MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-20-___

Direct Testimony

of

Ronald J. Amen

August 26, 2020

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 17806 NE 109th Court, Redmond, Washington 98052.

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

A. I am appearing on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company").

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

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. In serving as an expert witness for Montana-Dakota in this general rate case proceeding, I am working with Black & Veatch Management Consulting, LLC ("Black & Veatch") under a subcontracting arrangement.

Q. What has been the nature of your work in the energy utility consulting field?

A. I have over 40 years of experience in the utility industry, the last 23 years of which have been in the field of utility management and economic consulting. I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing; competitive market analysis; regulatory planning and policy development; resource planning and acquisition; strategic business planning; merger and acquisition analysis; organizational restructuring; new product and service development; and load research studies. I have prepared and presented expert testimony before utility regulatory bodies across North America and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included as **Attachment A** to my testimony.

Q. Please summarize your testimony.

A. In my testimony I present Montana-Dakota's Cost of Service Study ("COSS") and discuss its results. I also present the various rate design proposals filed by Montana-Dakota in this proceeding.

My testimony consists of this introduction and summary section and the following additional sections:

- Theoretical Principles of Cost Allocation
- Montana-Dakota's COSS
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- Montana-Dakota's Rate Design Proposals
- Customer Bill Impacts

Q. Please provide a list of the exhibits and schedules supporting your testimony.

A. I am sponsoring Statement K, Statement L, and the following exhibits:

- Exhibit No.____(RJA-1), Proposed Revenue Allocation
- Exhibit No.____(RJA-2), Rate 60 Residential Bill Comparison
- Exhibit No.____(RJA-3), Wahpeton Transition Phase 1 & 2 Rate Design
- Exhibit No.____(RJA-4), Rate 70 Firm General Service Bill Comparisons, and
- Exhibit No.____(RJA-5), Wahpeton Rate 63 Residential Bill Comparisons.

II. THEORETICAL PRINCIPLES OF COST ALLOCTION

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 COSS is a useful tool for determining the allocation of Montana-Dakota '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, as discussed below, 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 make a contribution 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.

SAC is an important concept for Montana-Dakota because certain customers have competitive options for the end uses supplied by natural gas through the use of alternative fuels. As a result, subsidy-free prices permit all customers to benefit from the system's scale and common costs, and all customers are better off because the system is sustainable. If strict application of the cost allocation study suggests rates that exceed SAC for some customers, prices must nevertheless be set below the SAC, but above marginal cost, to ensure that those customers make the maximum practical contribution to the common costs of the utility.

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 Local Distribution Company's ("LDC'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 COSS 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.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by customer 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 manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service. For some classes such as the largest customers, the meter cost may be unique for each customer.

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.

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 a COSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups 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 particular 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 customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. Were direct assignments of plant made in Montana-Dakota's COSS?

A. Yes. Special studies were performed to determine a portion of the specific distribution plant installed to serve Montana-Dakota's Large Firm General, Small Interruptible, Large Interruptible, and Minot Air Force Base (Minot AFB) customers. The costs related to these facilities from the following plant accounts were directly assigned to the Small Firm General, Small Interruptible, Large Interruptible, and Minot AFB customer classes.

- Account 375 – Structures and Improvements. Direct assignment to Large Firm General (Rate 70), Large Interruptible (Rate 82), and Minot AFB Delivery (Rate 64).

- Account 376 – Mains. Direct assignment to Large Interruptible (Rate 82) and Minot AFB Distribution (Rate 65).
- Account 378 – Measuring & Regulating Equipment – General. Direct assignment to Large Firm General (Rate 70), Small Interruptible Rates (71 & 81), and Large Interruptible (Rate 82).
- Account 379 – Measuring & Regulating Equipment - City Gate. Direct assignment to Minot AFB Delivery (Rate 64).
- Account 380 – Services, Customer Component. Direct assignment to Minot AFB Distribution (Rate 65).
- Account 381 – Meters, Customer Component. Direct assignment to Minot AFB Distribution (Rate 65).
- Account 383 – Service Regulators, Customer Component. Direct assignment to Minot AFB Distribution (Rate 65).
- Account 385 – Industrial Measuring & Regulating Station Equipment. Direct assignment to Small Interruptible and Large Interruptible (Rates 71 and 82) and Minot AFB Delivery (Rate 64).
- Account 387.1 – Cathodic Protection Equipment. Direct assignment to Minot AFB Distribution (Rate 65).

III. MONTANA-DAKOTA'S COST OF SERVICE STUDY

A. Process Steps and Structure of the Cost of Service Study

Q. Please describe the process of performing Montana-Dakota's COSS analysis.

A. Three broad steps were followed to perform the Company's COSS: (1) functionalization, (2) classification, and (3) allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service include production (i.e., gas supply expenses), distribution and general. 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.

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

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 Montana-Dakota's COSS?

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 of North Dakota 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 transmission and distribution system are important. The specific characteristics of the system configuration, such as, whether the distribution system is a centralized or a dispersed one, should be identified. 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. What are the specific physical characteristics of Montana-Dakota's system?

A. The physical configuration of Montana-Dakota's system is a dispersed / multiple city-gate, primarily distribution-only and multi pressure-based system. The pipeline providing the gas supply to the Wahpeton area is classified as a transmission pipeline.

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

A. All cost of service data has been extracted from the Company's total cost of service (i.e., total revenue requirement) and subsidiary schedules contained in this filing.

Q. How does the availability of data influence a COSS?

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. Montana-Dakota maintains detailed plant accounting records for many of its distribution-related facilities.

Q. How are Montana-Dakota's classes structured for purposes of the COSS?

A. The COSS evaluated seven customer classes: Residential, Small Firm General, Large Firm General, Air Force Delivery (Rate 64), Small Interruptible Sales and Transportation, Large Interruptible Sales and Transportation, and the Minot Air Force Base Distribution (Rate 65).

Q. Please explain the customer class labeled as Minot AFB Distribution?

A. The Minot AFB Distribution customer class represents the cost of service associated with the Minot AFB distribution system Montana-Dakota purchased in 2008. The costs associated with Montana-Dakota's ownership of this system are recovered under a contract with the Minot AFB and set forth on the Air Force Distribution System Rate Schedule 65 authorized by the North Dakota Public Service Commission in Case No. PU-06-470. Montana-Dakota has included an updated cost of service analysis in this case to demonstrate that other customers are not subsidizing distribution service to Minot AFB.

Q. How do state regulatory policies bear upon a utility's COSS?

A. State regulatory policies and requirements prescribe whether there is a particular approach historically used to establish utility rates in the state. Specifically, state regulations may set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the cost allocation method utilized by the utility.

B. Classification and Allocation of Distribution Mains

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

A. The Company classified 30% of its investment in distribution mains as customer related and 70% 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 Montana-Dakota'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 Company's choice of classification and allocation methods?

A. It is widely accepted that distribution mains (FERC Account No. 376) are installed to meet both system peak period load requirements and to connect customers to the LDC'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 an LDC 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 LDC's gas 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 LDC.

Q. Is the method used by the Company 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, 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 LDC'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 LDC's distribution system, regardless of the customer's peak or annual gas consumption.

