**BEFORE THE**

**PUBLIC SERVICE COMMISSION OF NORTH DAKOTA**

**DIRECT TESTIMONY OF**

**BRUCE R. CHAPMAN**
**CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC**

**ON BEHALF OF**

**MONTANA-DAKOTA UTILITIES CO.**

**TABLE OF CONTENTS**



11 PU-16-666 Filed 10/14/2016 Pages: 32
Prefiled Direct Testimony of Bruce R. Chapman with Exhibit BRC-1
Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc.

## I. INTRODUCTION

**Q. Would you please state your name and business address?**

A. My name is Bruce R. Chapman. My business address is 800 University Bay Drive, Suite 400; Madison, Wisconsin 53705. I am a Vice President with Christensen Associates Energy Consulting, LLC ("CA Energy Consulting").

**Q. Would you please describe your educational background and employment experience?**

A. I received a Bachelor of Arts degree from the University of Pittsburgh in 1976 and hold a Master of Arts (in fact, a Ph.D., all but dissertation) in Economics from the University of Wisconsin - Madison. I majored in Industrial Organization. I have been employed by three economic consulting firms. Since 1986, I have worked at Christensen Associates Energy Consulting or its parent, Laurits R. Christensen Associates, Inc., in positions of increasing responsibility. The focus of my work has been regulated utility costing – embedded and marginal – and pricing and rate design, both traditional and innovative. For a decade I have prepared, analyzed, and advised upon both cost of service ("COS") studies and COS methodology. I have supervised the design of our firm's most recent COS model and an associated rate design model, and I have applied our models in the service of clients. Additionally, I have undertaken COS studies making use of our clients' in-house models, and have provided advice on COS issues on numerous occasions. Recent projects have included evaluation of various utilities' COS methodologies. I testified in late 2013 in regulatory hearings on cost-of-service methodology issues before the Nova Scotia Utility and Review Board. Earlier this year I filed written testimony before the Public Utilities Commission of Ohio in support of the

Dayton Power & Light Company regarding their COS study, which was submitted as part of a general rate application. My resume appears as Exhibit BRC-1 of this testimony.

## II. PURPOSE OF TESTIMONY

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to present and explain the COS study filed by Montana-Dakota Utilities Co.("Montana-Dakota or "Company") in this proceeding.

**Q. Would you please describe your role in preparing the COS Study?**

A. The COS Study was conducted under my supervision and control. The COS model design originated with Montana-Dakota and I reviewed the Company's model for reasonableness. Montana-Dakota provided the financial data necessary to populate the model, as well as the original classification information and allocator designations. Montana-Dakota also provided fixed cost breakdowns by service level and metering information detail that supported the development of certain allocators. CA Energy Consulting reviewed Montana-Dakota's selection of allocators and advised the Company with respect to the development of classification calculations. Subsequently we reviewed all files and computations that develop classification shares and allocators. Additionally, CA Energy Consulting reviewed the functioning of the model. I supervised this activity. My conclusion is that the model records the utility's full costs and reliably computes costs allocated to the utility's various classes. As a result of my work with Montana-Dakota in preparing the study and its underlying model I adopt and sponsor the model and support the study results.

**Q. Are you sponsoring any statements with your testimony?**

A. Yes. I am supporting the following statements, which represent Montana-Dakota's COS study:

- Statement M,
- Statement M Schedule M-1, and
- Statement M Schedule M-2

**Q. Would you please summarize your testimony?**

A. Yes. In Section III, I provide an overview of the reasons for conducting a COS study, the steps involved in a study, and the ways in which the study is used. Section IV reviews issues in the definition of rate classes. Section V describes the allocation of generation and transmission costs. Sections VI and VII discuss the classification and allocation of distribution costs. Section VIII reviews the results of the COS study, referencing Statement O and the supporting schedules. Section IX presents conclusions.

## III. THE NATURE AND PURPOSE OF A COS STUDY

**Q. Please explain the basis of and need for a cost of service study.**

A. An electric COS study separates a utility's total electric investments, revenues, and expenses among the rate classes or groups within each jurisdiction. The primary goal is to identify the costs incurred by the utility in providing service to each group of customers. A study is necessary to enable a regulatory commission to review and evaluate the contribution made by each rate class within its jurisdiction. Montana-Dakota, like other electric utilities, maintains its books and records in accordance with the Uniform System of Accounts as directed by the Federal Energy Regulatory Commission ("FERC") and the Public Service Commission of North Dakota ("PSC" or "Commission"). This system of accounting does not immediately separate the company's investments, revenues, and expenses by rate class within the jurisdiction. A COS study performs this role. A thorough, well-performed COS study can be a useful (and often the primary) tool for determining the adequacy of current rates for each class of customers. For those rates that the study reveals to be inadequate at current tariff levels, the study can be an appropriate tool for determining what rate changes should be made to achieve revenue adequacy. Ultimately, a COS study establishes cost responsibility by rate class that enables the utility to determine just and reasonable rates. The COS study filed in this proceeding accomplishes this objective of separating costs by rate class groupings.

**Q. How are COS studies used in the regulatory process?**

A. A COS study is often used as a tool to determine earnings and cost recovery by customer group/rate class. The regulatory body can use these COS results to judge the adequacy of rates within the jurisdiction. The National Association of Regulatory Utility Commissioners ("NARUC") identifies the COS study as a basic tools of ratemaking, and it is used to attribute costs to different categories of customers based on how those customers cause costs to be incurred.

**Q. Once the COS study was completed, was it used by MDU in this rate filing?**

A. Yes. MDU examined the results of the study to determine how well each rate class's revenues were covering costs. Company Witness Aberle then used the data to develop the proposed target rate of return and rate design for each tariff class.

