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January 31, 2023

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North Dakota Public Service Commission
600 E. Blvd. Ave. Dept. 408
Bismarck, ND 58505-0480


Re: Montana-Dakota Utilities Co., Case No. **PU-22-194**

Attached are an original and seven copies of the **Direct Testimony of Ron Nelson** in the above referenced matter.

Please feel free to contact me with any questions or concerns.

Sincerely,

TSCHIDER and SMITH



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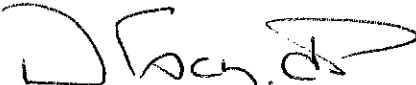
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TABLE OF CONTENTS

I.	INTRODUCTION	3
II.	COST OF SERVICE STUDY	5
A.	The Influence of Economic Incentives on Cost of Service Studies	6
B.	Objectives and Background	8
C.	Basic Customer Approach.....	12
D.	MDU's Minimum System Approach.....	17
i.	Analysis of MDU's Minimum System Approach	21
III.	REVENUE APPORTIONMENT.....	27
IV.	RATE DESIGN	30
A.	MDU's minimum system study is not a valid justification to increase customer charges and would result in charges that do not align with cost causation Error! Bookmark not defined.	
B.	High customer charges harm customers, including low-usage and low-income customers as well as those investing in energy efficiency and distributed technologies Error! Bookmark not defined.	
C.	The Company's justification for its proposed customer charge increase lacks theoretical and analytical support.	40
V.	SUMMARY OF RECOMMENDATIONS	43
VI.	CONCLUSION.....	43

SCHEDULES

Schedule	Description
Schedule AARP-REN-1	Resume
Schedule AARP-REN-2	NASUCA Customer Charge Resolution

I. INTRODUCTION

1 **Q. Please state your name, title, and position.**

2 A. My name is Ronald Nelson. I am a Senior Director at Strategen Consulting located at 10265
3 Rockingham Dr. Suite #100-4061, Sacramento, CA 95827.

4 **Q. On whose behalf are you testifying?**

5 A. I am testifying on behalf of AARP.

6 **Q. Please describe your formal education and professional experience.**

7 A. I am currently a Senior Director at Strategen Consulting. The Strategen team is nationally
8 recognized for its thought leadership and deep expertise in regulatory innovation,
9 performance-based regulation, rate design, renewable program development, grid
10 modernization, new grid technologies, gas decarbonization, and electric vehicles (“EVs”).
11 During my time at Strategen, I have worked with numerous consumer advocates,
12 nongovernmental organizations, utilities, and commissions on issues related to cost-of-
13 service modeling, rate design, grid modernization, distributed energy resource valuation
14 and integration, and performance-based regulation.

15 Before joining Strategen in early 2018, I worked for the Minnesota Attorney
16 General’s Office for almost five years, where I led that office’s work on cost of service,
17 rate design, renewable energy program design, performance-based regulation, and utility
18 business model issues. Before that, I worked for two universities and the United States
19 Geological Survey as an economic researcher. I have a Master of Science from Colorado
20 State University in Agriculture and Resource Economics, and a Bachelor of Arts in
21 Environmental Economics from Western Washington University where I also minored in
22 Mathematics.

1 **Q. Have you previously testified before state regulatory bodies?**

2 A. Yes. I have testified in over 50 proceedings in Minnesota, Michigan, Ohio, Pennsylvania,
3 Oklahoma, Utah, Massachusetts, Maryland, Maine, Indiana, New Hampshire, and
4 Vermont. The issues covered in these proceedings include marginal and embedded cost of
5 service studies, revenue apportionment, rate design, load management, renewable program
6 design, fuel clause adjustments, formula rates, decoupling, performance-based regulation,
7 multi-year rate plans, performance metrics, distributed energy resource (“DER”)
8 interconnection, DER compensation, DER integration, pilot frameworks, automated
9 metering infrastructure, prudence review, distribution system planning, capital investment
10 plan review, and smart inverter specifications.