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 Montana-Dakota's COSS, both the zero-intercept method and the minimum system method were employed to test the reasonableness, by comparison, of the two approaches.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, <u>Electric Utility Cost Allocation Manual</u>, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC"), and <u>Gas Rate Fundamentals</u>, 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 Montana-Dakota'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. The zero-intercept method typically uses linear regression analysis to compare unit costs of the various sized distribution mains installed on Montana-Dakota's gas system against the size (diameter) of the various distribution mains installed. This method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of its peak or annual consumption. The linear regression analysis can be expressed formulaically as follows:

$y = mx^2 + b$

Where: y = average cost per installed foot of Montana-Dakota's distribution mains

m = cost per installed foot, per inch of pipe diameter

x^2 = diameter squared of distribution mains

b = minimum cost per installed foot (the zero-intercept)

This equation determines that regardless of the main's diameter, the average cost of a distribution main on Montana-Dakota's gas system will be at least equal to a minimum cost per installed foot. This per foot cost component is exclusively related to the simple fact that Montana-Dakota incurs this cost to install a main, regardless of its size. 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. This is the per foot customer cost component of Montana-Dakota's distribution mains as distinguished from the per foot demand cost component, which is equal to a cost per foot times the diameter of the distribution main.

Q. Do the results of the zero-intercept method described above therefore support the 30% classification of distribution mains as customer related, used by the Company?

A. Yes. Applying the weighted average of the regression results for plastic and steel mains of $5.01 per foot cost of the "zero inch" distribution main to the Company's total footage of distribution mains results in an investment amount equivalent to approximately 25.9% of the total investment in distribution mains, on a current cost (year 2019) basis.

Q. How do the results under the zero-intercept method compare to the results under the most commonly installed, minimum-sized mains investment approach for Montana-Dakota's North Dakota service territory?

A. For the purpose of comparison, the most commonly installed, minimum-sized distribution mains analysis focused on 2-inch plastic pipe. In the last twenty-five years,1994 through 2019, 3.7 million feet out of approximately 6.7 million total feet or 55% of distribution mains installed in Montana-Dakota's North Dakota service territory was 2-inch plastic pipe. The dominant pipe size for new distribution main installations by far is 2-inch plastic. Since 1994, the second most footage of installed distribution mains was 4-inch plastic pipe, approximately 1.36 million feet. The 2-inch plastic pipe analysis, adjusted downward to account for its load carrying capacity, yielded a minimum system result of 35.4%. When compared to the zero-intercept analysis results, the mid-point of the 10-percentage point band-width or 30% was selected for the customer component of distribution mains.

Q. Montana-Dakota's distribution mains plant data for North Dakota indicates the installation of smaller sized pipe (1 ¼-inch or less) over the 25-year period. Why wasn't a smaller pipe size chosen for the minimum system analysis?

A. Information provided by Montana-Dakota's engineering and construction personnel indicated that use of the smaller sized pipe (i.e., less than 2-inch) for distribution mains is limited to special situations, such as a street crossing from a larger size main to provide service to two or three premises. These smaller size main segments are installed when a subdivision's underground utility infrastructure – water, sewer, power – road beds, and curbing are installed. These smaller diameter pipes are treated for plant accounting purposes as distribution mains since no service lines will be installed until a house structure is under construction and final grading of the property is complete.

Q. Would one expect there to be a strong correlation between the number of customers served by Montana-Dakota 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 Montana-Dakota'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 Montana-

Dakota 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.

C. Distribution and General Plant Classification and Allocation

Q. How were the remaining Distribution Plant costs treated in the COSS?

A. As discussed earlier, where possible, costs were directly assigned to the customer classes based on data in the Company's plant records. Weighting factors were developed for plant costs in FERC Account Nos. 380 (Services) and 381 (Meters) based on the size and type of the facilities and equipment. The classification and allocation of the remaining account balances of the directly assigned costs discussed earlier were based on the meters and distribution mains allocators, respectively. The costs in Accounts Nos. 374 (Land & Right of Way); 378 & 379 (Measurement & Regulator Station Equipment – General & City Gate); 387 (Cathodic Protection Equipment); and 375 (Structures & Improvements) were classified and allocated based on the distribution mains allocator.

Q. How were the General and Common Plant costs classified and allocated in the COSS?

A. With one exception, General and Common Plant costs were classified and allocated to the customer classes based on an internal allocation factor generated from the results of the classification and allocation of distribution plant costs. Common Intangible – Customer Care & Billing (CC&B) plant was classified as customer-related and allocated on the average number of customers.

D. Operation & Maintenance, Customer Accounts & Services, and Administrative & General Expenses

Q. How were O&M expenses classified and allocated in the COSS?

A. Generally, the classification and allocation of the Operation & Maintenance (O&M) expenses followed the treatment of the related plant accounts with the exception of Account No. 879 (Customer Installations Expense), the treatment of which followed the weighted meters allocator.

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), 903 (Customer Records & Collections) and 904 (Uncollectible Accounts). Meter reading expenses were allocated based on the total annualized number of customers weighted by meter size. A composite allocation factor was created for customer records and collections expenses, based on a study of the various functions and related activities of the responsibility areas that charged to this account. Uncollectible accounts expenses were assigned to the residential and small firm general classes based on number of customers, which reflected the historical uncollectible expense experience.

Q. Please explain the treatment of Administrative and General expenses in the COSS?

A. The majority of the A&G expenses were classified and allocated based on the internally generated allocation factor of total O&M expenses, excluding gas supply related costs and A&G. Taxes Other than Income Taxes and their corresponding [allocation basis] includes: Ad Valorem taxes [Distribution plant]; Payroll, Franchise and Other taxes [O&M excluding gas costs]; and Revenue taxes [Pro forma operating revenue].

E. Cost of Service Study Results

Q. Please explain the COSS information contained in Statement K.

A. Statement K, Schedule K-1, pages 1 – 4, provides a report entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the Pro Forma rate of return of 7.304 percent were to be earned for the demand, energy and customer cost components of each rate schedule along with a summary of the results by the major rate classifications, Residential, Small Firm General, Large Firm General, Air Force Delivery (Rate 64), Small Interruptible Sales and Transportation, Large Interruptible Sales and Transportation, and Air Force Distribution (Rate 65) .

Statement K, Schedule K-2, pages 1 – 18, is a report of the projected 2021 rate base and income statement as allocated to each rate schedule. The description of each allocator and the allocation factors for each class and cost component are provided in Statement K, Schedule K-3.

The COSS is based on a projected 2021 average test period for North Dakota natural gas operations sponsored by Company witness Ms. Vesey.

Q. Please summarize the results of the COSS.

A. As shown in Statement K, Schedule K-1, the overall rate of return for North Dakota natural gas service is 3.631%, based on the projected results of operations for the 12 months ended December 31, 2021, adjusted for known and measurable changes. The returns by customer class are shown below:

• Residential Service	1.853%
• Small Firm General Service	4.237%
• Large Firm General Service	5.935%
• Minot AFB Delivery	0.677%
• Small Interruptible Sales & Transportation	6.870%
• Large Interruptible Sales & Transportation	19.217%
• Minot AFB Distribution	19.339%

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design you rely upon as the basis for rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature. These include:

- Efficiency;
- Cost of Service;
- Value of Service;
- Stability;
- Non-Discrimination;
- Administrative Simplicity; and
- 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. Each of these principles plays an important role in analyzing the rate design proposals of Montana-Dakota.

