms	94,282	$0.6470	$61,001	9,571	$6,193		103,854	$67,193	103,854	$1.1208	$116,399
37	Total	231,617		$500,092	5,651	($6,467)		237,269	$493,626	237,269		$692,451
38	**G-40/T-40: Low Annual, High Winter Use**											
39	Customer Charge	60,528	$75.09	$4,545,034	2,284	$171,520		62,812	$4,716,554	62,812	$80.00	$5,024,961
40	Summer First 75 therms	749,335	$0.1865	$139,751	130,670	$24,370		880,005	$164,121	880,005	$0.2518	$221,585
41	Summer Excess therms	728,589	$0.1865	$135,882	-	$0		728,589	$135,882	728,589	$0.2518	$183,459
42	Winter First 75 therms	1,918,684	$0.1865	$357,835	51,517	$9,608		1,970,201	$367,443	1,970,201	$0.2518	$496,097
43	Winter Excess therms	6,048,253	$0.1865	$1,127,999	1,253,784	$233,831		7,302,037	$1,361,830	7,302,037	$0.2518	$1,838,653
44	Total	9,444,862		$6,306,501	1,435,971	$439,328		10,880,833	$6,745,829	10,880,833		$7,764,755
45	**G-50/T-50: Low Annual, Low Winter Use**											
46	Customer Charge	9,988	$75.09	$749,978	(10)	($760)		9,978	$749,218	9,978	$80.00	$798,208
47	Summer First 75 therms	211,366	$0.1865	$39,420	(7,547)	($1,408)		203,819	$38,012	203,819	$0.2232	$45,492
48	Summer Excess therms	444,727	$0.1865	$82,942	-	$0		444,727	$82,942	444,727	$0.2232	$99,263
49	Winter First 75 therms	216,653	$0.1865	$40,406	3,516	$656		220,169	$41,061	220,169	$0.2232	$49,142
50	Winter Excess therms	601,017	$0.1865	$112,090	4,841	$903		605,858	$112,993	605,858	$0.2232	$135,228
51	Total	1,473,763		$1,024,835	810	($609)		1,474,573	$1,024,226	1,474,573		$1,127,333
52	**G-41/T-41: Medium Annual, High Winter Use**											
53	Customer Charge	8,741	$222.64	$1,946,116	(290)	($64,630)		8,451	$1,881,486	8,451	$225.00	$1,901,430
54	Summer All therms	2,627,539	$0.1895	$497,919	81,420	$15,429		2,708,960	$513,348	2,708,960	$0.2860	$774,762
55	Winter All therms	11,121,406	$0.2425	$2,696,941	593,466	$143,916		11,714,872	$2,840,856	11,714,872	$0.2860	$3,350,453
56	Total	13,748,945		$5,140,976	674,887	$94,715		14,423,832	$5,235,691	14,423,832		$6,026,646
57	**G-51/T-51: Medium Annual, Low Winter Use**											
58	Customer Charge	3,318	$222.64	$738,727	(120)	($26,725)		3,198	$712,003	3,198	$225.00	$719,550
59	Summer First 1,000 therms	1,231,175	$0.1337	$164,608	(61,835)	($8,267)		1,169,340	$156,341	1,169,340	$0.1718	$200,893
60	Summer Excess therms	515,635	$0.1087	$56,050	254,848	$27,702		770,483	$83,752	770,483	$0.1718	$132,369
61	Winter First 1,300 therms	1,677,170	$0.1712	$287,131	(75,660)	($12,953)		1,601,510	$274,178	1,601,510	$0.1718	$275,139
62	Winter Excess therms	1,045,521	$0.1399	$146,268	174,446	$24,405		1,219,967	$170,673	1,219,967	$0.1718	$209,590
63	Total	4,469,501		$1,392,785	291,799	$4,162		4,761,300	$1,396,947	4,761,300		$1,537,541

Northern Utilities New Hampshire
Revenue Proof and Rate Design
Test Year: January 1, 2020 Through December 31, 2020

					Adjustments			Pro Forma at Current Rates		Pro Forma Proposed Rates		
Line No.	Rate Description	2020 Billing Units (bills or therms)	Current Rates	Calculated Revenue	Normalization & Annualization Adjustments (bills or therms)	Weather Normalization & Annualization Revenue Adjustment	R-10 Rate Change Annualization	2020 Adjusted Billing Determinants (bills or therms)	2020 Adjusted Base Year Revenue ("Margin")	Projected Billing Determinants (bills or therms)	Proposed Rate	Total Proposed Revenue ("Margin")
	(A)	(B)	(C)	(D)	(E)	(F)		(H)	(I)	(J)	(K)	(L)
				[B * C]		[C * E]		[B + E]	[D + F]	[=H]		[J * K]
64	**G-42/T-42: High Annual, High Winter Use**											
65	Customer Charge	413	$1,335.81	$551,022	(41)	($54,100)		372	$496,921	372	$1,350.00	$502,200
66	Summer All therms	1,589,451	$0.1206	$191,688	(42,692)	($5,149)		1,546,759	$186,539	1,546,759	$0.2167	$335,183
67	Winter All therms	4,234,069	$0.1984	$840,039	108,944	$21,614		4,343,013	$861,654	4,343,013	$0.2167	$941,131
68	Total	5,823,520		$1,582,749	66,252	($37,635)		5,889,772	$1,545,114	5,889,772		$1,778,514
69	**G-52/T-52: High Annual, Low Winter Use**											
70	Customer Charge	391	$1,335.81	$521,901	5	$7,080		396	$528,981	396	$1,350.00	$534,600
71	Summer All therms	7,827,306	$0.0792	$619,923	29,672	$2,350		7,856,979	$622,273	7,856,979	$0.1121	$880,767
72	Winter All therms	8,356,912	$0.1720	$1,437,389	203,384	$34,982		8,560,295	$1,472,371	8,560,295	$0.1720	$1,472,371
73	Total	16,184,218		$2,579,212	233,061	$44,412		16,417,274	$2,623,624	16,417,274		$2,887,738
74	**Total**											
75	Customer Charge	414,362		$16,297,475	7,942	$168,102	$103,160	422,304	$16,568,737	422,304		$18,865,756
76	Summer First Block therms	17,308,170		$3,502,164	271,888	$113,930	$26,677	17,580,058	$3,642,771	17,580,058		$5,201,030
77	Summer Excess therms	2,188,556		$578,170	254,848	$27,702	$2,633	2,443,404	$608,505	2,443,404		$848,251
78	Winter First Block therms	34,214,561		$10,218,121	1,036,150	$302,330	$68,503	35,250,711	$10,588,954	35,250,711		$12,406,859
79	Winter Excess therms	15,418,993		$6,662,934	3,458,944	$1,660,611	$64,328	18,877,936	$8,387,873	18,877,936		$10,490,475
80	Total	69,130,280		$37,258,864	5,021,830	$2,272,675	$265,302	74,152,109	$39,796,840	74,152,109		$47,812,371

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Northern Utilities New Hampshire
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
				Billing Determinants		Bill Cycle to Calendar Month Conversion			Calendar Month Therms			Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Pro Forma Test Year Normal Therms (Cycle)	Days In Bill Cycle	Days Billed in Current Month	% Calendar Therms Billed in Same Month	Therms Billed in Same Month	Therms Billed in Next Month	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
1	R-5	Residential Heating	January	26,171	3,484,177	31.0	15.0	48.4%	1,685,892	1,883,263	3,569,155	$ 3,759,173	$ 143.64
2			February	26,171	3,648,821	31.0	15.0	48.4%	1,765,559	1,401,584	3,167,143	$ 3,417,824	$ 130.60
3		*Rates*	March	26,171	3,018,796	28.0	15.0	53.6%	1,617,212	1,051,289	2,668,501	$ 2,994,428	$ 114.42
4		*Customer*	April	26,171	2,036,872	31.0	15.0	48.4%	985,583	580,633	1,566,216	$ 2,058,477	$ 78.65
5		*$27.84*	May	26,171	1,161,265	30.0	15.0	50.0%	580,633	345,556	926,189	$ 1,515,030	$ 57.89
6		*Per Therm*	June	26,171	669,515	31.0	15.0	48.4%	323,959	147,794	471,753	$ 1,129,169	$ 43.15