11 I have also assisted with testimonies and regulatory analysis in Hawai’i,
12 Washington, D.C., Maryland, Minnesota, Massachusetts, California, North Carolina,
13 South Carolina, Iowa, Kentucky, Georgia, Washington, and the Federal Energy
14 Regulatory Commission (“FERC”).

15 A summary of my resume is attached as Schedule AARP-REN-1.

16 **Q. Have you previously testified before the North Dakota Public Service Commission?**

17 A. No.

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

19 A. My testimony focuses on analyzing MDU’s approach to cost classification and allocation,
20 the Company’s revenue apportionment proposal, and the Company’s proposal to increase
21 its residential monthly fixed customer charge.

22

23

1 **Q. Provide a summary of your recommendations.**

2 A. I recommend that the Commission apply the basic customer approach as a basis for
3 informing rate design and revenue apportionment. I also recommend that the Company's
4 approach to revenue apportionment cap increases to the revenue requirement for any given
5 class at 20% and limit increases to classes above parity to 90% of the system average
6 increase. Finally, I recommend that the Commission reject MDU's proposal to dramatically
7 increase its residential basic customer charge.

8 **Q. How is your testimony organized?**

9 A. In Section II, I contrast two approaches to cost classification and allocation: the basic
10 customer approach (which I recommend) and the minimum system approach (which MDU
11 utilizes). I show not only that the basic customer approach is more theoretically sound, less
12 subjective, and supported by reliable references and state policies across the country, but
13 that the Company's minimum system study suffers from substantial computational flaws
14 that fail to reflect cost causation principles.

15 In Section III, I review the Company's approach to revenue apportionment and
16 present the results of an alternative approach to apportionment based on my
17 recommendations.

18 In Section IV, I focus on the consequences of applying MDU's flawed minimum
19 system study to rate design. Specifically, I demonstrate that MDU's minimum system study
20 is not a valid justification for increasing the residential basic customer charge and that
21 MDU's proposed increase does not align with cost causation and would harm certain
22 residential customers. I also show that MDU's proposal contradicts the growing need to
23 incentivize flexibility in a grid marked by an increasing penetration of variable renewable

1 resources, and that MDU’s arguments for its proposal lack theoretical and analytical
2 support.

3

II. COST OF SERVICE STUDY

4 **Q. What is the purpose of this section of your testimony?**

5 A. In this section, I summarize the process of performing a Cost of Service Study (COSS) in
6 order to build a foundation for how a COSS is used to inform rate design as discussed in
7 Section IV of my testimony. I also identify several theoretical and computational flaws in
8 MDU’s approach to classifying customer-related costs, and recommend that the
9 Commission base rate design decisions on the basic customer approach for cost
10 classification and allocation. The basic customer approach is theoretically sound, less
11 subjective, and supported by reliable references and state policies across the country.

12

A. The Influence of Economic Incentives on Cost of Service Studies

13 **Q. Before you discuss the details of a COSS, please explain how economic incentives may
14 influence cost studies.**

15 A. When evaluating cost studies and the rate designs they inform, decision-makers should
16 consider how the economic incentives of utilities can impact assumptions within utility-
17 sponsored cost of service studies. It is important for decision-makers to understand how a
18 utility’s economic incentives may not always align with public policy goals and ratepayer
19 interests, so that decision-makers can evaluate cost of service modeling and rate design
20 proposals more effectively.

1 **Q. Please provide examples of where a utility's economic incentives may not align with**
2 **policy goals or ratepayer interests.**

3 A. There are two interrelated issues that can impact the utilities' perspective when
4 conducting cost studies.

5 First, the price elasticity, or sensitivity, of demand and variability of demand for
6 electricity differs across customer groups. The elasticity of demand measures how much
7 a consumer changes their electricity consumption given a change in its price. In many
8 instances large customers have more elastic demand than residents, meaning that large
9 customers will decrease their demand for electricity more than residents following an
10 equivalent price change, all else constant. Additionally, commercial and industrial loads
11 are often more responsive to economic fluctuations, making their load and associated
12 revenues more variable over time. These relationships suggest that utilities can benefit
13 financially from shifting costs from large to residential customers. This presents the
14 utility with an incentive to shift subjective cost allocations in the cost of service study
15 (and there are many in cost studies) to classes with less elastic and variable demand.