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 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 Montana-Dakota 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. In this case, this principle is an important requirement that supports Montana-Dakota's proposed use of a single monthly Basic Service Charge for all customers within certain of its tariff schedules.

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 I 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. For example, as noted above, there are tensions between cost and value of service principles.

Q. Please describe the conflict between marginal cost price signals and the recovery of the utility's revenue requirement.

A. The conflict between proper price signals based on marginal cost and the balanced budget principle arises because marginal cost is below average cost due to economies of scale. Where fixed delivery service costs do not vary with the volume of gas sales, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of the customer accessing the entire gas delivery system. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the utility's total revenue requirement. This suggests that efficient price signals may require a multi-part tariff designed to meet the utility's revenue requirements while sending marginal cost price signals related to gas consumption decisions. Properly designed, a multi-part tariff may include elements such as access charges, facilities charges, demand charges, consumption charges, and the potential for revenue credits.

In the case of a local distribution company ("LDC") such as Montana-Dakota, for residential and small commercial customers, the combination of scale economies and class homogeneity may permit the use of a single fixed monthly charge that meets all of the requirements for an efficient rate that recovers the utility's revenue requirement that is derived on an embedded cost basis. For larger customers, a combination of these elements permits proper price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the added complexity of a demand charge may not be a concern. Further, for the largest customers, the cost of metering is customer-specific and each customer creates its own unique requirements for gas distribution service based on factors such as distance from the utility's city gate, pressure requirements, and contract demand levels.

Q. Are there other potential conflicts?

A. Yes. 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. Please summarize Bonbright's three primary criteria for sound rate design.

A. Bonbright identifies the three primary criteria for sound rate design as follows:

- Capital Attraction
- Consumer Rationing
- Fairness to Ratepayers

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

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

A. The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

- System cost characteristics such as established in the COSS required by the Commission, or embedded customer, demand, and commodity related costs by type of service;
- Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
- Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics, and LDC bypass alternatives; and
- Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of underutilized facilities, opportunities to offer new services and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact from modifications to the rates. In each case, a rate design seeks to recover the authorized level of revenue based on the billing determinants expected to occur during the test period used to develop the rates.

The overall rate design process, which includes both the apportionment of the revenues to be recovered among customer classes and the determination of rate structures within customer 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 into 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 has to be, in part, influenced by judgmental evaluations.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Montana-Dakota's proposed revenue increase of $8,972,424 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 Montana-Dakota's customer classes.

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

A. Yes. Using Montana-Dakota's proposed revenue increase, and the results of its COSS, I evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Montana-Dakota personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option that I evaluated under Montana-Dakota'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 Exhibit No.___(RJA-1), Proposed Revenue Allocation, under *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. Revenue changes under this option and all remaining options for Minot AFB Distribution will not be proposed as its revenues are determined by contract with Montana-Dakota. All revenue changes shown for Minot AFB Distribution in Exhibit No.___ RJA-1 are for illustrative purposes only.

A second option I considered was assigning the increase in revenues to Montana-Dakota's customer classes based on an equal percentage basis of its current non-gas revenues (see *Scenario A, Equal Percentage Increase*, in Exhibit No.___ RJA-1). 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 Montana-Dakota'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 Montana-Dakota's class revenue proposal.

A third option was to exempt the customer classes that are above parity under current rates from receiving any revenue increase. This option would preserve the current parity ratio for the Large Interruptible Sales & Transportation class (see *Scenario B*, *No Class Increase Above Parity*, in Exhibit No.___ RJA-1).

Q. What was the result of this process?

A. After further discussions with Montana-Dakota, I concluded that the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all of Montana-Dakota's customer classes: Residential Service (Rate Schedules 60), Small General Service (Rate Schedule 70), Large Firm General Service (Rate Schedule 70), Minot AFB Delivery Service (Rate Schedule 64), Small Interruptible Sales & Transportation Service class (Rate Schedules 71 and 81) and Large Interruptible Sales & Transportation Service (Rate Schedule 82 and 85), as shown in Exhibit No.___ RJA-1 as *Proposed Class Revenues*. In the case of the Residential Service class, the revenue adjustment ensures their proposed rates will move class revenues closer to the COSS for the class. The proposed revenue increase to the residential class will improve the class' revenue to cost ratio from 0.74 to 0.97. The Small Firm General Service (0.85), Large General Service (0.93), Minot AFB Delivery Service (0.79), and Small Interruptible Sales & Transportation Service (0.98) classes' revenue-to-cost ratios were below unity (1.00) at the Company's proposed ROR of 7.304%. The proposed revenue increases to these respective classes will result in a revenue-to-cost ratio for each of these classes at parity. The COSS results for the remaining customer classes indicate their respective class rates of return are 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 Exhibit No.___ RJA-1 under *Revenues at Equalized Rates of Return*, the resulting customer impact implications for the Residential

Service class has led me to conclude, in consultation with the Company, to refrain from revenue reductions for the remaining customer classes, or alternatively, exempting these classes from revenue increases (*Scenario B*). Instead, the proposed respective revenue adjustments of 25% of the system average increase to eligible (non-contracted) customers, will mean these classes will be slightly higher than their current parity ratio levels relative to unity. The revenue increase for Small Interruptible Sales & Transportation Service was further adjusted to reflect the minimum adjustment of 25% of the system average increase because raising the class to parity was lower than this minimum threshold.

In summary, this preferred revenue allocation approach resulted in reasonable movement of the Residential class revenue-to-cost ratio toward unity or 1.00, while providing moderation of the revenue impact on this class by requiring some level of revenue increase responsibility from all 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.

Statement L, page 1, Revenues Under Current and Proposed Rates, presents summaries by customer rate schedule of the proposed revenue increase. This Statement displays the revenues calculated under the present and proposed rates for each customer tariff rate schedule. The proposed revenue increase by rate schedule and corresponding percentage is also shown.

The allocation of the total revenue increase of $8,972,424 to the respective rate schedules is presented in Statement L, page 3. The target revenue increase as a percentage of total class revenues, including gas costs, range from 12.51% to Residential, 6.55% to Small Firm General, 1.86% to Large Firm General, 2.26% to Minot AFB Delivery 2.51% to Small Interruptible, and 0.96% to Large Interruptible.

VI. MONTANA-DAKOTA'S RATE DESIGN PROPOSALS

Q. Please summarize Montana-Dakota's proposed rate design changes.

A. I will present the specific rate design changes and supporting rationale for Montana-Dakota's proposals. Montana-Dakota has proposed to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service for customers served under the following Rate Schedules: Residential Service (Rate Schedules 60 & 90), Small General Service (Rate Schedules 70, 72 74 & 92); Large General Service (Rate Schedule 70, 72, 74, & 92); Small Interruptible Sales & Transportation Service (Rate Schedules 71 and 81), and Large Interruptible Sales & Transportation Service (Rate Schedules 85 and 82), as shown on Statement L . Following the revenue increases recovered through the Basic Service Charges, except for the Residential Service and Small Interruptible Service rate schedules, the remaining allocated revenue increases for these customer classes will be recovered in their respective volumetric Distribution Delivery Charge components. The Residential Rate Schedules do not contain a Distribution Delivery Charge and the Small Interruptible Service Rate Schedules will receive a decrease in their Distribution Delivery Charges, as further described below.