**Q. In preparing a COS study, is there a guiding principle that a utility should follow?**

A. Yes. The overall objective of a COS study is to assign or allocate costs fairly and equitably to all customers. This objective is accomplished when the resulting study reflects the principle of "cost causation." This principle states that those customers who caused a particular cost to be incurred by the company in providing service to them should be responsible for those costs.

When certain costs are readily identified with a particular customer group, the assignment of those costs to that group reflects cost causation, which is fair and equitable to all customers. However, it must be recognized that most parts of an electric system are planned, designed, constructed, operated, and maintained to serve all customers. These costs are referred to as "joint" or "common" costs. Joint or common costs must be allocated to customer groups based on the cost-causative nature, or "drivers" of the costs incurred, and the aggregate requirements and service characteristics of the customers that caused the costs to be incurred. By adhering to this fundamental and essential principle of cost causation, the utility strives to make the results of the COS study fair and equitable to all customers.

**Q. What are the major "drivers" that cause costs to be incurred?**

A. Costs are normally influenced by three factors that are observable for most customers. Cost causation can be viewed as: (1) demand-related – costs incurred to serve peak needs for electricity (kW); (2) energy-related – costs that vary with energy consumption (kWh); and (3) customer-related – costs that vary with the number of customers. Utilities classify each of their assets and expenses according to their cost-causative factors and then allocate each set of classified assets and expenses to rate class. Each of these three drivers has its own separate and appropriate allocators to spread respective costs to rate groups within the utility.

**Q. Would you please summarize the steps undertaken to perform a COS study?**

A. Typically, a COS study consists of five major steps. These steps are: (1) functionalization of the financial accounting data, (2) "levelization" of the data, (3) cost-causative classification of the financial costs, (4) assignment to rate classes of costs and revenues readily identified with specific classes, and (5) allocation of common costs. After completing these steps, one can observe how well customer groupings cover their cost to serve by comparing revenues with costs by tariff class.

**Q. What is the first step, functionalization?**

A. Functionalization is the subdivision of a utility's assets and costs into the main functions required to provide electricity to customers. Montana-Dakota follows the functional categories contained in the FERC Uniform System of Accounts, namely production, transmission, distribution, and general for gross plant and depreciation. Production, transmission, and distribution categories are used in both operation and maintenance (O&M) and depreciation expenses. In addition, there is a customer services (customer accounting, customer assistance, sales) function in O&M expenses.

**Q. Please describe the second step, levelization.**

A. Levelization is the process of disaggregating costs by the customers' voltage service levels. The service level designations are a means of identifying and associating investment and expenses with customers and their loads at established points of service. In general, the lower the voltage level of service required by the customer, the greater the cost of providing service, because additional equipment is necessary to deliver lower voltage service and additional load losses are incurred when stepping down the load to lower voltages. In principle, customers at higher voltage service levels are not responsible for the costs associated with service levels below them. For example, a customer at the primary distribution service level is not responsible for the costs of the secondary level.

**Q. At what voltage service levels are MDU's customers served?**

A. Montana-Dakota serves customers at secondary and primary distribution levels, and at the substation level, in which customers are connected directly to the primary voltage side of a substation. Representative voltage service levels for these groups of customers are: 1) secondary – 480 V or less; 2) primary – 2.4 to 13.8 kV; and 3) substation (*i.e.* service taken directly from the substation) – also 2.4 to 13.8 kV.

**Q. What is the next step, classification?**

A. Classification segregates costs into the three primary "cost-causative" characteristics of investment and expenses described above. Each type of cost is deemed to vary in response to changes in one or more of: energy consumed (kWh), peak demand (kW), and number of customers.

**Q. What is included in the assignment step?**

A. As noted above, if costs or revenues are the responsibility of certain customers or groups of customers, these costs can be assigned directly to the customers responsible for them.

**Q. What is the allocation step?**

A. Allocation is the process of dividing common costs (costs that cannot be assigned to specific customers) among rate groups. This process requires the development of allocators. An allocator provides the share of each type of costs for which each rate group bears responsibility.

**Q. Which jurisdictional tariff classes are identified in this COS study?**

A. The customer classes used in this COS study are Residential, Small General, Irrigation, Large General, Optional Time of Day General Service, General Service Space Heating, Small Municipal, Municipal Lighting, Municipal Pumping, Outdoor Lighting, Interruptible, and Interruptible Demand Response. Within several of these classes there are separate tariffs distinguished by voltage service level.

## IV. RATE CLASS DETERMINATION

**Q. Has Montana-Dakota retained its current rate class determination for COS or were changes in rate classes necessary?**

A. Montana-Dakota has largely retained its current rate structure, but has found it advisable to present Rate 31 for primary and secondary distribution levels because of the emergence of significant load at primary distribution within Rate 31 (Optional Time of Day General Service).

## V. ALLOCATION OF GENERATION AND TRANSMISSION COSTS AT MONTANA-DAKOTA

**Q. Is Montana-Dakota allocating generation and transmission (G&T) costs in the same manner as in past COS studies?**

A. No. In the COS study filed with the 2010 rate case, Montana-Dakota used the Average and Excess Demand (AED) allocator to allocate G&T costs. I have recommended that the Company use the twelve-month coincident peak (12 CP) allocator. This allocator computes a simple average of the demands at the time of system peak in each month of the year for each class in the North Dakota jurisdiction. The 12 CP allocator is then based upon the class shares of the total summed across classes.