7		*$0.8491*	July	26,171	295,589	30.0	15.0	50.0%	147,794	126,922	274,716	$ 961,865	$ 36.75
8			August	26,171	245,912	31.0	15.0	48.4%	118,989	184,742	303,731	$ 986,501	$ 37.69
9			September	26,171	357,937	31.0	15.0	48.4%	173,195	346,024	519,219	$ 1,169,472	$ 44.69
10			October	26,171	692,048	30.0	15.0	50.0%	346,024	701,831	1,047,855	$ 1,618,337	$ 61.84
11			November	26,171	1,359,798	31.0	15.0	48.4%	657,967	1,317,601	1,975,568	$ 2,406,058	$ 91.94
12			December	26,171	2,635,202	30.0	15.0	50.0%	1,317,601	1,798,285	3,115,886	$ 3,374,302	$ 128.93
13					19,605,931	365.0	180.00				19,605,931	$ 25,390,637	$ 970.18
14	R-10	Res. Heating, Low Income	January	644	78,003	31.0	15.0	48.4%	37,744	43,245	80,989	$ 86,688	$ 134.67
15			February	644	83,787	31.0	15.0	48.4%	40,542	34,528	75,070	$ 81,663	$ 126.87
16		*Rates*	March	644	74,368	28.0	15.0	53.6%	39,840	27,318	67,158	$ 74,945	$ 116.43
17		*Customer*	April	644	52,929	31.0	15.0	48.4%	25,611	15,074	40,685	$ 52,466	$ 81.51
18		*$27.84*	May	644	30,149	30.0	15.0	50.0%	15,074	8,641	23,715	$ 38,057	$ 59.12
19		*Per Therm*	June	644	16,742	31.0	15.0	48.4%	8,101	3,326	11,427	$ 27,623	$ 42.91
20		*$0.8491*	July	644	6,653	30.0	15.0	50.0%	3,326	2,780	6,106	$ 23,105	$ 35.89
21			August	644	5,386	31.0	15.0	48.4%	2,606	4,279	6,885	$ 23,767	$ 36.92
22			September	644	8,291	31.0	15.0	48.4%	4,012	8,757	12,769	$ 28,763	$ 44.68
23			October	644	17,515	30.0	15.0	50.0%	8,757	16,518	25,275	$ 39,382	$ 61.18
24			November	644	32,003	31.0	15.0	48.4%	15,485	27,750	43,235	$ 54,631	$ 84.87
25			December	644	55,499	30.0	15.0	50.0%	27,750	40,260	68,009	$ 75,667	$ 117.55
26					461,326	365.0	180.00				461,326	$ 606,756	$ 942.62
27	R-6	Residential Non-Heating	January	1,277	32,194	31.0	15.0	48.4%	15,578	16,869	32,447	$ 71,910	$ 56.32
28			February	1,277	32,684	31.0	15.0	48.4%	15,815	12,513	28,328	$ 67,293	$ 52.71
29		*Rates*	March	1,277	26,950	28.0	15.0	53.6%	14,438	10,792	25,230	$ 63,821	$ 49.99
30		*Customer*	April	1,277	20,909	31.0	15.0	48.4%	10,117	8,733	18,851	$ 56,671	$ 44.39
31		*$27.84*	May	1,277	17,467	30.0	15.0	50.0%	8,733	7,508	16,241	$ 53,747	$ 42.10
32		*Per Therm*	June	1,277	14,547	31.0	15.0	48.4%	7,039	5,794	12,833	$ 49,926	$ 39.11
33		*$1.1208*	July	1,277	11,588	30.0	15.0	50.0%	5,794	5,514	11,308	$ 48,217	$ 37.77
34			August	1,277	10,683	31.0	15.0	48.4%	5,169	6,395	11,564	$ 48,504	$ 37.99
35			September	1,277	12,390	31.0	15.0	48.4%	5,995	6,786	12,781	$ 49,868	$ 39.06
36			October	1,277	13,571	30.0	15.0	50.0%	6,786	9,033	15,819	$ 53,273	$ 41.73
37			November	1,277	17,502	31.0	15.0	48.4%	8,469	13,391	21,860	$ 60,044	$ 47.03
38			December	1,277	26,783	30.0	15.0	50.0%	13,391	16,616	30,008	$ 69,176	$ 54.18
39					237,269	365.0	180.00				237,269	$ 692,451	$ 542.38

Northern Utilities New Hampshire
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
				Billing Determinants		Bill Cycle to Calendar Month Conversion			Calendar Month Therms			Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Pro Forma Test Year Normal Therms (Cycle)	Days In Bill Cycle	Days Billed in Current Month	% Calendar Therms Billed in Same Month	Therms Billed in Same Month	Therms Billed in Next Month	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
40	G-40/T-40	Low Annual, High Winter	January	5,234	2,074,220	31.0	15.00	48.4%	1,003,655	1,102,188	2,105,842	$ 948,998	$ 181.30
41			February	5,234	2,135,489	31.0	15.00	48.4%	1,033,301	819,847	1,853,148	$ 885,369	$ 169.15
42		*Rates*	March	5,234	1,765,824	28.0	15.00	53.6%	945,977	584,542	1,530,519	$ 804,131	$ 153.63
43		*Customer*	April	5,234	1,132,550	31.0	15.00	48.4%	548,008	307,957	855,965	$ 634,279	$ 121.18
44		*$80.00*	May	5,234	615,915	30.0	15.00	50.0%	307,957	160,450	468,408	$ 536,692	$ 102.53
45		*Per Therm*	June	5,234	310,873	31.0	15.00	48.4%	150,422	43,109	193,531	$ 467,478	$ 89.31
46		*$0.2518*	July	5,234	86,217	30.0	15.00	50.0%	43,109	31,705	74,813	$ 437,585	$ 83.60
47			August	5,234	61,428	31.0	15.00	48.4%	29,723	62,259	91,982	$ 441,908	$ 84.42
48			September	5,234	120,626	31.0	15.00	48.4%	58,368	167,906	226,274	$ 475,722	$ 90.89
49			October	5,234	335,813	30.0	15.00	50.0%	167,906	381,182	549,088	$ 557,007	$ 106.41
50			November	5,234	738,541	31.0	15.00	48.4%	357,358	751,669	1,109,028	$ 698,000	$ 133.35
51			December	5,234	1,503,339	30.0	15.00	50.0%	751,669	1,070,565	1,822,234	$ 877,585	$ 167.66
52					10,880,833	365.0	180.00				10,880,833	$ 7,764,755	$ 1,483.43
53	G-50/T-50	Low Annual, Low Winter	January	831	166,567	31.0	15.00	48.4%	80,597	85,181	165,778	$ 103,519	$ 124.50
54			February	831	165,038	31.0	15.00	48.4%	79,857	73,369	153,226	$ 100,717	$ 121.13
55		*Rates*	March	831	158,026	28.0	15.00	53.6%	84,657	51,270	135,926	$ 96,856	$ 116.49
56		*Customer*	April	831	99,335	31.0	15.00	48.4%	48,065	45,655	93,720	$ 87,436	$ 105.16
57		*$80.00*	May	831	91,310	30.0	15.00	50.0%	45,655	51,347	97,002	$ 88,168	$ 106.04
58		*Per Therm*	June	831	99,485	31.0	15.00	48.4%	48,138	53,475	101,613	$ 89,197	$ 107.28
59		*$0.2232*	July	831	106,951	30.0	15.00	50.0%	53,475	53,647	107,123	$ 90,427	$ 108.76
60			August	831	103,942	31.0	15.00	48.4%	50,294	64,058	114,352	$ 92,041	$ 110.70
61			September	831	124,112	31.0	15.00	48.4%	60,054	51,191	111,245	$ 91,347	$ 109.86
62			October	831	102,382	30.0	15.00	50.0%	51,191	59,985	111,176	$ 91,332	$ 109.84
63			November	831	116,220	31.0	15.00	48.4%	56,236	70,603	126,839	$ 94,828	$ 114.05
64			December	831	141,206	30.0	15.00	50.0%	70,603	85,970	156,573	$ 101,464	$ 122.03
65					1,474,573	365.0	180.00				1,474,573	$ 1,127,333	$ 1,355.84
66	G-41/T-41	Med. Annual, High Winter	January	704	2,542,501	31.0	15.00	48.4%	1,230,243	1,342,852	2,573,095	$ 894,358	$ 1,269.97
67			February	704	2,601,776	31.0	15.00	48.4%	1,258,924	1,026,886	2,285,810	$ 812,194	$ 1,153.30
68		*Rates*	March	704	2,211,754	28.0	15.00	53.6%	1,184,868	739,200	1,924,069	$ 708,736	$ 1,006.39
69		*Customer*	April	704	1,432,201	31.0	15.00	48.4%	693,000	428,559	1,121,559	$ 479,218	$ 680.48
70		*$225.00*	May	704	857,118	30.0	15.00	50.0%	428,559	260,143	688,701	$ 355,421	$ 504.69
71		*Per Therm*	June	704	504,026	31.0	15.00	48.4%	243,884	116,954	360,838	$ 261,652	$ 371.54
72		*$0.2860*	July	704	233,908	30.0	15.00	50.0%	116,954	101,623	218,577	$ 220,966	$ 313.77