Q. Please describe the proposed changes to the Basic Service Charges for the respective tariff schedules.

A. As seen on page 4 of Statement L the Basic Service Charge under Residential Rate 60 is proposed at $0.8919 per day which reflects an average monthly charge of $27.11, an increase of approximately $6.26 per month from the currently effective charge.

The Basic Service Charge applicable to Firm General Service customers with meters rated less than 500 cubic feet per hour is proposed at $0.75 per day, and $2.13 per day for customers requiring the larger meters capable of measuring gas flows of 500 cubic feet per hour or greater. The resulting average monthly charges will be $22.81 and $64.79 respectively representing an increase of $1.52 per month in the Basic Service Charge applicable to customers using meters rated less than 500 cubic feet per hour and an increase of $2.44 per month in the Basic Service Charge for customers requiring meters rated at 500 cubic feet per hour or higher. The rate calculations for the Firm General classes are included on pages 7-8 of Statement L.

The proposed Basic Service Charge applicable to Small Interruptible Sales (Rate Schedule 71) and Transportation (Rate Schedule 81) Service customers is $450.00 per month. While this level of basic charge is greater than the total allocated customer related costs for the Small Interruptible Service class, it improves the level of fixed costs attributable to the class recovered through a fixed monthly charge. In addition, this level of Basic Service Charge will permit the current large differential between the Interruptible Sales and Transportation Distribution Delivery Charges to be eliminated, resulting in a uniform volumetric rate and a decrease in the charge for both Sales Rate Schedule 71 and Transportation Rate Schedule 81customers. The rate calculations for the Small Interruptible Service class are included on page 9 of Statement L.

The proposed Basic Service Charge applicable to Large Interruptible Sales (Rate Schedule 85) and Transportation (Rate Schedule 82) Service customers is $1,600.00 per month, a $100.00 increase in the level of the current charge. As stated earlier, these proposed increases to the Basic Service Charges will provide significant improvement in the recovery of the fixed costs via fixed charges.

Q. Do increases in Basic Service Charges, such as those proposed by Montana-Dakota, discourage conservation of the natural gas commodity?

A. No. For example, under the Company's proposed increase to its Residential Basic Service Charge, customers will continue to have a financial incentive to pursue energy efficiency measures. The portion of the customer's gas bill represented by the Company's Basic Service Charge is less than half of the combined total bill, including the gas commodity charge incurred by the customer. As depicted in the accompanying Exhibit No.___(RJA-2), Rate 60 Residential Bill Comparison, the portion of the typical residential customer's annual bill represented by the average monthly Basic Service Charge increase of $6.26 per month is approximately 11% of the total bill. The effect of raising the proposed Basic Service Charge by $0.2059 per day, the equivalent of $6.38 per month in January, the month in which the most gas is typically consumed by residential heating customers, is only 7% of the total January bill. This is a relatively small amount. The commodity cost of gas[1] is 68% of the customer's bill in January, which continues to provide a strong economic price signal that may influence the customer's ongoing gas consumption decisions. In my opinion, the relatively small amount of fixed costs added to the Basic Service Charge that

[1] Montana-Dakota's proforma cost of gas in the COSS is $3.984 per Dk.

would otherwise be recovered in the volumetric Distribution Delivery Charge will not materially affect a customer's decision to use more or less gas.

By recovering its fixed distribution costs in the Residential Basic Service Charge, the Company will be able to continue promoting energy efficiency and conservation for its customers while moderately reducing the real threat of margin losses due to declining gas sales per customer.

Q. Does a volumetrically weighted rate design provide the most appropriate prices signals to customers related to gas consumption?

A. No. A volumetrically weighted rate design conveys improper price signals to customers because it recovers fixed costs through the volumetric components of the utility's rate structure. When this undesirable situation exists, it can: (1) increase revenue variability due to factors beyond the gas utility's ability to influence; (2) fail to account for cost differences between and within customer classes; (3) promote inefficient use of the gas utility's system; and (4) needlessly inflate bills in the winter months, when customers face the greatest pressure on their household budgets from utility bills. Montana-Dakota's rate design proposal to increase the level of its Basic Service Charges moves in the right direction to minimize these undesirable effects and best aligns the price signals to customers with the underlying costs of providing gas delivery service.

A Basic Service Charge that better reflects the level of customer related costs will result in a customer's annual bill more accurately reflecting the non-gas revenue amounts approved by the Commission in this rate case, while customers will recognize the results of their energy conservation efforts in the amount they pay for the gas commodity in their monthly bills.

In summary, a Basic Service Charge provides increased bill stability for customers and increased revenue stability for the Company.

Q. In view of the Residential Basic Service Charge proposed by the Company, can you offer any further analysis that would evaluate the magnitude of increases to which <u>individual</u> customers will be exposed?

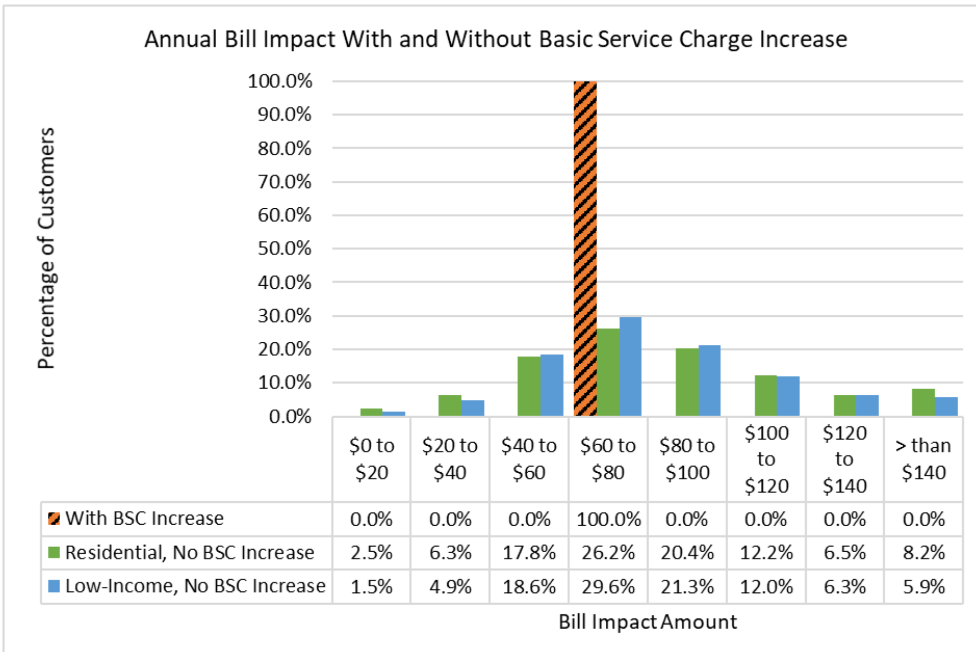
A. Yes. This can generally be assessed by analyzing how a change in rates impacts a customer's total bill, rather than the individual rate components, and is best analyzed by looking at the sum total of the customer's bills over a twelve-month period. The analysis should look at the amount of change in dollars paid instead of merely focusing on percentage increases. This is because the percentage increase in a smaller bill appears relatively high.