**Q. Why are you recommending the use of the 12 CP allocator in preference to AED?**

A. Both allocators are recognized by the NARUC Cost Allocation Manual[1], among several other allocators, and utilities have broad discretion, typically, in selecting an allocation method. The 12 CP allocator, a well-established peak demand method of allocating G&T costs, is preferable if one views these costs as being driven by system coincident peak demands, as many experts do. In addition to being based upon the logical foundation of system peak demands throughout the year influencing G&T cost causation, the 12 CP possesses additional useful attributes. This includes recognition of the cost pattern of scheduled maintenance and alignment with FERC's preference for 12 CP, and OATT pricing.

---

[1] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992, Washington, D.C., P. 39*ff*.

Difficulties in calculating a reliable 12 CP allocator at Montana-Dakota led to the use of AED in the past. AED requires class annual kWh and annual estimated class noncoincident-peak demand, while 12 CP requires *monthly* coincident-peak values, which are more time consuming to acquire and depend upon the availability of reliable load research data. Montana-Dakota's load research data have improved substantially since 2010, and the 12 CP approach is now feasible. The AED allocator is an energy weighting method that is based on the belief, shared by some utilities, that investment in generation depends not just on meeting peak demand but on meeting overall energy (or average demand) needs. The approach is implemented by classifying costs according to system load factor. For example, if system load factor is 55%, then 55% of costs are deemed energy-related. The remaining share is allocated based on the excess of NCP over average demand.

A theoretical weakness of the AED approach arises from the questionable use of NCP as an indicator of G&T cost causation, when compared with the methodological soundness of CP. (Using a CP measure instead of NCP in the AED allocator computation produces an outcome identical to that of the underlying CP allocator.) This awkwardness, and another theoretical weakness relating to the illogical use of load factor to classify generation cost to energy and demand, makes AED less attractive than 12 CP, provided that the 12 CP method is computationally feasible.[2] Now that Montana-Dakota can develop a 12 CP allocator, the Company feels that it is appropriate to adopt this allocator. I concur that this reasoning is sensible and within the standards of industry practice.

[2] Alternative weighted energy approaches, such as the equivalent peaker method, rely explicitly on system planners' views of the uses and costs of various types of generation, rather than simply determining the cost split via the load factor proxy. This method is more data intensive than the AED approach, though. Please see the NARUC *Electric Utility Cost Allocation Manual*, p. 52.

## VI. CLASSIFICATION OF DISTRIBUTION COSTS AT MONTANA-DAKOTA

**Q. How do utilities typically classify distribution costs?**

A. Utilities usually view distribution costs as being driven by a combination of demand-related and customer-related factors. For some distribution cost accounts, classification is not an issue, since the cost can be related exclusively to peak demand or number of customers. For example, substation costs are generally regarded as demand-related, while meter costs are commonly viewed as customer-related. However, in other cases, distribution classification is complicated by recognition that both demand and customer numbers can play a role in causing costs. In particular, assets under FERC account numbers 364-368 must usually be studied in order to classify costs successfully. Those accounts cover poles, towers, and fixtures (364); overhead conductors and devices (365); underground conduit (366); underground conductors and devices (367); and line transformers (368).

**Q. What methods are used to classify these accounts?**

A. Two methods are typically used: "minimum-size" and "minimum-intercept" (or "zero-intercept"). The former classifies the costs of a hypothetical minimum-size version of the utility's distribution system capable of connecting to all customers as customer-related, then classifies all residual costs as demand-related. The analyst examines the assets of each account, identifying the smallest type of pole, conductor, etc., valuing this smallest unit and multiplying by the total number of units of that type. Comparison with the value of all the assets in the account yields the result.

The "minimum-intercept" method calculates the costs associated with zero loads by valuing the costs of all assets in an account and conducting regression analysis of cost on current-carrying capacity or demand rating to establish the cost of a zero-load system.

Each approach has its merits. The minimum-size approach is economical because the data are available and the computations are straightforward. The minimum-intercept approach makes use of cost information on assets of all sizes in each class and computes a zero-load estimate, as opposed to a minimum-load presumption generated by the minimum-size method. Both methods are acceptable to the industry, as may be seen by referencing the NARUC *Electric Utility Cost Allocation Manual*.[3]

**Q. What method does MDU use?**

A. MDU uses the minimum-size method for accounts 364 to 367 and the zero-intercept method to classify transformers (account 368). The Company's method for accounts 364 to 367 uses a modeling approach that creates representative one-mile minimum and normal underground and overhead systems, and then calculates the current replacement cost of each. The one-mile minimum underground and overhead systems are regarded as customer-driven systems, while the difference in cost between a normal and a minimum system is deemed demand-driven. This approach has been used by MDU in past COS studies in both North Dakota and other jurisdictions.

**Q. Is the one-mile minimum construct a reasonable representation of customer-driven cost?**

[3] See Chapter 6, Section II, pages 90-96.

A. Yes, it is, in my opinion. Industry practice offers no single best representation of a minimum system. The one-mile-of-circuit approach attempts to construct a realistic representation of an MDU circuit under two situations, and applies the standard minimum system logic that use of the smallest feasible equipment size to serve that circuit is an acceptable way to identify customer-driven cost. The approach differs slightly from another widely-used minimum system approach that scales each type of the minimum equipment cost up to the cost of system equipment inventories. MDU's approach is appealing due to its starting point of a hypothetical one-mile circuit that is a realistic proxy for circuits in MDU's service territory.

**Q. How does MDU apply the one-mile minimum system methodology in its COS study?**

A. MDU combines its customer and demand shares for accounts 364-367 based on weighted asset values for each account to derive single percentages for the combined accounts.