73			August	704	196,895	31.0	15.00	48.4%	95,272	144,324	239,596	$ 226,977	$ 322.30
74			September	704	279,628	31.0	15.00	48.4%	135,304	258,880	394,184	$ 271,189	$ 385.08
75			October	704	517,761	30.0	15.00	50.0%	258,880	570,478	829,358	$ 395,649	$ 561.82
76			November	704	1,105,301	31.0	15.00	48.4%	534,823	970,482	1,505,305	$ 588,970	$ 836.33
77			December	704	1,940,963	30.0	15.00	50.0%	970,482	1,312,259	2,282,740	$ 811,316	$ 1,152.06
78					14,423,832	365.0	180.00				14,423,832	$ 6,026,646	$ 8,557.74

Northern Utilities New Hampshire
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
				Billing Determinants		Bill Cycle to Calendar Month Conversion			Calendar Month Therms			Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Pro Forma Test Year Normal Therms (Cycle)	Days In Bill Cycle	Days Billed in Current Month	% Calendar Therms Billed in Same Month	Therms Billed in Same Month	Therms Billed in Next Month	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
79	G-51/T-51	Med. Annual, Low Winter	January	267	543,661	31.0	15.00	48.4%	263,062	285,547	548,609	$ 154,213	$ 578.66
80			February	267	553,247	31.0	15.00	48.4%	267,700	238,585	506,285	$ 146,942	$ 551.38
81		*Rates*	March	267	513,874	28.0	15.00	53.6%	275,290	204,221	479,510	$ 142,342	$ 534.12
82		*Customer*	April	267	395,677	31.0	15.00	48.4%	191,457	177,978	369,435	$ 123,431	$ 463.16
83		*$225.00*	May	267	355,957	30.0	15.00	50.0%	177,978	174,313	352,292	$ 120,486	$ 452.11
84		*Per Therm*	June	267	337,732	31.0	15.00	48.4%	163,419	151,004	314,422	$ 113,980	$ 427.69
85		*$0.1718*	July	267	302,008	30.0	15.00	50.0%	151,004	145,606	296,610	$ 110,920	$ 416.21
86			August	267	282,112	31.0	15.00	48.4%	136,506	163,666	300,172	$ 111,532	$ 418.51
87			September	267	317,102	31.0	15.00	48.4%	153,437	152,861	306,298	$ 112,585	$ 422.46
88			October	267	305,723	30.0	15.00	50.0%	152,861	195,057	347,918	$ 119,735	$ 449.29
89			November	267	377,923	31.0	15.00	48.4%	182,866	238,142	421,008	$ 132,292	$ 496.40
90			December	267	476,284	30.0	15.00	50.0%	238,142	280,599	518,741	$ 149,082	$ 559.41
91					4,761,300	365.0	180.00				4,761,300	$ 1,537,541	$ 5,769.39
92	G-42/T-42	High Annual, High Winter	January	31	915,167	31.00	31.00	100.0%	915,167	-	915,167	$ 240,167	$ 7,747.32
93			February	31	819,517	28.00	28.00	100.0%	819,517	-	819,517	$ 219,439	$ 7,078.69
94		*Rates*	March	31	734,670	31.00	31.00	100.0%	734,670	-	734,670	$ 201,053	$ 6,485.58
95		*Customer*	April	31	515,218	30.00	30.00	100.0%	515,218	-	515,218	$ 153,498	$ 4,951.54
96		*$1,350.00*	May	31	324,350	31.00	31.00	100.0%	324,350	-	324,350	$ 112,137	$ 3,617.31
97		*Per Therm*	June	31	218,129	30.00	30.00	100.0%	218,129	-	218,129	$ 89,118	$ 2,874.79
98		*$0.2167*	July	31	189,460	31.00	31.00	100.0%	189,460	-	189,460	$ 82,906	$ 2,674.38
99			August	31	192,134	31.00	31.00	100.0%	192,134	-	192,134	$ 83,485	$ 2,693.08
100			September	31	232,113	30.00	30.00	100.0%	232,113	-	232,113	$ 92,149	$ 2,972.54
101			October	31	383,712	31.00	31.00	100.0%	383,712	-	383,712	$ 125,000	$ 4,032.27
102			November	31	578,379	30.00	30.00	100.0%	578,379	-	578,379	$ 167,185	$ 5,393.06
103			December	31	786,923	31.00	31.00	100.0%	786,923	-	786,923	$ 212,376	$ 6,850.84
104					5,889,772	365.0	365.00				5,889,772	$ 1,778,514	$ 57,371.41
105	G-52/T-52	High Annual, Low Winter	January	33	1,332,981	31.00	31.00	100.0%	1,332,981	-	1,332,981	$ 273,823	$ 8,297.66
106			February	33	1,504,043	28.00	28.00	100.0%	1,504,043	-	1,504,043	$ 303,245	$ 9,189.26
107		*Rates*	March	33	1,376,235	31.00	31.00	100.0%	1,376,235	-	1,376,235	$ 281,262	$ 8,523.10
108		*Customer*	April	33	1,383,288	30.00	30.00	100.0%	1,383,288	-	1,383,288	$ 280,018	$ 8,485.41
109		*$1,350.00*	May	33	1,262,689	31.00	31.00	100.0%	1,262,689	-	1,262,689	$ 186,436	$ 5,649.57
110		*Per Therm Summer*	June	33	1,236,219	30.00	30.00	100.0%	1,236,219	-	1,236,219	$ 183,877	$ 5,572.02
111		*$0.1121*	July	33	1,220,236	31.00	31.00	100.0%	1,220,236	-	1,220,236	$ 181,339	$ 5,495.11
112		*Per Therm Winter*	August	33	1,282,733	31.00	31.00	100.0%	1,282,733	-	1,282,733	$ 188,344	$ 5,707.41
113		*$0.1720*	September	33	1,416,119	30.00	30.00	100.0%	1,416,119	-	1,416,119	$ 203,297	$ 6,160.51
114			October	33	1,430,639	31.00	31.00	100.0%	1,430,639	-	1,430,639	$ 207,514	$ 6,288.30
115			November	33	1,409,953	30.00	30.00	100.0%	1,409,953	-	1,409,953	$ 285,345	$ 8,646.81
116			December	33	1,562,138	31.00	31.00	100.0%	1,562,138	-	1,562,138	$ 313,238	$ 9,492.05
117					16,417,274	365.0	365.00				16,417,274	$ 2,887,738	$ 87,507.22
118		**Test Year Total**			74,152,109						74,152,109	$ 47,812,371	

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Northern Utilities - NH Division
Residential Heating Customer - R5
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	5.91	$31.26	$37.72	$6.46	20.7%
20.0%	22.05	$56.01	$64.73	$8.71	15.6%
30.0%	37.57	$79.81	$90.68	$10.88	13.6%
40.0%	52.37	$102.51	$115.44	$12.94	12.6%
50.0%	67.18	$125.22	$140.22	$15.00	12.0%
60.0%	82.99	$149.46	$166.66	$17.21	11.5%
70.0%	101.23	$177.42	$197.17	$19.75	11.1%
80.0%	124.00	$212.35	$235.27	$22.92	10.8%
90.0%	155.63	$260.84	$288.17	$27.33	10.5%
100.0%	240.82	$391.47	$430.66	$39.20	10.0%
Average	88.98	$158.63	$176.67	$18.04	11.4%
		Distribution Only			
10.0%	5.91	$26.29	$32.86	$6.57	25.0%
20.0%	22.05	$37.46	$46.56	$9.10	24.3%
30.0%	37.57	$48.20	$59.74	$11.54	23.9%
40.0%	52.37	$58.44	$72.31	$13.87	23.7%
50.0%	67.18	$68.69	$84.88	$16.19	23.6%
60.0%	82.99	$79.63	$98.31	$18.68	23.5%
70.0%	101.23	$92.25	$113.79	$21.54	23.4%
80.0%	124.00	$108.01	$133.13	$25.12	23.3%
90.0%	155.63	$129.90	$159.99	$30.09	23.2%
100.0%	240.82	$188.84	$232.32	$43.47	23.0%
Average	88.98	$83.77	$103.39	$19.62	23.4%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 50 therms ($/thm)	$0.6920	(1)	Distribution Charge - All therms ($/thm)	$0.8491	(3)
Distribution Charge - Excess 50 therms ($/thm)	$0.6920	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.7315	(2)	COGC ($/thm)	$0.7271	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
Residential Heating Customer - R5
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	1.76	$24.13	$30.16	$6.04	25.0%
30.0%	5.79	$28.53	$35.48	$6.95	24.4%
40.0%	9.28	$32.34	$40.07	$7.74	23.9%
50.0%	12.82	$36.20	$44.74	$8.54	23.6%