Q. Have you performed the analysis you recommend for the Company's Residential Basic Service Charge proposal?

A. Yes. Following as *Figure 1*, is a chart showing the impact that an increase from the current Residential Basic Service Charge to the Company's proposed $0.8919 per day Basic Service Charge, would have on bills paid by Residential customers and Residential low-income customers over a twelve-month period. This chart shows that Residential and Residential low-income customers would all see an annual increase of $60.00 to $80.00, an average monthly increase between $5.00 and $6.67 (see the bar labeled "With BSC Increase").

Figure 1 also demonstrates the comparison of the annual bill frequencies of low-income customers with those of the general population of residential customers. Although the Company does not keep records of income characteristics of its customers, it is possible to identify customers who receive bill assistance. Low-income customers generally receive LIHEAP. The Company has provided information on the annual consumption levels of LIHEAP customers. The information presented in *Figure 1* shows that the 2,683 LIHEAP customer group had annual usage profiles very similar to those of the larger Residential class. This information addresses a not uncommon perception of low-income customers, which is that they tend to be low-use customers as well.

<u>Figure 1</u>



	$0 to $20	$20 to $40	$40 to $60	$60 to $80	$80 to $100	$100 to $120	$120 to $140	> than $140
With BSC Increase	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%
Residential, No BSC Increase	2.5%	6.3%	17.8%	26.2%	20.4%	12.2%	6.5%	8.2%
Low-Income, No BSC Increase	1.5%	4.9%	18.6%	29.6%	21.3%	12.0%	6.3%	5.9%

Q. Have you evaluated the impact on low-income customers' bills if the Company's proposed revenue increase allocated to Residential customers were collected entirely in a new volumetric Distribution Delivery Service Charge?

A. Yes. *Figure 1* also provides a side-by-side comparison of the impact to Residential low-income customers from collecting the proposed Residential revenue increase in a new Distribution Delivery charge versus the proposed increase in the Basic Service Charge. The chart shows how the dispersion of the annual bill increases change when the revenue from the proposed Basic Service

Charge increase is moved to a new volumetric Distribution Delivery Charge. Under the “No BSC Increase” scenario, 45.5% or 1,219 of the low-income annual bill increases will be larger than $80.00, including 5.9% of annual bill increases exceeding $140.00, representing 157 low-income customers. This compares with 25.0% or 670 low-income annual bill increases below $60.00, including only 1.5% or 39 low-income customers that would experience an annual bill increase of $0 - $20.00.

Q. Are there other proposed rate design changes to Montana-Dakota’s non-residential rate schedules?

A. Yes. Apart from the equalization of the Small Interruptible Sales and Transportation Distribution Delivery Charges described earlier, Montana-Dakota proposes to add a Distribution Delivery Charge for the Firm General Service customers requiring meters rated at 500 cubic feet per hour or higher (Large Firm General) separate from the current Distribution Delivery Charge, which will only apply to Firm General Service customers requiring meters rated less than 500 cubic feet per hour (Small firm General). This will allow for better alignment of the Firm General Service Rate Schedule components with the corresponding class cost of service results and proposed revenue apportionment as well as guard against cross-subsidization between Small and Large Firm General Service customers. The Firm General Service Distribution Delivery Charges will continue to exclude Firm Contract Demand Service (Rate Schedule 74) customers. However, Montana-Dakota proposes to increase the Distribution Demand Charges for both Small and Large Rate Schedule 74 customers. The proposed rate components for all Firm General Service Rate Schedules are shown in Statement L, pages 7-8.

VII. <u>WAHPETON RATE SCHEDULES</u>

Q. Please describe the rate changes under the two-phase integration of Customers in the Wahpeton service area of Great Plains Natural Gas Co. into Montana-Dakota's North Dakota service territory.

A. As discussed by Company witness, Ms. Bosch, the integration of Wahpeton customers into Montana-Dakota's rate schedules will include changes in Rate Schedules and the rate structures within them. In Phase 1 of the integration, Wahpeton Residential Service (new Montana-Dakota Rate Schedule 63) and Firm General Service (new Montana-Dakota Rate Schedule 73) customers will be converted from a monthly Basic Service Charge of $3.50 to a proposed daily Basic Service Charge of $0.25, an average monthly increase of $4.10. The Distribution Delivery Service multi-block rate structure for Rate Schedules 63 and 73 will be converted to a single block rate of $1.028 per Dk.

Similar to the two new rate schedules for residential and firm general service for Wahpeton, new Montana-Dakota Wahpeton rate schedules will be established for small and large interruptible sales gas service (currently provided under Wahpeton Interruptible Service – General (Rate Schedule 71) and Transportation Service (currently provided under Interruptible Transportation Service Rate 80). Both the sales and transportation tariffs will reflect a small and large rate classification. Customers' rates will be converted from a monthly Basic Service Charge of $3.50 to a proposed monthly Basic Service Charge of $180.00. The Distribution Delivery Service multi-block rate structure for Rate Schedules 76, 86, 83 and 84 will be converted to a single block rate of $0.670 per Dk.

The proposed rate components for all Rate Schedules applicable to Wahpeton customers are located in Statement L, pages 11 to 14.

Q. Please describe the proposed rate changes under Phase 2 of integration of the Wahpeton customers into Montana-Dakota's North Dakota service territory.

A. In Phase 2 of the integration, the proposed daily Basic Service Charges applicable to Wahpeton Residential Service (new Montana-Dakota Rate Schedule 63) and Firm General Service (new Montana-Dakota Rate Schedule 73) customers will increase to $0.333 for Rate Schedule 63, $0.50 for Rate Schedule 73 customers using meters rated less than 500 cubic feet per hour (Small Firm General), and $1.00 for Rate Schedule 73 customers requiring meters rated at 500 cubic feet per hour or higher (Large Firm General). The uniform Distribution Delivery Service Charge of $1.028 per Dk under Phase 1 will change to $0.649 per Dk for Rate Schedule 63, $0.632 per Dk for Rate Schedule 73 – Small Firm General, and $0.507 per Dk Rate Schedule 73 – Large Firm General.

The Phase 2 monthly Basic Service Charge for customers served under Small Interruptible Sales Service (Rate Schedule 76) will increase from $180.00 to $250.00 and for customers served under Large Interruptible Sales Service (Rate Schedule 86), the Basic Service Charge will increase to $500.00. The uniform Distribution Delivery Service Charge of $0.670 per Dk under Phase 1 will change to $0.608 per Dk for Rate Schedule 76 and $0.656 per Dk for Rate Schedule 86 in Phase 2. Exhibit No.____(RJA-3) provides a summary of the Phase 1 and 2 rate structure and corresponding unit rates for the Wahpeton customers.

VIII. CUSTOMER BILL IMPACTS

Q. Has Montana-Dakota prepared bill comparisons for its Residential Service customers?

A. Yes. The monthly and annual bill impacts for a typical Residential customer using 88 dekatherms (Dk) per year is shown on page 1 of Exhibit No.___(RJA-2), Rate 60 Residential Bill Comparison for Residential gas service. The average monthly increase for this residential customer under the Company's proposed rate design is $6.26 or 12.50%.