**Q. How does MDU create classification shares for account 368, line transformers?**

A. MDU uses the minimum- or zero-intercept approach for each of three types of transformer (single- and three-phase padmount transformers, and single-phase line transformers).[4] The weighted average of the three shares yields shares for the complete account.

**Q. Why does MDU use the minimum-intercept method for account 368, but the minimum system method for the other accounts described above?**

---

[4] In each case, the analysis makes use of the transformers that are both currently in use and likely to be reordered as replacements for aging line transformers to determine the zero-intercept value and then uses the entire asset base to calculate shares. This technical detail is adopted to avoid the need to develop replacement prices for transformer sizes that are not going to be reordered at the time that existing transformers of those sizes are to be replaced.

A. Line transformers are not readily included in the methodology based on the representative one mile of circuit. Also, line transformers offer, by their standard equipment types, a more readily developed zero-intercept analysis. This approach also repeats that used in the previous rate case.

The results of MDU's analysis appear in the table below.[5] The bolded values are inputs to the COS model. Note that, as with other utilities, FERC account 366, underground conduit, is assumed to have the same classification properties as underground conductors.

| FERC A/C | Account Name | Customer | Demand |
|---|---|---|---|
| 364 | Poles – Primary | 62.9% | 37.1% |
| 365 | Overhead Conductors | 51.4% | 48.6% |
| 367 | Underground Conductors | 56.9% | 43.1% |
| 364-367 | Weighted Average | **57.5%** | **42.5%** |
| 368 | Line Transformers | **69.4%** | **30.6%** |

**Q. Have you reviewed the information provided by Montana-Dakota on its minimum size and minimum-intercept methods?**

A. Yes. I reviewed each account's computations that were used to derive the classification results. Based on my experience, the computations are reasonable, and should be accepted by the Commission.

[5] Classification of FERC account 366, underground conduit, is based on analysis of other accounts. Such practice is common classification methodology.

## VII. ALLOCATION OF DISTRIBUTION COSTS AT MONTANA-DAKOTA

**Q. How do utilities typically allocate demand-related distribution costs?**

A. Utilities allocate demand-related distribution costs primarily by reference to class shares of noncoincident peak ("NCP") demand. Load research reveals each class's single maximum level of consumption over the course of a year. The 1 NCP allocator is simply each class's share of the sum of these values. (The "1" denotes the single annual maximum value.) Investment in distribution expenses is presumed to occur in response to the increase in peak demands of subgroups of customers on individual feeder lines, with such peak demands not necessarily corresponding in timing to system peak demands. Accordingly, measuring each subgroup's peak or, more feasibly, each class's peak, and then estimating the class's share in the sum of the peaks across all classes, is a reasonable way to judge responsibility for demand-related cost causation applying to distribution investment.

**Q. How does MDU allocate demand-related distribution costs?**

A. MDU applies the 1 NCP approach, in line with the practices of many other utilities. As with other utilities, the allocator has several representations based on the levelization of costs. Thus, the MDU COS model features two NCP allocators, one applicable at the generation level and another at the secondary service level. The "NCP – Generation Level" allocator is based on the peak demands of all customers and allocates demand-related costs associated with land, station equipment, poles, conductors, and conduit. The "NCP – Secondary Level" allocator is based on the peak demands of secondary distribution customers and allocates demand-related line transformer costs. The practice of using the 1 NCP allocator for such costs is common among utilities.[6]

**Q. Are you familiar with the development of MDU's 1 NCP allocators?**

A. Yes. I have reviewed their development and find them to be reasonable and acceptable for cost allocation.

**Q. How did MDU develop its 1 NCP allocators?**

A. MDU possesses load research data for most of its customer classes. For each of these classes, MDU developed sample usage, coincident peak and class noncoincident peak data for calendar 2015, then scaled the values based on billed kWh. The result is demand values that preserve observed load factors of the load research sample. Load research results are available to Montana-Dakota for about 92% of jurisdictional load. The classes making up the remaining 8% of load were each matched to a class for which interval data are available. Demand values were calculated that produce load factors identical to the class with which each class lacking interval data was matched. For the test year (2017), Montana-Dakota produced kWh forecasts and demand values that yielded load factors identical to those of the historical data.

**Q. Why do you characterize this process as reasonable?**

A. This application of load research data to generate demand-related allocators is conventional. It is consistent with other utilities' practices and my experience.

---

[6] These allocators apply to gross plant. Accumulated depreciation at MDU is allocated based on the resulting shares of gross plant of combined demand- and customer-related costs. Functionally, this matches the practice of classification of depreciation identically with gross plant and allocation using the same allocators as those used to allocate gross plant.

**Q. How do utilities typically allocate customer-related distribution costs?**

A. Utilities develop customer-related allocators that record the shares of customers by class, often weighted to represent cost variation across customer classes. For example, a utility might use customer numbers, weighted by meter cost in each class as a customer-related allocator of meter costs.

**Q. How does MDU allocate customer-related distribution costs?**

A. MDU uses allocators based on customer numbers, weighted by costs for certain cost categories, for various types of assets and expenses. The Company develops six customer-related allocation factors: customer numbers, customer numbers excluding lighting; customer meters, weighted by an index of meter costs; customer service drops, weighted by service cost; customer transformers, weighted by transformer cost; and customer accounts, weighted by the cost of customer support. The company's forecasts of test year customer numbers and meter numbers underpin these allocation factors. The development and application of these allocators is conventional.