60.0%	16.63	$40.36	$49.76	$9.40	23.3%
70.0%	21.15	$45.30	$55.72	$10.42	23.0%
80.0%	27.57	$52.31	$64.18	$11.87	22.7%
90.0%	39.21	$65.02	$79.53	$14.51	22.3%
100.0%	83.07	$112.92	$137.35	$24.42	21.6%
Average	21.73	$45.93	$56.48	$10.55	23.0%
		Distribution Only			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	1.76	$23.28	$29.34	$6.06	26.0%
30.0%	5.79	$25.73	$32.76	$7.03	27.3%
40.0%	9.28	$27.86	$35.72	$7.86	28.2%
50.0%	12.82	$30.02	$38.72	$8.71	29.0%
60.0%	16.63	$32.34	$41.96	$9.62	29.7%
70.0%	21.15	$35.10	$45.80	$10.70	30.5%
80.0%	27.57	$39.01	$51.25	$12.23	31.4%
90.0%	39.21	$46.11	$61.13	$15.02	32.6%
100.0%	83.07	$72.86	$98.37	$25.51	35.0%
Average	21.73	$35.45	$46.29	$10.84	30.6%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 50 therms ($/thm)	$0.6099	(1)	Distribution Charge - All therms ($/thm)	$0.8491	(3)
Distribution Charge - Excess 50 therms ($/thm)	$0.6099	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.3724	(2)	COGC ($/thm)	$0.3727	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
Residential Low Income Heating Customer - R10
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Present Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	14.96	$25.57	$29.71	$4.14	16.2%
20.0%	31.25	$40.13	$45.40	$5.27	13.1%
30.0%	43.22	$50.82	$56.92	$6.10	12.0%
40.0%	54.61	$61.00	$67.89	$6.89	11.3%
50.0%	65.94	$71.12	$78.79	$7.67	10.8%
60.0%	77.14	$81.13	$89.58	$8.45	10.4%
70.0%	90.21	$92.81	$102.16	$9.36	10.1%
80.0%	108.11	$108.80	$119.40	$10.60	9.7%
90.0%	135.38	$133.16	$145.65	$12.49	9.4%
100.0%	205.88	$196.15	$213.53	$17.38	8.9%
Average	82.67	$86.07	$94.90	$8.83	10.3%
		Distribution Only			
10.0%	14.96	$32.55	$40.54	$7.99	24.5%
20.0%	31.25	$43.83	$54.38	$10.55	24.1%
30.0%	43.22	$52.11	$64.54	$12.43	23.9%
40.0%	54.61	$59.99	$74.21	$14.22	23.7%
50.0%	65.94	$67.83	$83.83	$16.00	23.6%
60.0%	77.14	$75.58	$93.34	$17.76	23.5%
70.0%	90.21	$84.63	$104.44	$19.81	23.4%
80.0%	108.11	$97.02	$119.64	$22.62	23.3%
90.0%	135.38	$115.89	$142.80	$26.91	23.2%
100.0%	205.88	$164.67	$202.66	$37.98	23.1%
Average	82.67	$79.41	$98.04	$18.63	23.5%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 50 therms ($/thm)	$0.6920	(1)	Distribution Charge - All therms ($/thm)	$0.8491	(3)
Distribution Charge - Excess 50 therms ($/thm)	$0.6920	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.7315	(2)	COGC ($/thm)	$0.7271	(5)
45% Customer Charge Discount ($/customer)	-$9.99	(6)	45% Customer Charge Discount ($/customer)	-$12.53	(6)
45% Therm Discount - First 50 therms ($/thm)	-$0.6400	(6)	45% Therm Discount - All therms ($/thm)	-$0.7100	(6)
45% Therm Discount - Excess 50 therms ($/thm)	-$0.6400	(6)			

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal
(6) Low income customers receive a 45% discount on the customer charge, distribution charges, and COG in the winter period only

Northern Utilities - NH Division
Residential Low Income Heating Customer - R10
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Present Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.15	$22.36	$28.03	$5.67	25.4%
20.0%	3.16	$25.65	$32.01	$6.35	24.8%
30.0%	6.95	$29.79	$37.00	$7.21	24.2%
40.0%	10.00	$33.12	$41.02	$7.90	23.9%
50.0%	12.74	$36.11	$44.63	$8.52	23.6%
60.0%	16.06	$39.74	$49.01	$9.27	23.3%
70.0%	20.58	$44.67	$54.96	$10.29	23.0%
80.0%	27.06	$51.76	$63.52	$11.76	22.7%
90.0%	39.85	$65.72	$80.37	$14.65	22.3%
100.0%	80.33	$109.94	$133.74	$23.81	21.7%
Average	21.69	$45.89	$56.43	$10.54	23.0%
		Distribution Only			
10.0%	0.15	$22.29	$27.97	$5.68	25.5%
20.0%	3.16	$24.13	$30.52	$6.40	26.5%
30.0%	6.95	$26.44	$33.74	$7.30	27.6%
40.0%	10.00	$28.30	$36.33	$8.03	28.4%
50.0%	12.74	$29.97	$38.66	$8.69	29.0%
60.0%	16.06	$31.99	$41.47	$9.48	29.6%
70.0%	20.58	$34.75	$45.31	$10.56	30.4%
80.0%	27.06	$38.71	$50.82	$12.11	31.3%
90.0%	39.85	$46.50	$61.68	$15.17	32.6%
100.0%	80.33	$71.19	$96.05	$24.86	34.9%
Average	21.69	$35.43	$46.25	$10.83	30.6%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 50 therms ($/thm)	$0.6099	(1)	Distribution Charge - All therms ($/thm)	$0.8491	(3)
Distribution Charge - Excess 50 therms ($/thm)	$0.6099	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.3724	(2)	COGC ($/thm)	$0.3727	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
Residential Non-Heating Customer - R6
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Present Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	0.50	$22.95	$28.81	$5.87	25.6%
30.0%	2.23	$25.53	$32.19	$6.66	26.1%
40.0%	5.44	$30.30	$38.43	$8.12	26.8%
50.0%	9.21	$35.91	$45.76	$9.84	27.4%
60.0%	12.95	$41.48	$53.03	$11.55	27.8%
70.0%	17.13	$47.70	$61.15	$13.45	28.2%
80.0%	23.24	$56.79	$73.02	$16.24	28.6%
90.0%	36.13	$75.98	$98.09	$22.12	29.1%
100.0%	78.37	$138.84	$180.22	$41.38	29.8%
Average	18.52	$49.77	$63.85	$14.09	28.3%
		Distribution Only			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	0.50	$22.52	$28.40	$5.88	26.1%
30.0%	2.23	$23.65	$30.34	$6.70	28.3%
40.0%	5.44	$25.72	$33.94	$8.22	32.0%
50.0%	9.21	$28.16	$38.17	$10.01	35.5%
60.0%	12.95	$30.58	$42.36	$11.78	38.5%
70.0%	17.13	$33.28	$47.04	$13.76	41.3%
80.0%	23.24	$37.23	$53.88	$16.65	44.7%
90.0%	36.13	$45.58	$68.33	$22.76	49.9%
100.0%	78.37	$72.90	$115.67	$42.77	58.7%
Average	18.52	$34.18	$48.60	$14.42	42.2%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 10 therms ($/thm)	$0.6470	(1)	Distribution Charge - All therms ($/thm)	$1.1208	(3)
Distribution Charge - Excess 10 therms ($/thm)	$0.6470	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.7315	(2)	COGC ($/thm)	$0.7271	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
Residential Non-Heating Customer - R6
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Present Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	0.70	$22.99	$28.95	$5.96	25.9%
30.0%	1.96	$24.41	$30.96	$6.54	26.8%
40.0%	3.94	$26.65	$34.11	$7.46	28.0%
50.0%	6.31	$29.32	$37.87	$8.55	29.1%
60.0%	8.51	$31.81	$41.37	$9.56	30.1%
70.0%	10.84	$34.45	$45.08	$10.64	30.9%
80.0%	13.60	$37.55	$49.46	$11.90	31.7%
90.0%	17.92	$42.44	$56.34	$13.90	32.7%
100.0%	37.81	$64.90	$87.96	$23.06	35.5%
Average	10.16	$33.67	$43.99	$10.32	30.7%
		Distribution Only			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	0.70	$22.65	$28.62	$5.97	26.4%
30.0%	1.96	$23.47	$30.04	$6.57	28.0%
