MONTANA-DAKOTA UTILITIES CO.

Before the South Dakota Public Utilities Commission

Docket No. NG23 - ___

Direct Testimony

of

Ronald J. Amen

August 15, 2023

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

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. Atrium is a management consulting and financial advisory firm focused on the North American energy industry.

Q. Please describe Atrium's business activities.

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

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

Q. 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 25 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 in Appendix A.

Q. Have you previously testified before the South Dakota Public Utilities Commission ("Commission")?

A. No.

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 N, Statement O, and the following exhibits:

- Exhibit No.____(RJA-1), Proposed Revenue Allocation
- Exhibit No.____(RJA-2), Rate Schedule 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.

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 forecasted test year or some combination of historical and future costs. Where a forecasted 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, the costs of mains 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 Small Firm General, Small

Interruptible, and Large Interruptible customers. The costs related to these facilities from the following plant accounts were directly assigned to the Small Firm General, Small Interruptible, and Large Interruptible.

- Account 378 – Measuring & Regulating Equipment – General. Direct assignment to Small Firm General (Rate 70).
- Account 383 – Service Regulators. Direct assignment to Small Firm General (Rate 70), Small Interruptible (Rates 71 and 81) and Large Interruptible (Rates 82 and 85).

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 South 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.

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 five customer classes: Residential, Small Firm General, Large Firm General, Small Interruptible Sales and Transportation, and Large Interruptible Sales and Transportation.

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 27.8% of its investment in distribution mains as customer related and 72.2% 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. The zero-intercept method produced the

27.8% customer component used in the COSS. The minimum-sized unit method resulted in a 32.3% customer component.

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

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

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

Q. With respect to 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 weighted 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 results of 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 27.8% classification of distribution mains as customer related, used by the Company?

A. Yes. Applying the regression results for plastic mains of $5.43 and steel mains of $11.19 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 27.8% of the total investment in distribution mains, on a current cost (year 2023) 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 South 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 sixty-four years,1959 through 2022, 4.2 million feet out of approximately 7.9 million total feet or 53% of distribution mains installed in Montana-Dakota’s South Dakota service territory was 2-inch plastic pipe. The dominant pipe size for new distribution main installations by far is 2-inch plastic. Since 1959, the second most footage of installed distribution mains was 4-inch plastic pipe, approximately 1.3 million feet. The 2-inch plastic pipe analysis, adjusted downward to account for its load carrying capacity, yielded a minimum system result of 32.3%.

Q. Montana-Dakota’s distribution mains plant data for South Dakota indicates the installation of smaller sized pipe (1 ¼-inch) over the 64-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 – roadbeds, 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. 378 & 379 (Measurement & Regulator Station Equipment – General & City Gate), and 387 (Cathodic Protection Equipment) were classified and allocated based on the Design Day Peak allocator. The costs in Accounts Nos. 374 (Land & Right of Way), and 375 (Structures & Improvements) were classified and allocated based on the Distribution Mains and Measurement & Regulator Station Equipment allocator.

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

A. With one exception, General, Intangible, 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 Plant – Customer Care & Billing (CC&B) and PragmaCAD (PCAD) 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. For example, the treatment of Account No. 879 (Customer Installations Expense), 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) and 904 (Uncollectible Accounts). Meter reading expenses were allocated based on the total annualized number of customers weighted by meter size. 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 N.

A. Statement N, Schedule N-1, pages 1 – 5, provides a report titled 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 7.600 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, Small Interruptible Sales and Transportation, and Large Interruptible Sales and Transportation. The pro forma system rate of return of 0.01%, before allocation of the requested increase, is also shown on Schedule N-1. An example of the cost of service information provided on Schedule N-1, the resulting rate of return on rate base allocated to the residential class, served under Residential Service Rate 60, is (1.87%). A revenue increase of $6,403,545 would be required to bring the residential rate of return to the overall system average requested rate of return of 7.600 percent.