16 Second, third-party services can act as substitutes for utility services.

17 Traditionally, electric utilities have not faced competition on the distribution system.
18 Currently, technological improvements, such as solar plus storage, are providing service
19 opportunities that compete with those provided by the utility because those technologies
20 provide an alternative to utility-distributed electricity. In general, the presence of this
21 competition impacts utility incentives in many ways, potentially prompting them to take
22 actions to make their services more cost competitive through otherwise inefficient rate
23 design changes.

1 **Q. How do the economic incentives of a utility impact cost studies in practice?**

2 A. The utility perspective is largely informed by its economic incentives. For this reason,
3 when subjective determinations are made within a cost of service study or rate design,
4 utilities are likely to make assumptions that benefit their bottom line – as would any for-
5 profit business in a similar position. This can be especially problematic in cost studies
6 and rate design because each process involves numerous subjective assumptions. I
7 provide examples of subjective decisions made by MDU below.

8 **Q. Why are you highlighting these perverse economic incentives for decision-**
9 **makers?**

10 A. My goal is to ensure that decision-makers understand the economic incentives that
11 influence the perspectives a utility shares in regulatory proceedings and when it
12 constructs cost of service models. My goal is not, however, to demonize the utility, which
13 is simply responding to the regulatory framework and the resulting economic incentives
14 in which the Company operates. For this reason, creating a more effective regulatory
15 framework is fundamental to better aligning the economic incentives of a utility with the
16 needs of its customers.

17
18

B. Objectives and Background

19 **Q. What is the purpose of a COSS?**

20 A. The purpose of a COSS is to decipher, with as much detail and accuracy as possible, which
21 customer class caused the utility's various embedded costs associated with providing
22 service.

1 **Q. How is a COSS performed?**

2 A. A COSS has three general steps. First, costs are functionalized into various categories.
3 Second, costs are classified as energy costs, demand/capacity costs, or customer costs.
4 Lastly, the costs are allocated to the various customer classes using allocators related to
5 energy, demand/capacity, or customer characteristics.

6 **Q. How are costs functionalized?**

7 A. Public utilities are required to maintain records in accordance with the Uniform System of
8 Accounts as designated by the Federal Energy Regulatory Commission (“FERC”). These
9 accounts assign costs by various functions, such as generation, transmission, and
10 distribution. The purpose of functionalizing costs is to aid in determining which customers
11 are jointly or solely responsible for various costs.

12 Many utilities also sub-functionalize costs by voltage level. For example,
13 distribution costs can be sub-functionalized into primary and secondary voltages. Sub-
14 functionalizing by voltage level adds more detail to the COSS and improves the accuracy
15 of assigning costs when done properly.

16 **Q. How are costs classified?**

17 A. After a utility’s costs are functionalized, they are then classified as either energy, demand,
18 or customer costs based on cost causation. Costs classified as energy costs are those that
19 fluctuate on a customer class’s energy usage, measured in kilowatt-hours (“kWh”).
20 Demand costs are those costs that fluctuate based on a customer class’s contribution to
21 peak demand, measured in kilowatts (“kW”). Finally, customer costs are those required to
22 provide service to customers, regardless of whether the customers consume electricity or
23 not. Specifically, the NARUC Electric Manual defines a customer cost as “costs that are

1 directly related to the number of customers served.”¹ In other words, the utility incurs
2 customer costs based directly on the number of customers on its system, rather than on the
3 amount of energy they consume or when they consume it.

4 **Q. How are costs allocated once they have been classified?**

5 A. Costs are allocated to customer classes based on each class’s contribution to the particular
6 cost. For example, if the company spends the same amount of time and money on each
7 customer location, regardless of class, then it is appropriate to allocate that cost based on
8 the number of customer locations. This result stems from the fact that the number of
9 customer locations causes these costs to be incurred, rather than a customer’s electricity
10 consumption or any other factor.