## VIII. COST-OF-SERVICE RESULTS

**Q. Would you please discuss the schedules that you are sponsoring with your testimony?**

A. I am supporting three schedules. They are Statement M, Cost of Service by Component; Statement M Schedule M-1, Rate Base, Revenue and Expenses, by Class at Current Rates; and Statement M Schedule M-2, Allocation Factors. The first of these provides a summary for each rate class's projected test year rate base and revenue requirements for the class to meet the requested rate of return. The second schedule presents detail by cost and revenue component culminating in projected rate base and rate of return at current rates. The third schedule provides documentation of the allocation factors used to develop costs by class.

**Q. Would you please describe the contents of Statement M?**

A. Statement M, Cost of Service by Component, presents summary information setting out the revenue requirement at the requested rate of return for each class and cost-causative component of the class. for the twelve-month test period of calendar 2017. The schedule contains 16 pages, one for each rate class. The leftmost column of data provides jurisdictional data while the rightmost presents the total for each class. Other columns provide the cost-causative components: demand (segmented into production and transmission, and distribution; energy; and customer cost. The schedule develops operating income, adjusts for taxes, and derives revenue requirement. Projected billing units for each cost causative category and the resulting unit cost appear at the bottom of each page. For example, the first page displays the calculations for the Residential class (Rate 10). The class's projected rate of return before a rate increase is 3.817%. In contrast, the jurisdictional projected rate of return is 5.839%. Unit costs for the Residential class, summed across demand and energy, amount to $0.087 per kWh, and $19.70 per customer-month, assuming that a rate increase sufficient to earn to the parity rate of return occurs. (The actual rates, of course, will differ from unit costs, partly because the requested class rate of return may not match the average request.)

**Q. What does Statement M Schedule M-1 present?**

A. Statement M Schedule M-1, Rate Base, Revenue and Expenses, by Class at Current Rates, provides the core COS study results. The schedule is voluminous, consisting of 105 pages, and should be considered the source for background information to the first schedule. A sequence of panels presents rate base, revenues, and expenses, by component. Each page presents total data for the North Dakota jurisdiction as sponsored by Mr. Jacobson, the total for the rate class, and detail for the four cost causative factors. All information for each rate appears together, and requires several pages. The first pages provide rate base – gross plant and accumulated depreciation – and conclude with Net Electric Plant in Service. Revenues follow, with detail by type of charge. Expense detail – O&M, depreciation, and taxes – leads to Total Operating Expenses. Total Operating Income is the difference between total operating revenues and expenses. (Naturally, the difference between revenues and expenses for the total rate class is of interest, while the difference by cost causative factor is not immediately informative.)

**Q. What else is noteworthy in this schedule?**

A. Each page contains an Allocation Factor (an identification number) in the first column of data. This factor can be used as a reference in Schedule M-2 to identify how each line of the study was allocated. (Please see the description of that schedule below for more detail.)

**Q. What does Statement M Schedule M-2 present?**

A. As noted immediately above, Schedule M-2 presents the allocation factors used in the COS study. On the left side of each page, the allocation factor number and title appear, followed by two lines for each factor. The top line provides the numbers on which the allocation factor is based, while the bottom line presents the allocator shares themselves. As with the previous schedules, each rate class is segmented by cost causation factor, two demand factors being followed by an energy and a customer factor. Allocation factors 1 through 12 consist of the familiar energy, demand, and customer allocators used to allocate rate base. Following these are allocation factors that are derived from the cost allocation performed by allocators 1 through 12. For example, Allocator 14, Distribution Plant, is developed following allocation by the demand (4 and 5) and customer (7 through 12) allocators. Allocator 19, Line Transformers, is developed following the allocation of gross plant by allocator 5, NCP – Secondary Level (for demand-related cost) and allocator 11, Weighted Customer Transformers (for customer-related cost). This methodology is widely practiced in the industry.

**Q. How were these allocators selected?**

A. The allocation factors used in this COS study largely are retained from the 2010 study. CA Energy Consulting and MDU reviewed the various allocation factors to evaluate whether any needed modification. CA Energy Consulting concluded that the allocators largely comport with industry practice and/or have a common-sense basis. However, as the testimony above has noted, the review determined that one allocator ought to be changed: the AED allocator for G&T demand-related costs should be replaced by the 12 CP allocator. I recommend that the PSC accept this modification for the reasons stated above. That change has a secondary implication in that Allocation Factor 3, Demand/Energy for Wind, now utilizes 12 CP for the demand component of this mixed allocator.

**Q. Are there any other noteworthy changes in cost allocators or allocation?**

A. Yes, there is one such change. MDU subdivided its general, common and intangible plant costs for the first time in this COS study in an effort to improve the accuracy of cost allocation. There is one change in the list of allocators, the addition of allocation factor 6, Total Customers. Intangible plant costs (and depreciation of those costs) now consist of a customer care and billing (CC&B) component and a (larger) residual. CC&B costs are to be allocated based on allocation factor 6, Total Customers, while other intangible costs are to be allocated based on their original allocation factor number 13, Production, Transmission, and Distribution Plant. The use of the Total Customers allocation factor for CC&B appears to improve accuracy in cost allocation for these clearly customer-related costs.

**Q. Are you confident that these allocators are correctly applied by the model?**

A. Yes. CA Energy Consulting reviewed the model in detail and concluded that the allocators identified in the model utilize the proper allocator values and correctly calculate class shares.