40.0%	3.94	$24.75	$32.26	$7.51	30.3%
50.0%	6.31	$26.28	$34.91	$8.63	32.8%
60.0%	8.51	$27.70	$37.38	$9.67	34.9%
70.0%	10.84	$29.22	$39.99	$10.78	36.9%
80.0%	13.60	$31.00	$43.08	$12.08	39.0%
90.0%	17.92	$33.80	$47.93	$14.13	41.8%
100.0%	37.81	$46.66	$70.22	$23.55	50.5%
Average	10.16	$28.77	$39.23	$10.45	36.3%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 10 therms ($/thm)	$0.6470	(1)	Distribution Charge - All therms ($/thm)	$1.1208	(3)
Distribution Charge - Excess 10 therms ($/thm)	$0.6470	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.3724	(2)	COGC ($/thm)	$0.3727	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Low Annual, High Winter Use - G40
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	5.08	$80.05	$85.25	$5.20	6.5%
20.0%	29.08	$103.52	$110.09	$6.57	6.3%
30.0%	58.36	$132.13	$140.38	$8.24	6.2%
40.0%	91.27	$164.29	$174.42	$10.12	6.2%
50.0%	132.07	$204.17	$216.63	$12.45	6.1%
60.0%	183.41	$254.36	$269.75	$15.39	6.0%
70.0%	248.65	$318.12	$337.24	$19.11	6.0%
80.0%	341.54	$408.91	$433.33	$24.42	6.0%
90.0%	491.01	$555.01	$587.97	$32.96	5.9%
100.0%	989.61	$1,042.33	$1,103.78	$61.44	5.9%
Average	257.01	$326.29	$345.88	$19.59	6.0%
		Distribution Only			
10.0%	5.08	$76.04	$81.28	$5.24	6.9%
20.0%	29.08	$80.51	$87.32	$6.81	8.5%
30.0%	58.36	$85.97	$94.70	$8.72	10.1%
40.0%	91.27	$92.11	$102.98	$10.87	11.8%
50.0%	132.07	$99.72	$113.25	$13.53	13.6%
60.0%	183.41	$109.30	$126.18	$16.89	15.5%
70.0%	248.65	$121.46	$142.61	$21.15	17.4%
80.0%	341.54	$138.79	$166.00	$27.21	19.6%
90.0%	491.01	$166.66	$203.64	$36.97	22.2%
100.0%	989.61	$259.65	$329.18	$69.53	26.8%
Average	257.01	$123.02	$144.71	$21.69	17.6%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$75.09	(1)	Customer Charge ($/customer)	$80.00	(3)
Distribution Charge - First 75 therms ($/thm)	$0.1865	(1)	Distribution Charge - All therms ($/thm)	$0.2518	(3)
Distribution Charge - Excess 75 therms ($/thm)	$0.1865	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.7437	(2)	COGC ($/thm)	$0.7393	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Low Annual, High Winter Use - G40
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	0.00	$75.09	$80.00	$4.91	6.5%
30.0%	0.00	$75.09	$80.00	$4.91	6.5%
40.0%	1.02	$75.74	$80.71	$4.97	6.6%
50.0%	5.22	$78.43	$83.66	$5.23	6.7%
60.0%	11.96	$82.74	$88.39	$5.65	6.8%
70.0%	25.29	$91.26	$97.74	$6.47	7.1%
80.0%	49.28	$106.61	$114.56	$7.96	7.5%
90.0%	93.76	$135.05	$145.76	$10.70	7.9%
100.0%	280.68	$254.59	$276.85	$22.26	8.7%
Average	46.72	$104.97	$112.77	$7.80	7.4%
		Distribution Only			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	0.00	$75.09	$80.00	$4.91	6.5%
30.0%	0.00	$75.09	$80.00	$4.91	6.5%
40.0%	1.02	$75.28	$80.26	$4.98	6.6%
50.0%	5.22	$76.06	$81.32	$5.25	6.9%
60.0%	11.96	$77.32	$83.01	$5.69	7.4%
70.0%	25.29	$79.81	$86.37	$6.56	8.2%
80.0%	49.28	$84.28	$92.41	$8.13	9.6%
90.0%	93.76	$92.58	$103.61	$11.03	11.9%
100.0%	280.68	$127.44	$150.68	$23.24	18.2%
Average	46.72	$83.80	$91.76	$7.96	9.5%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$75.09	(1)	Customer Charge ($/customer)	$80.00	(3)
Distribution Charge - First 75 therms ($/thm)	$0.1865	(1)	Distribution Charge - All therms ($/thm)	$0.2518	(3)
Distribution Charge - Excess 75 therms ($/thm)	$0.1865	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.4058	(2)	COGC ($/thm)	$0.4061	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Low Annual, Low Winter Use - G50
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	1.04	$76.00	$80.94	$4.94	6.5%
30.0%	6.81	$81.08	$86.19	$5.10	6.3%
40.0%	17.70	$90.67	$96.09	$5.42	6.0%
50.0%	40.86	$111.05	$117.13	$6.08	5.5%
60.0%	78.30	$144.01	$151.15	$7.14	5.0%
70.0%	146.37	$203.92	$213.01	$9.09	4.5%
80.0%	259.74	$303.72	$316.04	$12.32	4.1%
90.0%	406.53	$432.91	$449.42	$16.51	3.8%
100.0%	704.50	$695.19	$720.20	$25.01	3.6%
Average	166.18	$221.37	$231.02	$9.65	4.4%
		Distribution Only			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	1.04	$75.28	$80.23	$4.95	6.6%
30.0%	6.81	$76.36	$81.52	$5.16	6.8%
40.0%	17.70	$78.39	$83.95	$5.56	7.1%
50.0%	40.86	$82.71	$89.12	$6.41	7.7%
60.0%	78.30	$89.69	$97.48	$7.78	8.7%
70.0%	146.37	$102.39	$112.67	$10.28	10.0%
80.0%	259.74	$123.53	$137.97	$14.44	11.7%
90.0%	406.53	$150.91	$170.74	$19.83	13.1%
100.0%	704.50	$206.48	$237.25	$30.77	14.9%
Average	166.18	$106.08	$117.09	$11.01	10.4%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$75.09	(1)	Customer Charge ($/customer)	$80.00	(3)
Distribution Charge - First 75 therms ($/thm)	$0.1865	(1)	Distribution Charge - All therms ($/thm)	$0.2232	(3)
Distribution Charge - Excess 75 therms ($/thm)	$0.1865	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.6465	(2)	COGC ($/thm)	$0.6421	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Low Annual, Low Winter Use - G50
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	0.81	$75.55	$80.48	$4.94	6.5%
30.0%	5.32	$78.10	$83.19	$5.09	6.5%
40.0%	12.20	$82.00	$87.31	$5.32	6.5%
50.0%	26.67	$90.20	$95.99	$5.80	6.4%
60.0%	55.97	$106.79	$113.56	$6.77	6.3%
70.0%	110.70	$137.79	$146.37	$8.59	6.2%
80.0%	196.19	$186.20	$197.63	$11.42	6.1%
90.0%	306.05	$248.43	$263.50	$15.07	6.1%
100.0%	521.36	$370.37	$392.59	$22.22	6.0%
Average	123.53	$145.05	$154.06	$9.01	6.2%
		Distribution Only			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	0.81	$75.24	$80.18	$4.94	6.6%
30.0%	5.32	$76.08	$81.19	$5.11	6.7%
40.0%	12.20	$77.37	$82.72	$5.36	6.9%
50.0%	26.67	$80.06	$85.95	$5.89	7.4%
60.0%	55.97	$85.53	$92.49	$6.96	8.1%
70.0%	110.70	$95.74	$104.71	$8.97	9.4%
80.0%	196.19	$111.68	$123.79	$12.11	10.8%
90.0%	306.05	$132.17	$148.31	$16.14	12.2%
100.0%	521.36	$172.32	$196.37	$24.04	14.0%
Average	123.53	$98.13	$107.57	$9.44	9.6%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$75.09	(1)	Customer Charge ($/customer)	$80.00	(3)
Distribution Charge - First 75 therms ($/thm)	$0.1865	(1)	Distribution Charge - All therms ($/thm)	$0.2232	(3)
Distribution Charge - Excess 75 therms ($/thm)	$0.1865	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.3327	(2)	COGC ($/thm)	$0.3330	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Medium Annual, High Winter Use - G41
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	410.78	$647.14	$664.01	$16.87	2.6%