11 **Q. How are the appropriate approaches to classification and allocation determined?**

12 A. Classifications and allocations are informed by cost causation. Cost causation is based on
13 the notion that the customer, or set of customers, that caused a certain cost should pay for
14 the cost. To determine cost causation, analysts often rely on economic theory and power
15 system engineering considerations. In this testimony I contrast three different methods for
16 classifying and allocating the costs of the distribution system: the basic customer approach
17 (which I recommend) and the minimum system approach (which MDU adopts and includes
18 two different methods: the minimum size and zero intercept methods).

19 **Q. What is the basic customer approach?**

20 A. According to the basic customer approach, only costs that can be traced to a specific
21 customer should be assigned as customer costs, because those are the only costs that vary
22 based on the number of customers in a class. Under this theory, the costs of the conductors

¹ National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, at 20 (1992) (hereinafter “NARUC Electric Manual”).

1 and transformers cannot be attributed directly to a customer, because adding one customer
2 to the system would not increase these costs. Instead, the basic customer approach
3 recognizes that the distribution system is built to serve peak demand, and so its costs should
4 be classified as demand-related. The basic customer approach has been utilized by
5 commissions to inform monthly customer charges for residential customers.

6 **Q. What is the minimum system approach?**

7 A. The minimum system approach reasons that the costs of the capacity in the distribution
8 system are caused by peak demand and should be classified as a demand cost. Some of the
9 costs, however, are related to connecting a customer to the “minimum system,” a
10 distribution system with little or no capacity. Because this fictitious minimum system has
11 no capacity, the cost to connect a customer should be the same and would vary based on
12 the number of customers in a class and therefore it is argued that such demand costs should
13 be classified as a customer cost. The cost of the minimum system can be estimated in
14 several ways, including the minimum size and zero intercept methods.

15 **Q. Which distribution classification approach do you think should be considered by the**
16 **Commission in this case?**

17 A. While there are arguments that support each of the approaches discussed above, the basic
18 customer approach most accurately reflects cost causation and is less subjective. In
19 addition, as I demonstrate below, MDU’s Minimum System approach relies on a flawed
20 methodology that does not reflect cost causation. For this reason, I recommend that MDU’s
21 proposed rate design reflect a COSS model that utilizes the basic customer approach.

22

C. Basic Customer Approach

1 **Q. Please explain why classifying and allocating distribution system costs can differ**
2 **between COSS models.**

3 A. As stated by regulatory economist Charles Phillips, "[w]hen the same plant or equipment
4 is used to provide several types of service, there is no one correct way to allocate these
5 costs among the different units of service. Any method of apportionment is subject to
6 dispute."² This statement is true for classifying and allocating distribution system costs as
7 well. Therefore, various models incorporate different mechanisms to determine how the
8 costs of the distribution system are classified and allocated.

9 **Q. How would a COSS utilizing the basic customer approach differ from MDU's**
10 **proposed COSS in this case?**

11 A. A basic customer COSS differs in only one way from MDU's minimum system COSS—
12 it classifies distribution system costs differently. Specifically, the basic customer approach
13 classifies FERC accounts 364-368 (referred to generally as "distribution system") as 100
14 percent demand related and FERC accounts 369-370 as customer related, while the
15 minimum system approach most commonly classifies FERC accounts 364-369 as both
16 demand and customer related. MDU's minimum system COSS classifies meters and
17 service lines, FERC accounts 369 and 370, as 100 percent customer related and then the
18 Company also adds to customer-related costs by classifying poles, conductors and conduit
19 (FERC accounts 364-367) as 83 percent customer related and transformers (FERC account
20 368) as 64 percent customer related.³

21

² See Charles R. Phillips Jr., *The Regulation of Public Utilities* 438 (1993).