A summary of the results by the major rate classifications, Residential, Small Firm General Service, Large Firm General Service, Small Interruptible Sales and Transportation, and Large Interruptible Sales and Transportation is provided in Statement N, Schedule N-1, pages 6 – 7.

Statement N, Schedule N-2, pages 1 – 55, titled Embedded Class Cost of Service Study, provides the complete 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 the Allocation Factor Report, Statement N, Schedule N-3, pages 1-9.

The COSS is based on the South Dakota results of gas operations recorded for the 12 months ended December 31, 2022, as adjusted to reflect pro forma adjustments sponsored by Company witness Ms. Vesey.

Q. Please summarize the results of the COSS.

A. As shown in Statement N, Schedule N-1, the overall rate of return for South Dakota natural gas service is 0.01% at present rates, based on the results of gas operations for the 12 months ended December 31, 2022, adjusted for known and measurable changes. The returns by customer class at current rates are shown below:

- Residential Service (1.87%)
- Small Firm General Service (1.01%)
- Large Firm General Service 7.15%
- Small Interruptible Sales & Transportation 10.84%
- Large Interruptible Sales & Transportation 1.58%

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 $7,418,636 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.

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 (System Average)*, 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). 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.

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 Schedule 60), Small and Large Firm General Service (Rate Schedules 70 and 72), 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), Proposed Revenue Allocation, as *Scenario B: Narrow the Disparity of Revenue to cost ratios between the classes*. In the case of the Residential Service and Small Firm General Service classes, the revenue adjustments ensure their proposed rates will move class revenues very near to the COSS for the two classes. The proposed revenue increase to the Residential Service class will improve its revenue to cost ("R:C") ratio from 0.67 to 0.98. Similarly, the Small Firm General Service class will move from a R:C ratio of 0.68 to 0.98 as well. The proposed non-gas revenue increases to these two classes are 120% of the overall system average increase.

The Large Firm General Service class's R:C ratio under current rates is 0.98; therefore, the proposed revenue increase for this class is one-third of the system average increase, which raises the class R:C ratio to 1.10. The proposed 100% of the system average revenue increase for the Large Interruptible Sales & Transportation class will raise its R:C ratio from 0.73 to 1.01 of unity (1.00).

The COSS results for the remaining customer class, Small Interruptible Sales & Transportation Service, indicates a rate of return above the system average rate of return at both the Company's current and proposed ROR levels and was above unity under current rates. This would suggest the need for a modest revenue decrease of $18,520 in order to move this customer class to cost (*i.e.*, convergence of the resulting R:C ratio to Unity), as shown in Exhibit No.___(RJA-1) under *Revenues at Equalized Rates of Return*. However, the customer impact implications for the Residential Service and Small Firm General Service classes from the proposed revenue increases to these two classes has led me to conclude, in consultation with the Company, to refrain from a revenue reduction for the Small Interruptible Sales & Transportation Service class, or alternatively, exempting this class from a revenue increase. Instead, the proposed revenue adjustment of 9% of the system average increase will raise the class's current parity ratio from 1.12 relative to unity, to 1.15.

In summary, the Company's preferred revenue allocation approach resulted in meaningful movement of the Residential and Small Firm General classes revenue-to-cost ratios to within the range of reasonableness to unity or 1.00, while 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 revenue to cost responsibility movement, and reduction in the existing interclass rate subsidies, is desirable.

Q. Please discuss the information provided in Statement O.

A. Statement O, page 1 of 1, titled Revenues Under Current and Proposed Rates, presents summaries by customer rate schedule of the proposed revenue increase. This Statement displays the revenues under the present and proposed rates for each customer tariff rate schedule. The allocation of the total revenue increase of $7,420,480 to the respective rate schedules is presented in Statement O, page 1 of 1. The resulting revenue increase by rate schedule and corresponding percentage are also shown.