Q. What are the corresponding bill comparisons for Montana-Dakota's Small Firm General and Large Firm General customers?

A. The monthly and annual bill impacts for a typical Small Firm General customer using 191 Dk per year is shown on page 1 of Exhibit No.___(RJA-4), Rate 70 Bill Comparison for Firm General gas service. The average monthly increase for this Small Firm General customer under the Company's proposed rate design is $6.38 or 6.50%. The monthly and annual bill impacts for a typical Large Firm General customer using 1,229 Dk per year is shown on page 2 of the exhibit. The average monthly increase for this Large Firm General customer under the Company's proposed rate design is $10.22 or 1.84%.

A presentation of the annual billing impacts for the Residential and Firm General Service classes is provided in Pages 16-29 of Statement L.

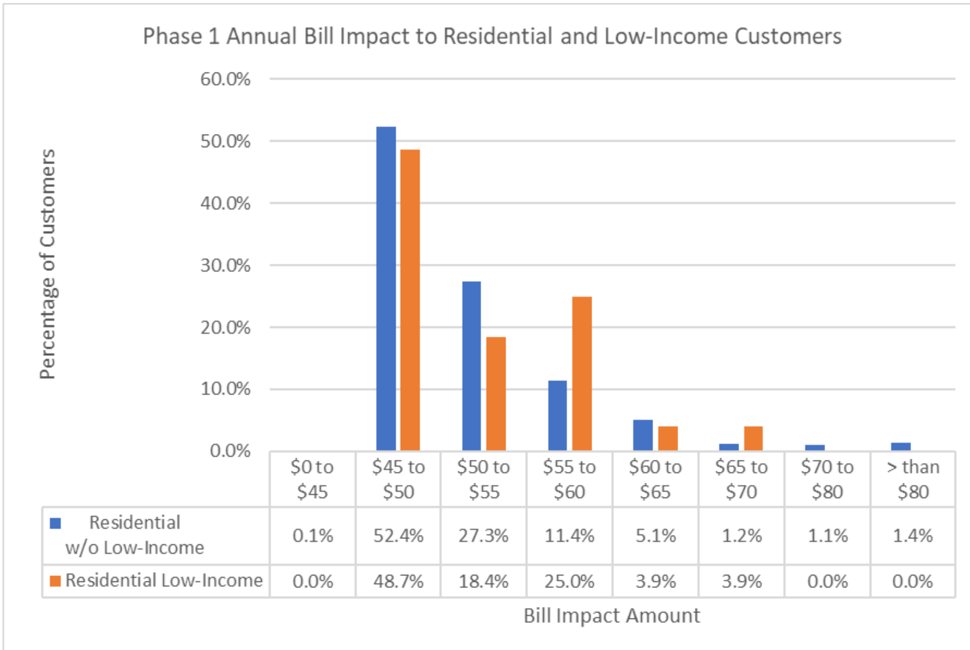
Q. Has Montana-Dakota prepared bill comparisons for its Wahpeton Residential Service customers?

A. Yes. The monthly and annual bill impacts for a typical Wahpeton Residential customer using 80 dekatherms (Dk) per year is shown on page 1 of Exhibit No.___(RJA-5), Wahpeton Rate 63 Residential Bill Comparisons. The average monthly increase for this residential customer under the Company's proposed Phase 1 rate design is $4.10 or 10.45%. Page 2 of Exhibit No.____(RJA-5) shows the largely revenue neutral impact on a typical Wahpeton Residential customer of the proposed Phase 2 rates.

Q. Have you evaluated the impact on Wahpeton low-income customers' bills for the Company's proposed revenue increase allocated to Residential customers in Phase 1 and 2 of the transition to Montana-Dakota tariff schedules?

A. Yes. *Figure 2* below provides a side-by-side comparison of the impact to Wahpeton Residential and low-income customers from collecting the proposed Residential revenue increase in Phase 1 of the proposed transition of Wahpeton customers into the Montana-Dakota rate structure. The chart shows the dispersion of the annual bill increases when the revenue increase is recovered under the new proposed daily Basic Service Charge and the current Distribution Delivery Service multi-block rate structure is converted to a single block rate. Approximately half of both Wahpeton Residential (52.4%) and low income Residential (48.7%) customers will experience an annual bill increase between $45.00 and $50.00 in Phase 1 of the transition. Another 38.7% of Wahpeton Residential customers and 43.4% of Wahpeton low-income Residential customers will see and annual increase under $60.00.

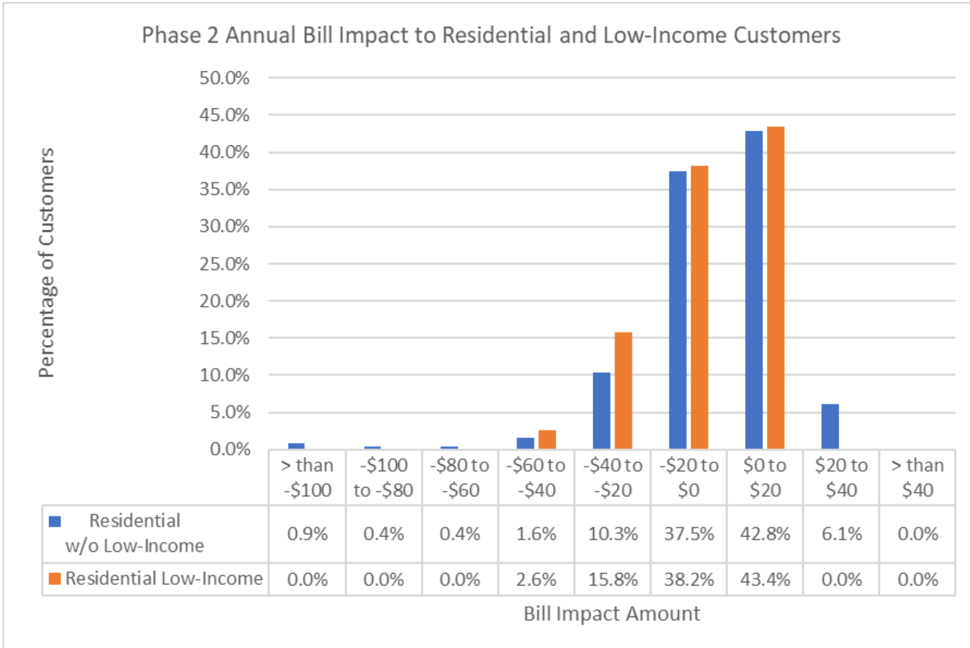
Figure 2



Q. What will be the impact on Wahpeton Residential and low-income Residential customers under Phase 2 of the transition?

A. *Figure 3* below provides a side-by-side comparison of the impact to Wahpeton Residential and low-income Residential customers from collecting the proposed Residential revenue increase in Phase 2 of the proposed transition of Wahpeton customers into the Montana-Dakota rate structure. The chart shows the revenue neutral nature of the Phase 2 rates. 80.3% of Wahpeton Residential customers and 81.6% of low-income Residential customers will experience annual bill impacts between $20.00 decreases to $20.00 increases. Another 10.3% of Wahpeton Residential customers and 15.8% low-come Residential customers will experience annual bill decreases between $20.00 and $40.00.