³ Amen Direct at 20

1 **Q. Why is it appropriate to classify distribution system costs as 100 percent demand?**

2 A. There are two main reasons that cost analysts find it reasonable to classify the distribution
3 system as 100 percent demand costs. First, distribution system equipment will not be
4 designed or installed if it is incapable of serving peak demand reliably and safely. This
5 indicates that the cost of distribution equipment is caused by the requirement to meet peak
6 demand. As one analysis of cost of service methods put it: “The theoretical basis for (the
7 basic customer) approach is that the distribution system is sized to a certain capacity, that
8 capacity is available to the total population of customers served by a system, and any
9 capacity used by one customer is generally not available to another.”⁴ That is, from an
10 engineering perspective, the distribution system is designed to meet localized peak demand
11 of a group of customers, and from an economic perspective demand reflects how the system
12 is utilized by customers. Therefore, all distribution costs are more properly classified as
13 100% demand related and not customer related.

14 A second, similar explanation is that demand costs are the fixed costs that the utility
15 incurs to be ready to provide service. According to the late Alfred Kahn, who was a
16 distinguished regulatory economist, demand costs are those caused by “the utility’s
17 readiness to serve, on demand. This readiness to serve is made possible by the installation
18 of *capacity* . . . the fixed, capital costs. . . .And the proper measure of that responsibility is
19 the proportionate share of each customer in the total demand placed on the system at its
20 peak.”⁵ Said another way, it is a customer’s demand that causes the fixed costs of the
21 distribution system, not simply the numerical addition of that customer to the system.

⁴ Jim Lazar, *Cost Elements and Study Organization For Embedded Cost of Service Analysis: Applicable to the Tucson Electric Power Company* 19 (1992).

⁵ Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions* 95 (1988) Vol. I.

1 **Q. Do other regulatory commissions in the United States use the basic customer and**
2 **energy related approaches?**

3 A. Yes. In 2000, the Regulatory Assistance Project (RAP) estimated that approximately 30
4 electric utilities use methods that do not classify any portion of the distribution system as
5 a customer cost,⁶ as opposed to the large percentage MDU is proposing to allocate as a
6 customer cost in this case. I have also testified in a proceeding where a natural gas utility
7 claimed that 19 states utilize the basic customer or peak-and-average approaches.⁷ This
8 demonstrates that many Commissions use these methods to classify and allocate both
9 electric and natural gas distribution systems throughout the country.

10 **Q. Is the basic customer approach commonly used and supported by reliable references?**

11 A. Yes. NARUC has two references that mention the approach.⁸ While the NARUC Electric
12 Manual's discussion of the basic customer approach resides within the marginal cost
13 section of the manual, a similar approach is applied to embedded COSSs throughout the
14 country, as I demonstrate below. In addition, Dr. James Bonbright discusses the basic
15 customer approach in *Principles of Public Utility Rates*.

⁶ See Fredrick Weston, The Regulatory Assistance Project, *Charging for Distribution Utility Services: Issues in Rate Design* at 29 (2000).

⁷ In the Matter of the Application of CenterPoint Energy Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota, Docket No. G-008/GR-15-424, Rebuttal Testimony of Russell A. Feingold, at Schedule 3 (Dec. 18, 2015). Due to the time intensive nature associated with a review of these estimates, I have not verified either of these estimates by assessing each Commission's order on the subject. I believe that it is reasonable to rely on CenterPoint Energy's survey as demonstrative that a minimum of 19 regulatory commissions use the Basic Customer or Peak-and-Average approaches, given that it was provided by a utility in opposition to those methods.

⁸ See: National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* (1992) [hereinafter NARUC Electric Manual]; see also National Association of Regulatory Utility Commissioners, *Gas Distribution Rate Design Manual* (1989) [hereinafter NARUC Gas Manual]. The NARUC Electric Manual methods discusses a method similar to the Basic Customer in the marginal cost section on pages 136–146. The NARUC Gas Manual discusses the Basic Customer approach on page 23.