**Q. What are the results of the embedded class cost of service study?**

A. The overall North Dakota electric rate of return based on projected 2017 results is 5.839 percent. The returns by customer class are as shown below:

| Customer Class | ROR (%) |
|---|---|
| Residential | 3.818 |
| Small General | 5.395 |
| Irrigation | (1.195) |

| | |
|---|---|
| Large General Primary | 7.580 |
| Large General Secondary | 8.416 |
| TOD Large General Primary | 4.198 |
| TOD Large General Secondary | 5.844 |
| Space Heating | 6.077 |
| Small Municipal | 2.701 |
| Municipal Lighting Primary | 13.080 |
| Municipal Lighting Secondary | 10.847 |
| Municipal Pumping Primary | 2.020 |
| Municipal Pumping Secondary | 4.070 |
| Outdoor Lighting | 11.879 |
| Interruptible Demand Response | 6.616 |

## IX. CONCLUSIONS

**Q. What are the conclusions of your testimony?**

A. Montana-Dakota's COS Study fairly and accurately presents the functionalization, classification and allocation of the utility's financial information to its retail customer classes. Reasonable and well established allocators are used in cost allocation. Classification percentages are derived in demonstrably reliable computations of cost shares for the major asset accounts. Classification for other accounts is consistent with industry standards. Additionally, the COS study reveals the current rate of return for the utility as a whole and for individual classes, based upon sound cost causation and provides essential information for guidance in rate setting.

**Q. Does this conclude your direct testimony?**

A. Yes.

# Bruce R. Chapman

RESUME

January 2016

## Address:

800 University Bay Drive, Suite 400
Madison, WI 53705–2299
Telephone: 608.216.7147
Fax: 608.231.2108
Email: brchapman@caenergy.com

## Academic Background:

All course work necessary for PhD, University of Wisconsin–Madison, 1981, Economics
MA, University of Wisconsin–Madison, 1979, Economics
BA, University of Pittsburgh, 1976, Economics

## Positions Held:

Vice President, Christensen Associates Energy Consulting, LLC, 2015-present
Senior Economist, Christensen Associates Energy Consulting, LLC, 2005–2014
Senior Economist, Laurits R. Christensen Associates, Inc., 1992–2005
Economic Analysis Consultant, Laurits R. Christensen Associates, Inc., 1988–1992
Research Economist, Laurits R. Christensen Associates, Inc., 1986–1988
Associate Consultant, Coopers & Lybrand Consulting Group, Economics Practice, Toronto, Canada, 1985–1986
Research Assistant, University of Wisconsin-Madison, 1980–1981
Research Analyst, Woods Gordon (Economics Group), Toronto, Canada, 1979–1980

## Professional Experience:

I assist clients in the electricity and natural gas industries to improve their costing and pricing capabilities. I advise clients in such areas of expertise as: cost-of-service analysis and rate design based upon established regulatory and market-based principles; innovative rate design including demand response products, renewables pricing, fixed billing, and other market-based retail pricing products; load forecasting and load research analysis. I supervise and conduct analysis of costing and pricing issues for utilities, regulators, customers and other industry stakeholders. Additionally, I have supervised the development of software required for the implementation and support of innovative retail products. Examples include cost-of service and rate design models to support rate applications, and models to predict customer tariff choice and price response. I regularly present costing and pricing issues and concepts at industry conferences and workshops.

**Major Projects:**

Provided pricing and revenue recovery guidance to a Caribbean utility.

Provided guidance to a Southeast Asian utility in the design of time-of-use rates. Guidance included instruction in simulation of price response.

Directed a cost-of-service study for a large distribution utility.

Assisted a utility to adjust its costing and pricing methods following addition of significant new generation and transmission assets.

Assisted a utility to merge rates of two separate service territories following a corporate merger.

Reviewed a natural gas distribution utility's proposal for a commodity hedging arrangement.

Assisted in developing an electric vehicle tariff for a Midwestern utility.

Assisted in an evaluation of economic development and load retention rates for a Midwestern utility.

Led an evaluation of a Midwest utility's residential time-of-use rate in comparison with other TOU designs and current marginal costs. Evaluated means by which participation could be increased.

Participated in an evaluation of the merits of a special contract for a large customer of an Eastern utility.

Conducted an analysis of the relative cost-of-service implications of creating a separate class for a specialized subset of customers from an existing large customer class.

Assisted a Great Plains utility to develop a renewable tariff for large industrial customers.

Managed a project that assisted a Great Plains public service commission staff to evaluate natural gas utility submissions for safety-related cost recovery via new riders.

Participated in a load research data development project for a Midwestern utility, including sample design and selection, and class interval load profile development.

Conducted an analysis of the cost implications for a Caribbean utility of introducing LED street lighting.

Developed generic cost-of-service and rate design models for use in client rate cases.

Customized company cost-of-service and rate design models for an Asian utility. The project also included support for marginal cost capability development.

Led a rate case preparation process for a Southeastern utility that included load and energy forecasting, development of revenue requirements, and support for cost of service and rate design.

Participated in a Midwest utility's rate case by reviewing current mass market time-of-use and other rate designs and recommending modifications.

Collaborated in a review of a large Canadian utility's cost-of-service methodology, including a public review process with stakeholders. Testified before regulator regarding recommendations.

Conducted an assessment of a Great Plains public power utility's plans for three pricing concepts: green power, economic development rates, and unbundled retail pricing to facilitate customer choice.

Assisted a distribution utility to review aspects of its distribution cost allocation methodologies by conducting a survey of methodologies across a number of electric utilities.

Assisted a state energy office to review ways in which the state could improve its record of energy efficiency program achievements, as recorded by the ACEEE Scorecard.

Collaborated in the development of rate redesign alternatives for a utility's real-time pricing program structure.

Collaborated in the review of the potential for a Canadian utility to introduce a fuel adjustment mechanism.

Conducted an analysis of probable migration of customers to new time-of-use electricity programs offered by a southeastern utility.

Evaluated the accuracy of an electric utility's fixed bill offer algorithm and recommended modifications.