Figure 3



	> than -$100	-$100 to -$80	-$80 to -$60	-$60 to -$40	-$40 to -$20	-$20 to $0	$0 to $20	$20 to $40	> than $40
Residential w/o Low-Income	0.9%	0.4%	0.4%	1.6%	10.3%	37.5%	42.8%	6.1%	0.0%
Residential Low-Income	0.0%	0.0%	0.0%	2.6%	15.8%	38.2%	43.4%	0.0%	0.0%

Q. Does this conclude your direct testimony?

A. Yes.

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - MONTANA

Proposed Revenue Allocation

	Total North Dakota	Total Residential	Total Small Firm General	Total Large Firm General	Total Air Force Delivery	Total Small Interruptible	Total Large Interruptible	Total MAFB Distribution
Revenue to Cost Ratio Under Current Rates	0.82	0.74	0.85	0.93	0.79	0.98	1.68	2.09
Revenues at Equalized Rates of Return								
Revenue Increase	8,972,424	8,400,619	823,541	643,396	29,291	34,181	(720,541)	(238,063)
Total revenue at equalized rates of return	50,857,794	32,725,297	5,340,964	9,590,977	139,664	1,776,988	1,065,967	217,937
Parity Ratio	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Secnario A: Equal Percentage Increase								
Revenue Increase	8,972,424	5,210,682	967,694	1,916,695	23,643	373,333	382,695	97,681
Total revenue at equalized rates of return	50,857,794	29,535,360	5,485,117	10,864,276	134,016	2,116,140	2,169,203	553,681
Percent Increase	21.42%	21.42%	21.42%	21.42%	21.42%	21.42%	21.42%	21.42%
Parity Ratio	1.00	0.90	1.03	1.13	0.96	1.19	2.03	2.54
Secnario B: No Class Increase Above Parity								
Revenue Increase	8,972,424	7,476,196	823,541	643396	29291	0	0	0
Total revenue with no increase to classes above Parity	50,857,794	31,800,874	5,340,964	9,590,977	139,664	1,742,807	1,786,508	456,000
Percent Increase	21.42%	30.74%	18.23%	7.19%	26.54%	0.00%	0.00%	0.00%
Parity Ratio	1.00	0.97	1.00	1.00	1.00	0.98	1.68	2.09
Secnario C: Minimum Class Increase of 25% of System Average								
minimum 25% of system average increase (to elegible customers 1/)						5.57%	5.57%	
Revenue Increase	8,972,424	7,344,027	823,541	643,396	29,291	97,070	35,099	0
Total revenue at 25% system average minimum	50,857,794	31,668,705	5,340,964	9,590,977	139,664	1,839,877	1,821,607	456,000
Percent Increase	21.42%	30.19%	18.23%	7.19%	26.54%	5.57%	1.96%	0.00%
Parity Ratio	1.00	0.97	1.00	1.00	1.00	1.04	1.71	2.09

1/ "eligible customers" excludes contract rate customers

Source: Statement L

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE 60 BILL COMPARISON
RESIDENTIAL GAS SERVICE
Projected 2021

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	15	$81.03	$87.41	$6.38	7.87%
February	15	78.97	84.73	5.76	7.29%
March	12	69.07	75.46	6.39	9.25%
April	9	56.44	62.61	6.17	10.93%
May	5	41.19	47.57	6.38	15.49%
June	2	28.55	34.73	6.18	21.65%
July	1	25.25	31.63	6.38	25.27%
August	1	25.25	31.63	6.38	25.27%
September	2	28.55	34.73	6.18	21.65%
October	4	37.20	43.58	6.38	17.15%
November	9	56.44	62.61	6.17	10.93%
December	13	73.06	79.44	6.38	8.73%
Total	88	$601.00	$676.13	$75.13	12.50%

Average Increase per Month	$6.26
Annual Basic Service Charge increase percent	11%
January Basic Service Charge increase percent	7%

RATE 60	Current	Proposed	
Basic Delivery Charge	$0.6860	$0.8919	
Distribution Delivery	$0.000	$0.000	
Cost of Gas	3.984	$3.984	68%

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
WAHPETON TRANSITION PHASE 1 & 2 RATE DESIGN

PROJECTED 2021

GPNG Tariff	MDU Wahpeton Specific Tariff	Equivalent MDU Tariff	Current Rate	Proposed Phase 1 Rate	Proposed Phase 2 Rate	MDU Rate
Rate 65 - Firm Service						
Residential, Rate 65	MDU Rate 63	Rate 60				
Basic Servcie Charge			$3.50 or $0.1151 per day	$0.2500	$0.3330	$0.8919
Distribution Delivery Charge				$1.028	$0.649	$0.000
First 10 Dk			$1.072			
Over 10 Dk			$0.822			
Firm General - Small, Rate 65	MDU Rate 73, Small<500 CFH	Rate 70, Small				
Basic Servcie Charge			$3.50 or $0.1151 per day	$0.250	$0.500	$0.750
Distribution Delivery Charge				$1.028	$0.632	$1.116
First 10 Dk			$1.072			
Over 10 Dk			$0.822			
Firm General - Large Rate 65	MDU Rate 73, Large>500 CFH	Rate 70, Large				
Basic Servcie Charge			$3.50 or $0.1151 per day	$0.250	$1.000	$2.130
Distribution Delivery Charge				$1.028	$0.507	$0.887
First 10 Dk			$1.072			
Over 10 Dk			$0.822			
Rate 71 - Interruptible Sales Service						
Annual Dk < 100,000	MDU Rate 76	Rate 71 (Sales)				
Basic Servcie Charge			$3.50	$180.00	$250.00	$450.00
Distribution Delivery Charge				$0.6700	$0.6080	$0.5560
First 400 Dk			$1.0160			
Next 2,600 Dk			$0.7675			
Over 3,000 Dk			$0.6140			
Annual Dk > 100,000	MDU Rate 86	Rate 85 (Sales)				
Basic Servcie Charge			$3.50	$180.00	$500.00	$1,600.00
Distribution Delivery Charge				$0.6700	$0.6560	$0.2390
First 400 Dk			$1.0160			
Next 2,600 Dk			$0.7675			
Over 3,000 Dk			$0.6140			
Rate 80 - Interruptible Transportation Service						
Annual Dk < 100,000	MDU Rate 83	Rate 81 (Transport)				
Basic Servcie Charge			$3.50	$180.00	$250.00	$450.00
Distribution Delivery Charge				$0.6700	$0.6080	$0.5560
First 400 Dk			$1.0160			
Next 2,600 Dk			$0.7675			
Over 3,000 Dk			$0.6140			
Annual Dk > 100,000	MDU Rate 84	Rate 82 (Transport)				
Basic Servcie Charge			$3.50	$180.00	$500.00	$1,600.00
Distribution Delivery Charge				$0.6700	$0.6560	$0.2390
First 400 Dk			$1.0160			
Next 2,600 Dk			$0.7675			
Over 3,000 Dk			$0.6140			