1 **Q. Have commissions in other states discussed the merits of the basic customer**
2 **approach?**

3 A. Yes. Several states have ruled explicitly that customer charges should reflect only the costs
4 typically associated with the basic customer approach – including states where North
5 Dakota’s electric utilities have a presence. For example, Xcel Energy’s service territory
6 includes Colorado and Texas. In 2018, the Colorado Public Utilities Commission affirmed
7 an Administrative Law Judge’s recommended decision rejecting the zero-intercept method
8 and ordering that FERC accounts 364-368 be classified as 100 percent demand-related.⁹
9 The Texas Public Utilities Commission has stated that “the customer charge shall be
10 comprised of costs that vary by customer such as metering, billing and customer service.”¹⁰
11 It has also found that “[i]t is appropriate to use a 100% demand allocator for distribution
12 accounts 364 through 368,” which is consistent with an application of the Basic Customer
13 approach.¹¹

14 Numerous other states, including those nearby, have reached similar conclusions.
15 For example, Iowa made an approach similar to the basic customer approach the law in
16 that state. Iowa law states that “[c]ustomer cost component estimates or allocations shall
17 include only costs of the distribution system from and including transformers, meters and
18 associated customer service expenses.”¹²

⁹ Colorado Public Utilities Commission. (2018, June 15). Proceeding No. 17AL-0477E, Decision No. C18-0445 in rate case for Black Hills/Colorado Electric Utility Co. https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=25270

¹⁰ Order No. 40, *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344*, at 6 (Nov. 22, 2000) Docket No. 22344 (Public Utility Commission of Texas).

¹¹ Order, *Application of AEP Texas Central Company for Authority to Change Rates*, at 17 (Dec. 13, 2007) Docket No. 33309 (Public Utility Commission of Texas).

¹² Iowa Admin. Code 199-20.10(2)(e).

1 The Idaho Public Utilities Commission moved from the minimum system approach
2 to the basic customer approach in 1998 because it found that the basic customer approach
3 was a superior methodology.¹³

4 The Arkansas Public Service Commission ruled that “accounts 364-368 should be
5 allocated to the customer classes using a 100% demand methodology and...that AEEC
6 [Arkansas Energy Electric Consumers] and HHEG [Hospital and Higher Education Group]
7 do not provide sufficient evidence to warrant a determination that these accounts reflect a
8 customer component necessary for allocation purposes.”¹⁴

9 **Q. Why is it important for the Commission to consider the findings in other states?**

10 A. These examples demonstrate that other jurisdictions clearly recognize the reasonableness
11 and appropriateness of the basic customer approach. Having reviewed these orders, I find
12 their reasoning applicable to this case and persuasive. I recommend that the Commission
13 evaluate MDU’s proposal to increase its monthly fixed customer charge from the
14 perspective of a basic customer approach, not MDU’s minimum system approach.

¹³ Order No. 28097, *In the Matter of the Application of the Washington Water Power Company (Now Avista Corporation dba Avista Utilities—Washington Water Power Division) For an Order Approving Increased Rates and Charges for Electric Service in the State of Idaho*, at 24–27 (July 29, 1999), Case No. WWP-E-98-11 (Idaho Public Utilities Commission).

¹⁴ Order, *In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service*, at 124–26 (Dec. 30, 2013) Docket No. 13-028-U (Arkansas Public Service Commission).

D. MDU's Minimum System Approach

1 **Q. How did MDU estimate the amount of distribution system costs to include in**
2 **embedded customer costs thereby supporting its requested dramatic increase in the**
3 **fixed monthly customer charge?**

4 A. In contrast to the basic customer approach, MDU utilized the minimum system approach.
5 As stated, the minimum system approach is a way to separate the costs of the distribution
6 system into customer related costs and demand related costs. Specifically, MDU utilized
7 an approach known as the minimum size method for FERC accounts 364-367 (poles,
8 conductor, and conduit) and the zero-intercept method for FERC account 368
9 (transformers).