Led a project which conducted a review of an electric utility's avoided cost calculation and the application of those costs in energy efficiency reviews.

Managed and participated in reviews of rate and gas cost adjustment applications for a Great Plains public service commission's gas division.

Conducted a cost-of-service and rate design study for a Caribbean utility in preparation for a rate submission.

Supported review for an industrial customer group of a large filing by a utility, focusing on non-bypassable riders.

Managed a gas cost review process for a Great Plains regulatory agency.

Analysis of smart grid pricing issues for a Great Plains public power utility.

Contributed to load research sample development for an investor-owned utility.

Managed a review of a large electric and gas utility's costing methodologies.

Managed a cost-of-service and rate design study for a Caribbean utility.

Conducted analysis of distribution costing practices at a large Midwestern investor-owned utility.

Development of a time-of-use rider for two electric utilities.

Management of a study of interruptible pricing program improvements for a large Midwestern utility.

Management of a comprehensive cost-of-service and rate design study for a Caribbean utility.

Strategic pricing for a large hydro-dominated utility.

Evaluation of the net economic benefits of alternative power supply strategies: coal vs. renewables and energy efficiency.

Load forecasting project for a medium-sized electric utility with significant industrial load.

Analysis of alternative means of net metering.

Evaluation of alternative demand response programs for a municipal utility.

Analysis of treatment of margins from real-time pricing.

Analysis of a natural gas energy conservation funding mechanism.

Design and pricing of a small customer Time-of-Use program.

Evaluation of cost of capital for a small Caribbean utility.

Risk pricing of a long-term customer choice retail contract.

Evaluation of response by small customers to fixed billing programs.

Evaluation of response by medium-sized customers to a banded fixed billing program.

Cost-of-service project including marginal cost and traditional cost basis.

Preparation of load research survey sample via stratified random sampling.

Design and pricing of a Critical Peak Pricing product

Evaluation of residential customers' propensity to adopt a voluntary Time-of-Use product

Pricing of a fixed bill product for a new service territory based on response elsewhere

Evaluation of peak period response to a fixed billing product

Development of an electric utility fuel forecast

Customization of fixed bill software for use at a utility site

Design and pricing of a Banded Fixed Billing product.

Long-term wholesale power procurement for an electric utility.

Report on Adoption of Variable Pricing contracts in deregulated retail electricity markets.

Development of Fixed Bill software to generate offers and monitor customer behavior.

Quantitative evaluation of net benefits of demand response programs.

Quantitative evaluations of customer response to fixed billing.

Design and pricing of several pilot and permanent fixed-bill programs.

Development of Efficient Tariff Prices via Marginal Costing.

Analysis of Market Data Available to Estimate Marginal Cost of Reliability.

Evaluation of Risk of Fixed Billing Based on Customer Response.

Cost Allocation Analysis for Rate Case Filing.

Analysis of Customer Response to Fixed Billing.

Fixed Bill Scoping for a Natural Gas Provider.

Analysis of Risk Implications of Fixed Billing for an Electric Utility.

Strategic Assessment of an Electric Utility's Retail Tariff Portfolio.

Guaranteed Bill Product Design and Risk Assessment.

White Paper on Interruptible/Curtailable Service.

Marginal Cost-Based Cost of Service Development.

Software Scoping for Self-Designed Products.

Flat Bill Offer Software Development.

Comprehensive Rate Repricing.

RTP Price Hedging Product Development.

Retail Pricing Under Competition Conference.

Rate Optimization Plan.

Fixed Bill Product Development.

Weather Hedge Evaluation.

Real-Time Pricing Product Development.

Workshop: Creating a Diversified Retail Pricing Portfolio.

Product Mix Business Plan.

Prepared material for testimony in Federal District Court on Real-Time Pricing.

Risk-Based Pricing Workshops.

Survey of New Electricity Market Players.

Analysis of Fixed Bill Products.

Strategic Pricing Plan for a Midwestern Utility.

Product Mix Analysis for Small Customers.

Real-Time Pricing Workshop.

Innovative Pricing and Marginal Costing for a Co-op.

Real-Time Pricing with Multiple Options.

Real-Time Pricing for a G&T and its Co-ops.

Product Mix Analysis for Large Customers.

Real-Time Pricing Service Design for Commercial Customers.

Advanced Service Design Workshop.

Real-Time Pricing Program for a Midwestern Utility.

Evaluation of Customer Response to Real-Time Pricing.

Real-Time Pricing Program Development for an Eastern Utility.

Two-Part Pricing Service Design.

Real-Time Pricing Regional Workshops.

Real-Time Billing Program Support and Revision.

Electricity Efficiency Programs.

Real-Time Pricing Program Redesign for an Eastern Utility.

Real-Time Pricing Implementation for a Canadian Utility.

Real-Time Pricing Practitioners' Workshop.

Real-Time Pricing for a Canadian Utility.

Customer Evaluation of Real-Time Pricing.

Review of Competitive Pricing Strategies.

Evaluation of Process of Marketing Real-Time Pricing.

Review of Methods for Distinguishing Customer Response to Rate Change.

Real-Time Pricing Rate for a Southern Utility.

Review of Accounting and Incentives for a Real-Time Pricing Rate.

Analysis of Load Impact of Priority Service Alternatives.

Benefit/Cost Analysis of an Integrated Energy Management System.

Benefit/Cost Analysis of Marginal Cost-Based Rates for DSM Integrated Resource Plan.

Impact Evaluation of Curtailable Electric Service.

Survey of Households Who Were Candidates for Voluntary Time of Use Rates.

Audit of Energy Management Software.