The allocation of the total target revenue increase to the respective rate schedules is presented on page 2 of Statement O, Schedule O-1, titled Allocation of Revenues. The pro forma 2023 billing determinants and the embedded cost of service by rate class prior to the proposed revenue increase are presented on page 1 of 8 of the Schedule. The target revenue increase as a percentage of total class revenues, including gas costs, range from 15.89% to Residential; 12.55% to Small Firm General; 2.56% to Large Firm General; 1.90% to Small Interruptible; and 6.08% to Large Interruptible, as shown on Schedule O-1, page 2 of 8. The remaining six pages of Schedule O-1, titled Rate Reconciliation, provide the derivation of the proposed rates for each Rate Schedule.

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 Schedule 60), Firm General Service (Rate Schedules 70 and 72); 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 O, Schedule O-1 . Following the revenue increases recovered through the Basic Service Charges, except for the Small Interruptible Sales & Transportation Service rate schedules, the remaining allocated revenue increases for the remaining rate schedules will be recovered in their respective volumetric Distribution Delivery Charge components. The Small Interruptible Sales & Transportation 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 rate schedules.

A. As seen on page 3 of Statement O, Schedule O-1, the Basic Service Charge under Residential Rate 60 is proposed at $0.55 per day which reflects an average monthly charge of $16.73, an increase of approximately $7.60 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 $0.82 per day, and $1.86 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 $24.94 and $56.58 respectively, representing an increase of $8.21 per month in the Basic Service Charge applicable to customers using meters rated less than 500 cubic feet per hour and an increase of $5.48 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 Service Rate Schedules 70 and 72 are included on page 4 of Schedule O-1.

The proposed Basic Service Charge applicable to Small Interruptible Sales (Rate Schedule 71) and Transportation (Rate Schedule 81) Service customers is $210.00 per month. This level of basic charge is near the total allocated customer related costs for the Small Interruptible Service class at $218.77; as such, 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 result in a decrease in the Distribution Delivery Charge for both Sales Rate Schedule 71 and Transportation Rate Schedule 81 customers. The rate calculations for the Small Interruptible Service Rate Schedules are included on pages 5 and 6 of Schedule O-1.

The proposed Basic Service Charge applicable to Large Interruptible Sales (Rate Schedule 85) and Transportation (Rate Schedule 82) Service customers is $370.00 per month, a $95.00 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 Company's fixed costs via fixed charges. The rate calculations for the Large Interruptible Service Rate Schedules 85 and 82 are included on pages 7 and 8 of Schedule O-1.

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 can be calculated in the accompanying Exhibit No.___(RJA-2), page 1 of 6, Residential Gas Service Rate 60 Bill Comparison, the portion of the typical residential customer's annual bill represented by the proposed increase in the average Basic Service Charge of $7.60 per month is approximately 12% of the total bill. The effect of raising the proposed Basic Service Charge by $0.25 per day, the equivalent of $7.75 per month in January, the month in which the most gas is typically consumed by residential heating customers, is only 6% of the total January bill. This is a relatively small amount. The commodity cost of gas[1] is 65% 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 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.

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[1] Montana-Dakota's proforma cost of gas in the COSS is $6.412 per Dk.

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

A. No.

VII. 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 66.3 dekatherms (Dk) per year is shown on page 1 of Exhibit No.___(RJA-2), Rate Schedule Bill Comparisons. The average monthly increase for this residential customer under the Company's proposed rate design is $8.70 or 15.90%.

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

A. The monthly and annual bill impacts for a typical Small Firm General customer using 130 Dk per year is shown on page 3 of Exhibit No.___(RJA-2), 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 $12.09 or 12.56%. The monthly and annual bill impacts for a typical Large Firm

General customer using 1,188.4 Dk per year is shown on page 5 of the exhibit. The average monthly increase for this Large Firm General Service customer under the Company's proposed rate design is $20.53 or 2.57%.

Q. Does this conclude your direct testimony?

A. Yes.