20.0%	855.12	$1,106.32	$1,138.89	$32.57	2.9%
30.0%	1,123.60	$1,383.76	$1,425.82	$42.05	3.0%
40.0%	1,358.83	$1,626.86	$1,677.22	$50.36	3.1%
50.0%	1,592.36	$1,868.19	$1,926.80	$58.61	3.1%
60.0%	1,899.01	$2,185.08	$2,254.53	$69.45	3.2%
70.0%	2,385.06	$2,687.36	$2,773.97	$86.62	3.2%
80.0%	3,120.90	$3,447.78	$3,560.39	$112.61	3.3%
90.0%	4,464.86	$4,836.63	$4,996.72	$160.09	3.3%
100.0%	8,063.23	$8,555.18	$8,842.39	$287.21	3.4%
Average	2,527.37	$2,834.43	$2,926.07	$91.64	3.2%
		Distribution Only			
10.0%	410.78	$322.25	$342.48	$20.23	6.3%
20.0%	855.12	$430.01	$469.56	$39.56	9.2%
30.0%	1,123.60	$495.11	$546.35	$51.24	10.3%
40.0%	1,358.83	$552.16	$613.63	$61.47	11.1%
50.0%	1,592.36	$608.79	$680.42	$71.63	11.8%
60.0%	1,899.01	$683.15	$768.12	$84.97	12.4%
70.0%	2,385.06	$801.02	$907.13	$106.11	13.2%
80.0%	3,120.90	$979.46	$1,117.58	$138.12	14.1%
90.0%	4,464.86	$1,305.37	$1,501.95	$196.58	15.1%
100.0%	8,063.23	$2,177.97	$2,531.08	$353.11	16.2%
Average	2,527.37	$835.53	$947.83	$112.30	13.4%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$222.64	(1)	Customer Charge ($/customer)	$225.00	(3)
Distribution Charge - All therms ($/thm)	$0.2425	(1)	Distribution Charge - All therms ($/thm)	$0.2860	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.7437	(2)	COGC ($/thm)	$0.7393	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Medium Annual, High Winter Use - G41
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$222.64	$225.00	$2.36	1.1%
20.0%	8.12	$227.86	$230.97	$3.12	1.4%
30.0%	50.08	$254.82	$261.83	$7.02	2.8%
40.0%	125.85	$303.50	$317.57	$14.06	4.6%
50.0%	243.55	$379.13	$404.14	$25.01	6.6%
60.0%	375.58	$463.96	$501.25	$37.29	8.0%
70.0%	522.98	$558.66	$609.66	$51.00	9.1%
80.0%	723.73	$687.65	$757.32	$69.67	10.1%
90.0%	1,101.48	$930.36	$1,035.16	$104.80	11.3%
100.0%	2,699.06	$1,956.83	$2,210.21	$253.38	12.9%
Average	585.04	$598.54	$655.31	$56.77	9.5%
		Distribution Only			
10.0%	0.00	$222.64	$225.00	$2.36	1.1%
20.0%	8.12	$224.18	$227.32	$3.14	1.4%
30.0%	50.08	$232.13	$239.32	$7.19	3.1%
40.0%	125.85	$246.49	$260.99	$14.50	5.9%
50.0%	243.55	$268.79	$294.66	$25.86	9.6%
60.0%	375.58	$293.81	$332.42	$38.60	13.1%
70.0%	522.98	$321.74	$374.57	$52.83	16.4%
80.0%	723.73	$359.79	$431.99	$72.20	20.1%
90.0%	1,101.48	$431.37	$540.02	$108.65	25.2%
100.0%	2,699.06	$734.11	$996.93	$262.82	35.8%
Average	585.04	$333.51	$392.32	$58.82	17.6%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$222.64	(1)	Customer Charge ($/customer)	$225.00	(3)
Distribution Charge - All therms ($/thm)	$0.1895	(1)	Distribution Charge - All therms ($/thm)	$0.2860	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.4058	(2)	COGC ($/thm)	$0.4061	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Medium Annual, Low Winter Use - G51
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	298.97	$481.21	$481.31	$0.10	0.0%
20.0%	665.04	$797.83	$795.16	($2.68)	-0.3%
30.0%	830.71	$941.12	$937.19	($3.93)	-0.4%
40.0%	961.40	$1,054.16	$1,049.24	($4.92)	-0.5%
50.1%	1,110.81	$1,183.38	$1,177.33	($6.05)	-0.5%
60.1%	1,275.37	$1,325.71	$1,318.41	($7.30)	-0.6%
70.0%	1,540.79	$1,547.73	$1,545.96	($1.77)	-0.1%
80.0%	1,950.17	$1,888.99	$1,896.93	$7.94	0.4%
90.0%	2,919.75	$2,697.23	$2,728.18	$30.95	1.1%
100.0%	5,195.70	$4,594.46	$4,679.41	$84.95	1.8%
Average	1,674.87	$1,659.50	$1,660.91	$1.41	0.1%
		Distribution Only			
10.0%	298.97	$273.82	$276.36	$2.54	0.9%
20.0%	665.04	$336.50	$339.25	$2.76	0.8%
30.0%	830.71	$364.86	$367.72	$2.86	0.8%
40.0%	961.40	$387.23	$390.17	$2.94	0.8%
50.1%	1,110.81	$412.81	$415.84	$3.03	0.7%
60.1%	1,275.37	$440.98	$444.11	$3.13	0.7%
70.0%	1,540.79	$478.89	$489.71	$10.82	2.3%
80.0%	1,950.17	$536.16	$560.04	$23.88	4.5%
90.0%	2,919.75	$671.80	$726.61	$54.81	8.2%
100.0%	5,195.70	$990.21	$1,117.62	$127.41	12.9%
Average	1,674.87	$497.64	$512.74	$15.10	3.0%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$222.64	(1)	Customer Charge ($/customer)	$225.00	(3)
Distribution Charge - First 1,300 therms ($/thm)	$0.1712	(1)	Distribution Charge - All therms ($/thm)	$0.1718	(3)
Distribution Charge - Excess 1,300 therms ($/thm)	$0.1399	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.6465	(2)	COGC ($/thm)	$0.6421	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Medium Annual, Low Winter Use - G51
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	112.57	$280.45	$286.71	$6.26	2.2%
20.0%	415.51	$436.03	$452.77	$16.74	3.8%
30.0%	530.84	$495.26	$515.99	$20.73	4.2%
40.0%	615.04	$538.51	$562.15	$23.64	4.4%
50.0%	707.58	$586.03	$612.87	$26.84	4.6%
60.0%	801.28	$634.15	$664.24	$30.09	4.7%
70.0%	921.82	$696.06	$730.31	$34.26	4.9%
80.0%	1,114.68	$792.23	$836.03	$43.80	5.5%
90.0%	1,569.17	$1,014.29	$1,085.17	$70.89	7.0%
100.0%	3,257.80	$1,839.29	$2,010.83	$171.54	9.3%
Average	1,004.63	$738.47	$775.71	$37.24	5.0%
		Distribution Only			
10.0%	112.57	$237.69	$244.34	$6.65	2.8%
20.0%	415.51	$278.19	$296.38	$18.19	6.5%
30.0%	530.84	$293.61	$316.20	$22.58	7.7%
40.0%	615.04	$304.87	$330.66	$25.79	8.5%
50.0%	707.58	$317.24	$346.56	$29.32	9.2%
60.0%	801.28	$329.77	$362.66	$32.89	10.0%
70.0%	921.82	$345.89	$383.37	$37.48	10.8%
80.0%	1,114.68	$368.81	$416.50	$47.70	12.9%
90.0%	1,569.17	$418.21	$494.58	$76.37	18.3%
100.0%	3,257.80	$601.76	$784.69	$182.93	30.4%
Average	1,004.63	$356.84	$397.60	$40.75	11.4%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$222.64	(1)	Customer Charge ($/customer)	$225.00	(3)
Distribution Charge - First 1,000 therms ($/thm)	$0.1337	(1)	Distribution Charge - All therms ($/thm)	$0.1718	(3)
Distribution Charge - Excess 1,000 therms ($/thm)	$0.1087	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.3327	(2)	COGC ($/thm)	$0.3330	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - High Annual, High Winter Use - G42
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.2%	3,952.46	$5,245.98	$5,300.20	$54.22	1.0%
20.0%	7,213.13	$8,471.76	$8,559.00	$87.24	1.0%
30.2%	9,121.50	$10,359.71	$10,466.28	$106.56	1.0%
40.0%	10,470.29	$11,694.07	$11,814.29	$120.22	1.0%
50.2%	11,571.15	$12,783.15	$12,914.52	$131.37	1.0%
60.0%	13,509.92	$14,701.17	$14,852.17	$151.00	1.0%
70.2%	15,600.24	$16,769.12	$16,941.30	$172.17	1.0%
80.0%	18,555.29	$19,692.56	$19,894.66	$202.10	1.0%
90.2%	24,287.75	$25,363.68	$25,623.83	$260.15	1.0%