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE 70 BILL COMPARISON
FIRM GENERAL GAS SERVICE (< 500 Cubic Feet Per Hour Meters)

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	36	$195.29	$207.82	$12.53	6.42%
February	35	188.37	200.45	12.08	6.41%
March	25	142.25	151.43	9.18	6.45%
April	18	107.80	114.79	6.99	6.48%
May	10	69.92	74.52	4.60	6.58%
June	4	40.29	43.01	2.72	6.75%
July	2	31.34	33.50	2.16	6.89%
August	2	31.34	33.50	2.16	6.89%
September	3	35.47	37.88	2.41	6.79%
October	8	60.28	64.27	3.99	6.62%
November	19	112.62	119.91	7.29	6.47%
December	29	161.54	171.93	10.39	6.43%
Total	191	$1,176.51	$1,253.01	$76.50	6.50%

Average Increase per Month $6.38

RATE 70	Current	Proposed
Basic Delivery Charge	$0.70	$0.750
Distribution Delivery	$0.811	$1.116
Cost of Gas	4.011	$4.011

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
RATE 70 BILL COMPARISON
FIRM GENERAL GAS SERVICE (> 500 Cubic Feet Per Hour Meters)

MONTH	DK	PRESENT RATE	PROPOSED RATE	AMOUNT OF INCREASE	% INCREASE
January	210	$1,076.17	$1,094.61	$18.44	1.71%
February	205	1,045.91	1,063.73	17.82	1.70%
March	153	801.32	815.42	14.10	1.76%
April	115	616.03	627.17	11.14	1.81%
May	71	405.91	413.79	7.88	1.94%
June	37	239.91	245.13	5.22	2.18%
July	28	198.57	203.17	4.60	2.32%
August	26	188.92	193.38	4.46	2.36%
September	33	220.63	225.53	4.90	2.22%
October	57	338.40	345.22	6.82	2.02%
November	121	644.96	656.56	11.60	1.80%
December	173	897.76	913.38	15.62	1.74%
Total	1229	$6,674.49	$6,797.09	$122.60	1.84%

Average Increase per Month $10.22

RATE 70	Current	Proposed
Basic Delivery Charge	$2.05	$2.13
Distribution Delivery	$0.811	$0.887
Cost of Gas	4.011	$4.011

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
WAHPETON RATE 63 BILL COMPARISON - PHASE I
RESIDENTIAL GAS SERVICE
Projected 2021

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	15	$83.44	$88.28	$4.84	5.80%
February	16	88.60	92.90	4.30	4.85%
March	12	67.95	72.18	4.23	6.23%
April	8	46.81	50.45	3.64	7.78%
May	4	25.15	29.22	4.07	16.18%
June	1	8.91	12.87	3.96	44.44%
July	1	8.91	13.12	4.21	47.25%
August	1	8.91	13.12	4.21	47.25%
September	1	8.91	12.87	3.96	44.44%
October	2	14.32	18.49	4.17	29.12%
November	8	46.81	50.45	3.64	7.78%
December	11	62.79	66.81	4.02	6.40%
Total	80	$471.51	$520.76	$49.25	10.45%
Average Increase per Month				$4.10	

RATE 63	Current	Proposed Phase 1
Basic Service Charge	$3.50	$0.250
Distribution Charge - all Dk		$1.028
Distribution Charge First 10 Dk	$1.0720	
Distribution Charge Over 10 Dk	$0.8220	
Cost of Gas	$4.3408	$4.3408

MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
WAHPETON RATE 63 BILL COMPARISON - PHASE II
RESIDENTIAL GAS SERVICE
Projected 2021

Month	Dk	Present Rate	Proposed Rate	Amount of Increase	% Increase
January	15	$88.28	$85.17	($3.11)	-3.52%
February	16	92.90	89.15	(3.75)	-4.04%
March	12	72.18	70.20	(1.98)	-2.74%
April	8	50.45	49.91	(0.54)	-1.07%
May	4	29.22	30.28	1.06	3.63%
June	1	12.87	14.98	2.11	16.39%
July	1	13.12	15.31	2.19	16.69%
August	1	13.12	15.31	2.19	16.69%
September	1	12.87	14.98	2.11	16.39%
October	2	18.49	20.30	1.81	9.79%
November	8	50.45	49.91	(0.54)	-1.07%
December	11	66.81	65.21	(1.60)	-2.39%
Total	80	$520.76	$520.71	($0.05)	-0.01%

Average Increase per Month $0.00

RATE 63	Proposed Phase 1	Proposed Phase 2
Basic Service Charge	$0.25	$0.333
Distribution Charge - all Dk	$1.028	$0.649
Cost of Gas	$4.3408	$4.3408

ATRIUM ECONOMICS

Ronald J. Amen

Managing Partner, Atrium Economics LLC

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time-of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

Bachelor of Science, Business Administration, Finance and Economics, University of Nebraska– Lincoln, 1978, United States

YEARS EXPERIENCE

42

PROFESSIONAL ASSOCIATIONS

American Gas Association

Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis; Litigation Support; Regulatory Support; Strategy; Utility Operations

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Policy, Strategy and Analysis

Western Export Group (2019)

In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canadian National Energy Board, Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system.

Regulatory Commission of Alaska (2019 – 2020)

Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc's acquisition of the Municipal of Anchorage d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)

Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

FortisBC Energy, Inc. (2016 – 2018)

Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC.

McDowell Rackner & Gibson Law Firm (2015 – 2016)

Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)

Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)

Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)

Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Resource Planning, Strategy and Financial Analysis

Fortis BC Energy, Inc. (2011)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2 003)

Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

Cost Allocation, Pricing Issues and Rate Design

Kansas City, KS Board of Public Utilities (2019 – 2020) (pending)

Provided expert witness testimony supporting the basis for a Green Energy Program, its objectives and overall benefits. Provide an assessment of how the program is aligned with best practices in design of Green Energy tariff programs nationally. Testimony also provided an assessment of how the program mitigates potential risks the to the Board of Public Utilities and protects against subsidization of other rate classes.

NW Natural (2018 – 2019)

Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)

Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)

Engaged by LG&E and KU to a conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)

Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas , Inc. subsidiary.

Westar Energy (2018)

Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which will incorporate the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently working with Tacoma Power for the potential incorporation of financial forecasting capabilities and revenue requirements development into the COSA model. Future project work involves working on the re-design of the general service and industrial rate schedules, economic development rate strategies, demand response rates, and other innovative rate programs.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities;
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions;
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA);
- Collected and reviewed data for cost-based fees including:
  - Application Fees
  - Non-Compliance Fees
- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs; and
- Performed modeling of rates under the FCC Model, the APPA model and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)

Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)

For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)

Represented clients in an ENSTAR gas general rate proceeding. Testimony discuss accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017)

Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in four general rate cases before the Indiana Utility Regulatory Commission.

Southwestern Public Service Company (Xcel) (2012)

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)

Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)

Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)

Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)

In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In a pending general rate case, Mr. Amen is sponsoring expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement.

Utility System Operations and Organizational Development

Philadelphia Gas Works (2017, 2020)

Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)

Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)

Engaged to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)

Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

SELECTED PUBLICATIONS / PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

"Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation," EUCI, January 22-23, 2020