Real-Time Pricing Rate for a Large Northeastern Public Utility.

Software Design for Real-Time Pricing.

Improved Approaches to Estimating Benefits of DSM Programs.

Load Shapes Assessment Program.

Fuel Purchase Contract Study.

Evaluation of the Effects of Canadian Energy Policy.

Evaluation of Energy Conservation Programs.

**Professional Papers:**

"Pricing of Renewable Energy Made Difficult by Policy Challenges", *Natural Gas & Electricity*, January 2016.

"Hedging Exposure to Volatile Retail Electricity Prices", *The Electricity Journal*, June 2001 (with Ahmad Faruqui, Dan Hansen, and Chris Holmes).

"A Survey of Real-Time Pricing Programs", *The Electricity Journal*, August–September 1993 (with Juliet Mak).

"Real-Time Pricing: DSM at Its Best?", *The Electricity Journal*, August 1990 (with Tom Tramutola).

**Conference Presentations:**

"Net Metering and Solar Energy Pricing", pre-conference workshop at EUCI's Net Energy Metering and Utility Solar Rates Summit, July 2016.

"Pricing the Purchase of Renewable Energy," post-conference workshop at EUCI's 4th Annual Southeast Clean Power Summit, March 2015.

"Pricing Perspectives of Regulated Utilities on Solar Power," EUCI's Net Metering 2.0 and Utility Solar Rates Conference, Anaheim, CA, January 2015.

Cost of Service and Rate Design; Current Utility Costing and Pricing Challenges; Pricing Renewable Energy; Feed-in Tariffs and Demand Response Alternatives to Supply. Presentations to the Wisconsin Public Utility Institute's Energy Utility Basics Course, 2009–2015.

"The Bill Please," university course and public presentation within the "Decoding the Energy Industry" series; Wisconsin Public Utility Institute, 2014.

Electric Rate Design Principles and Designs (with Dr. Stephen Braithwait), and Pricing Renewable Resources; presentations to the Rate Design and Regulation Workshop, Wisconsin Public Utility Institute, Madison, Wisconsin, 2014.

"Customer Response to Dynamic Pricing: Who Responds and How?," EUCI's Smart Ratemaking Conference, Oct. 2009, Los Angeles; with Dr. Steven Braithwait.

Cost-of-Service, preconference workshop, EUCI's Smart Ratemaking Conference, Oct. 2009, Los Angeles.

Critical Peak Pricing: Valuation and Viability, presented at AESP's Innovations in Retail Pricing Conference, Chicago, IL, May 17, 2006.

Georgia Power's FlatBill Program, Risks and Returns, presented, with Monamee Adhikari, Georgia Power Company, at AESP's Innovations in Retail Pricing Conference, Chicago, IL, May 17, 2006.

Retail Pricing for Competitive Power Markets, six presentations on retail pricing and unbundling; Infocast conference February 28-March 2, 2001.

Retail Products and Pricing Under Competition, presented at the Canadian Electricity Association's seminar: Setting Up for New Energy Regulation, April 19, 1999.

Using Risk as the Maker of Prices: Risk-Based Pricing, presented at Infocast's conference: Power Industry Retail Pricing, June 23–25, 1999.

"Designing a Retail Pricing Product Mix for a Competitive Market: A C-VALU Case Study," presented at EPRI's Innovative Pricing Conference, Washington, DC, June 18, 1998, (with Kathleen King and David Kulha).

"Retail Products & Pricing in the Competitive Era," presented at IBC Conference: Successfully Implementing Retail Access, Washington, DC, April 27, 1998.

"Risk-Based Pricing: Making Money in Competitive Markets," EMACS Conference, Atlanta, Georgia, October 14, 1997, (with A. Faruqui, EPRI).

"Real-Time Pricing: Becoming Competitive Before Competition," presented at IBC Conference: Successfully Implementing Retail Profit Projects, Atlanta, Georgia, February 24, 1997, and Las Vegas, Nevada, July 17, 1997.

"Effective Retail Product Design for a Competitive Market," IBC Conference: Developing, Negotiating and Contracting Retail Electricity Prices, Atlanta, Georgia, February 24, 1997, (with Kathleen King).

"Innovative Pricing and Data Requirements," presented at the AEIC Load Research Conference, Washington, DC, August 4–6, 1995.

"Lessons Learned and the Path Forward," presented at EPRI's National Conference on Achieving Success in Evolving Electricity Markets, Atlanta, Georgia, October 10–12, 1995 (with Kathleen King).

"A Real-Time Pricing Primer: Service Design for a Competitive Market," presented at the Missouri Valley Electric Association Marketing Division Conference, Kansas City, Missouri, October 13, 1994.

"Real-Time Pricing: Service Design for a Competitive Market," presented at the American Public Power Association workshop, Scottsdale, Arizona, September 28, 1994.

"Customer Response to Real-Time Pricing: Results from Current Experiments," presented at the 6th National Demand-Side Management Conference, Miami Beach, Florida, March 25, 1993.

"Electricity Pricing Innovations for Retail Sales," presented at the Energy Utilities and Regulation Course, Wisconsin Public Utilities Institute, September 13, 1990; revised and presented again in 1992.

"Innovative Pricing in DSM: Recent Field Tests of Real-Time Pricing," presented at the Energy Demand-Side Research Seminar Series, University of Wisconsin-Madison, April 4, 1990 (with D. W. Caves).

**Testimony:**

Panelist in Cost-of-Service Methodology review hearings on behalf of Nova Scotia Power, before the Nova Scotia Utilities and Review Board, proceeding NSUARB-NSPI-P-892, Matter No. M05473, December 2013.