100.0%	94,489.70	$94,814.48	$95,785.55	$971.08	1.0%
Average	20,877.14	$21,989.57	$22,215.18	$225.61	1.0%
		Distribution Only			
10.2%	3,952.46	$2,119.98	$2,206.50	$86.52	4.1%
20.0%	7,213.13	$2,766.90	$2,913.09	$146.19	5.3%
30.2%	9,121.50	$3,145.52	$3,326.63	$181.11	5.8%
40.0%	10,470.29	$3,413.12	$3,618.91	$205.80	6.0%
50.2%	11,571.15	$3,631.53	$3,857.47	$225.94	6.2%
60.0%	13,509.92	$4,016.18	$4,277.60	$261.42	6.5%
70.2%	15,600.24	$4,430.90	$4,730.57	$299.67	6.8%
80.0%	18,555.29	$5,017.18	$5,370.93	$353.75	7.1%
90.2%	24,287.75	$6,154.50	$6,613.16	$458.66	7.5%
100.0%	94,489.70	$20,082.57	$21,825.92	$1,743.35	8.7%
Average	20,877.14	$5,477.84	$5,874.08	$396.24	7.2%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$1,335.81	(1)	Customer Charge ($/customer)	$1,350.00	(3)
Distribution Charge - All therms ($/thm)	$0.1984	(1)	Distribution Charge - All therms ($/thm)	$0.2167	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.7437	(2)	COGC ($/thm)	$0.7393	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - High Annual, High Winter Use - G42
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.1%	145.06	$1,419.02	$1,446.64	$27.62	1.9%
20.2%	557.94	$1,655.85	$1,721.71	$65.86	4.0%
29.8%	1,236.71	$2,045.21	$2,173.92	$128.71	6.3%
39.9%	2,019.46	$2,494.20	$2,695.40	$201.20	8.1%
50.0%	2,763.59	$2,921.05	$3,191.16	$270.11	9.2%
60.1%	3,577.05	$3,387.66	$3,733.10	$345.44	10.2%
70.2%	4,914.67	$4,154.94	$4,624.25	$469.31	11.3%
79.8%	6,697.70	$5,177.72	$5,812.14	$634.42	12.3%
89.9%	9,872.70	$6,998.96	$7,927.40	$928.44	13.3%
100.0%	44,000.48	$26,575.22	$30,664.02	$4,088.80	15.4%
Average	7,578.54	$5,682.98	$6,398.98	$715.99	12.6%
		Distribution Only			
10.1%	145.06	$1,353.30	$1,381.44	$28.13	2.1%
20.2%	557.94	$1,403.10	$1,470.91	$67.81	4.8%
29.8%	1,236.71	$1,484.96	$1,618.00	$133.04	9.0%
39.9%	2,019.46	$1,579.36	$1,787.62	$208.26	13.2%
50.0%	2,763.59	$1,669.10	$1,948.87	$279.77	16.8%
60.1%	3,577.05	$1,767.20	$2,125.15	$357.94	20.3%
70.2%	4,914.67	$1,928.52	$2,415.01	$486.49	25.2%
79.8%	6,697.70	$2,143.55	$2,801.39	$657.84	30.7%
89.9%	9,872.70	$2,526.46	$3,489.41	$962.96	38.1%
100.0%	44,000.48	$6,642.27	$10,884.91	$4,242.64	63.9%
Average	7,578.54	$2,249.78	$2,992.27	$742.49	33.0%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$1,335.81	(1)	Customer Charge ($/customer)	$1,350.00	(3)
Distribution Charge - All therms ($/thm)	$0.1206	(1)	Distribution Charge - All therms ($/thm)	$0.2167	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.4058	(2)	COGC ($/thm)	$0.4061	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - High Annual, Low Winter Use - G52
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.3%	821.21	$2,046.73	$2,054.21	$7.48	0.4%
20.0%	8,495.02	$8,689.95	$8,634.71	($55.24)	-0.6%
30.3%	11,712.45	$11,475.28	$11,393.74	($81.54)	-0.7%
40.0%	16,972.72	$16,029.10	$15,904.57	($124.53)	-0.8%
50.3%	23,903.02	$22,028.65	$21,847.48	($181.17)	-0.8%
60.0%	34,186.20	$30,930.80	$30,665.58	($265.22)	-0.9%
70.3%	47,229.91	$42,222.75	$41,850.92	($371.82)	-0.9%
80.0%	56,936.34	$50,625.60	$50,174.44	($451.16)	-0.9%
90.3%	74,244.21	$65,609.02	$65,016.41	($592.61)	-0.9%
100.0%	158,615.50	$138,649.25	$137,367.06	($1,282.19)	-0.9%
Average	43,311.66	$38,830.71	$38,490.91	($339.80)	-0.9%
		Distribution Only			
10.3%	821.21	$1,477.06	$1,491.25	$14.19	1.0%
20.0%	8,495.02	$2,796.95	$2,811.14	$14.19	0.5%
30.3%	11,712.45	$3,350.35	$3,364.54	$14.19	0.4%
40.0%	16,972.72	$4,255.12	$4,269.31	$14.19	0.3%
50.3%	23,903.02	$5,447.13	$5,461.32	$14.19	0.3%
60.0%	34,186.20	$7,215.84	$7,230.03	$14.19	0.2%
70.3%	47,229.91	$9,459.36	$9,473.55	$14.19	0.2%
80.0%	56,936.34	$11,128.86	$11,143.05	$14.19	0.1%
90.3%	74,244.21	$14,105.81	$14,120.00	$14.19	0.1%
100.0%	158,615.50	$28,617.68	$28,631.87	$14.19	0.0%
Average	43,311.66	$8,785.42	$8,799.61	$14.19	0.2%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$1,335.81	(1)	Customer Charge ($/customer)	$1,350.00	(3)
Distribution Charge - All therms ($/thm)	$0.1720	(1)	Distribution Charge - All therms ($/thm)	$0.1720	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.6465	(2)	COGC ($/thm)	$0.6421	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - High Annual, Low Winter Use - G52
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.1%	2,623.08	$2,539.98	$2,631.30	$91.32	3.6%
20.1%	8,643.71	$5,303.85	$5,572.20	$268.35	5.1%
30.2%	11,831.46	$6,767.24	$7,129.32	$362.08	5.4%
40.2%	18,488.22	$9,823.14	$10,380.95	$557.81	5.7%
50.3%	25,068.63	$12,843.98	$13,595.29	$751.30	5.8%
59.8%	29,171.12	$14,727.30	$15,599.23	$871.93	5.9%
69.8%	35,448.25	$17,608.92	$18,665.42	$1,056.50	6.0%
79.9%	47,888.13	$23,319.65	$24,741.93	$1,422.28	6.1%
89.9%	70,667.62	$33,776.96	$35,869.04	$2,092.08	6.2%
100.0%	143,682.62	$67,295.71	$71,534.71	$4,239.00	6.3%
Average	39,351.28	$19,400.67	$20,571.94	$1,171.26	6.0%
		Distribution Only			
10.1%	2,623.08	$1,543.56	$1,644.05	$100.49	6.5%
20.1%	8,643.71	$2,020.39	$2,318.96	$298.57	14.8%
30.2%	11,831.46	$2,272.86	$2,676.31	$403.45	17.8%
40.2%	18,488.22	$2,800.08	$3,422.53	$622.45	22.2%
50.3%	25,068.63	$3,321.25	$4,160.19	$838.95	25.3%
59.8%	29,171.12	$3,646.16	$4,620.08	$973.92	26.7%
69.8%	35,448.25	$4,143.31	$5,323.75	$1,180.44	28.5%
79.9%	47,888.13	$5,128.55	$6,718.26	$1,589.71	31.0%
89.9%	70,667.62	$6,932.69	$9,271.84	$2,339.15	33.7%
100.0%	143,682.62	$12,715.47	$17,456.82	$4,741.35	37.3%
Average	39,351.28	$4,452.43	$5,761.28	$1,308.85	29.4%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$1,335.81	(1)	Customer Charge ($/customer)	$1,350.00	(3)
Distribution Charge - All therms ($/thm)	$0.0792	(1)	Distribution Charge - All therms ($/thm)	$0.1121	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.3327	(2)	COGC ($/thm)	$0.3330	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - New Hampshire Division
Typical Residential Heating Bill (R-5)
Bill Impacts Illustrating Changes on a Monthly Basis
Current Rates and Proposed Rates, using 6 month average COGC

Line No.	Residential Heating (R-5)	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total Peak	Total Off-Peak	Annual Nov-Oct
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	Test Year Monthly Weather Normalized Therms per Custome	52	$101	133	139	115	78	44	26	11	9	14	26	618	131	749
2																
3	**Current November - October Rates**															
4	Customer Charge	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20			
5	Distribution	$0.6920	$0.6920	$0.6920	$0.6920	$0.6920	$0.6920	$0.6099	$0.6099	$0.6099	$0.6099	$0.6099	$0.6099			
6	LDAC ($/therm)	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099			
7	COGC ($/therm)	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724			
8																
9	TOTAL BILL	$101.87	$176.60	$226.34	$235.99	$199.08	$141.54	$70.66	$50.14	$34.54	$32.46	$37.14	$51.08	$1,081	$276	$1,357
10																
11																
12	**Proposed November - October Rates**															
13	Customer Charge	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84			
14	Distribution	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491			
15	LDAC ($/therm)	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965			
16	COGC ($/therm) inc. increment	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727			
17																
18	TOTAL BILL	$114.75	$196.27	$250.53	$261.05	$220.79	$158.03	$86.33	$61.56	$42.73	$40.23	$45.87	$62.70	$1,201	$339	$1,541
19																
20	**Proposed Bill less Current Bill**															
21	Total Bill increase/(decrease)	$12.88	$19.67	$24.19	$25.06	$21.71	$16.48	$15.67	$11.42	$8.19	$7.76	$8.73	$11.62	$120	$63	$183
22	Percentage increase/(decrease)	12.6%	11.1%	10.7%	10.6%	10.9%	11.6%	22.2%	22.8%	23.7%	23.9%	23.5%	22.7%	11.1%	23.0%	13.5%

Northern Utilities - New Hampshire Division
Typical Low Income Residential Heating Bill (R-10)
Bill Impacts Illustrating Changes on a Monthly Basis
Current Rates and Proposed Rates, using 6 month average COGC

Line No.	Low Income Residential Heating (R-10)	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total Peak	Total Off-Peak	Annual Nov-Oct
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	Test Year Monthly Weather Normalized Therms per Custome	50	86	121	130	116	82	47	26	10	8	13	27	585	132	717
2																
3	**Current November - October Rates**															
4	Customer Charge	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20			
5	Distribution	$0.6920	$0.6920	$0.6920	$0.6920	$0.6920	$0.6920	$0.6099	$0.6099	$0.6099	$0.6099	$0.6099	$0.6099			
6	LDAC ($/therm)	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099			
7	COGC ($/therm)	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724			
8																
9	45% Customer Charge Discount ($/customer)	-$9.99	-$9.99	-$9.99	-$9.99	-$9.99	-$9.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00			
10	45% Therm Discount - ($/thm)	-$0.3114	-$0.3114	-$0.3114	-$0.3114	-$0.3114	-$0.3114	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000			
11	45% Therm Discount - Cost of Gas ($/thm)	-$0.3292	-$0.3292	-$0.3292	-$0.3292	-$0.3292	-$0.3292	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000			
12																
13	TOTAL BILL	$56.60	$89.19	$120.40	$128.43	$115.36	$85.62	$73.35	$50.61	$33.49	$31.34	$36.27	$51.92	$596	$277	$873
14																
15																
16	**Proposed November - October Rates**															
17	Customer Charge	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84			
18	Distribution	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491			
19	LDAC ($/therm)	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965			
20	COGC ($/therm)	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727			
21																
22	45% Customer Charge Discount ($/customer)	-$12.53	-$12.53	-$12.53	-$12.53	-$12.53	-$12.53	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00			
23	45% Therm Discount - ($/thm)	-$0.3821	-$0.3821	-$0.3821	-$0.3821	-$0.3821	-$0.3821	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000			
24	45% Therm Discount - Cost of Gas ($/thm)	-$0.3272	-$0.3272	-$0.3272	-$0.3272	-$0.3272	-$0.3272	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000			
25																
26	TOTAL BILL	$63.21	$98.38	$132.06	$140.72	$126.62	$94.53	$89.58	$62.13	$41.46	$38.87	$44.82	$63.71	$656	$341	$996
27																
28	**Proposed Bill less Current Bill**															
29	Total Bill increase/(decrease)	$6.61	$9.19	$11.66	$12.29	$11.26	$8.91	$16.23	$11.52	$7.98	$7.53	$8.55	$11.79	$60	$64	$124
30	Percentage increase/(decrease)	11.7%	10.3%	9.7%	9.6%	9.8%	10.4%	22.1%	22.8%	23.8%	24.0%	23.6%	22.7%	10.1%	23.0%	14.2%

Northern Utilities - New Hampshire Division
Typical Residential Non-Heating Bill (R-6)
Bill Impacts Illustrating Changes on a Monthly Basis
Current Rates and Proposed Rates, using 6 month average COGC

Line No.	Residential Non-Heating (R-6)	Nov (1)	Dec (2)	Jan (3)	Feb (4)	Mar (5)	Apr (6)	May (7)	Jun (8)	Jul (9)	Aug (10)	Sep (11)	Oct (12)	Total Peak (13)	Total Off-Peak (14)	Annual Nov-Oct (15)
1	Test Year Monthly Weather Normalized Therms per Custome	14	21	25	26	21	16	14	11	9	8	10	11	123	63	186
2																
3	**Current November - October Rates**															
4	Customer Charge	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20			
5	Distribution	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470			
6	LDAC ($/therm)	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099			
7	COGC ($/therm)	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724			
8																
9	TOTAL BILL	$42.60	$53.42	$59.73	$60.30	$53.62	$46.58	$37.65	$35.07	$32.45	$31.65	$33.16	$34.20	$316	$204	$520
10																
11																
12	**Proposed November - October Rates**															
13	Customer Charge	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84			
14	Distribution	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208			
15	LDAC ($/therm)	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965			
16	COGC ($/therm)	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727			
17																
18	TOTAL BILL	$54.50	$68.63	$76.87	$77.62	$68.89	$59.69	$49.59	$45.96	$42.27	$41.14	$43.27	$44.74	$406	$267	$673
19																
20	**Proposed Bill less Current Bill**															
21	Total Bill increase/(decrease)	$11.89	$15.21	$17.14	$17.31	$15.27	$13.11	$11.94	$10.89	$9.82	$9.49	$10.11	$10.54	$90	$63	$153
22	Percentage increase/(decrease)	27.9%	28.5%	28.7%	28.7%	28.5%	28.1%	31.7%	31.1%	30.3%	30.0%	30.5%	30.8%	28.4%	30.8%	29.3%

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