10 **Q. What is the minimum size method?**

11 A. At a high level, the minimum size method creates a minimum system using the average
12 book unit installed cost of the smallest distribution equipment installed and multiplies this
13 unit cost by the total number of distribution equipment on the system. Take poles, towers,
14 and fixtures, for example. The first step of the minimum size method is to determine the
15 average book unit installed cost of the minimum height pole on the distribution system.
16 The second step is to determine how many poles are installed on the distribution system.
17 The third step is to multiply these two numbers together—this number is the cost of the
18 minimum system. Lastly, the cost of the minimum system is compared to the total cost of
19 poles on the distribution system—creating a ratio of customer and demand related pole
20 costs.¹⁵

21 **Q. What is the zero-intercept method?**

¹⁵ The NARUC Electric Manual discusses the minimum size method on pages 90-92.

1 A. At a high level, the zero-intercept method utilizes econometric regression analysis to
2 estimate the “zero or no load” unit cost of each type of distribution system equipment. Take
3 transformers for example. The first general step of the zero-intercept method requires
4 gathering and cleaning cost data. Second, a regression is run on the data. Third, the constant
5 coefficient estimated in the regression is assumed to be the unit cost of a no-load
6 transformer. Lastly and like the minimum size method, the no load transformer cost is
7 multiplied by the total number of transformers to come to the customer related portion of
8 transformer costs.¹⁶

9 It is important to understand that, while methodologically distinct, at their core, the
10 minimum size and zero intercept methods are simply approaches to do the same thing; that
11 is, to estimate the cost of the minimum system. However, because the minimum size
12 method estimates the minimum system using distribution equipment with some load (i.e.
13 because the smallest equipment still serves load) and the zero intercept theoretically
14 estimates a no load scenario, the minimum size method will generally result in a higher,
15 over-estimated percentage of customer costs.

16 **Q. Did MDU justify its decision to base its minimum system study on the minimum size
17 method, rather than the zero-intercept method, for FERC accounts 364-367?**

18 A. No. In Direct, the Company explained why it chose to use the minimum intercept approach
19 for FERC Account 368, but did not explain why it chose the minimum size approach for
20 FERC Accounts 364-367. In discovery, the Company simply stated that “[t]he minimum-
21 sized method is one of two primary acceptable methods for determining the customer
22 component of distribution costs and is consistent with the methodology used by Montana-

¹⁶ The NARUC Electric Manual discusses the zero-intercept method on pages 92-94.

1 Dakota in past electric rate cases filed in North Dakota.”¹⁷ The Company did not explain
2 why this choice was appropriate even though, according to NARUC, “comparative studies
3 between the minimum-size and other methods show that it generally produces a larger
4 customer component than the zero-intercept method.”¹⁸

5 **Q. Do you believe the customer costs estimated using the minimum size and zero-**
6 **intercept analyses reflect the customer-specific cost causation?**

7 A. No. As demonstrated in the subsequent section, I analyzed the Company’s minimum
8 system study and found that it relied on an extremely flawed methodology to classify
9 millions of dollars in distribution system costs. Specifically, the Company contradicted
10 cost causation theory by including primary distribution system components in its minimum
11 system study, neglecting to follow the instructions of the NARUC Electric Manual, and
12 applying an inappropriate and misleading measure of the cost of each minimum-sized
13 component of its distribution system.

14 **Q. Do you have any additional concerns regarding the ability of a minimum system**
15 **approach to accurately reflect cost causation?**

16 A. Yes. In addition to the numerous methodological flaws that I found in MDU’s minimum
17 system study, I also find that the minimum system approach is generally the *least*
18 reasonable way to classify distribution system costs. While the minimum system approach
19 is based on a “certain intuitive appeal,” the method requires the analyst to create a
20 hypothetical, no-capacity system—something that is not real and not directly based on
21 system characteristics. To create this imaginary minimum distribution system, analysts
22 must make *numerous subjective assumptions* that oversimplify system engineering and

¹⁷ MDU response to AARP 1-3d

¹⁸ NARUC Electric Manual at 91

1 assign costs based on questionable cost causative principles. This is different than the basic
2 customer approach, which relies more heavily on actual system data. Since utilities have
3 an economic incentive to over-classify customer costs, the subjective decisions made by
4 utilities can lead to increased customer cost classification. Because of this reliance on
5 actual system data, the basic customer COSS is less subjective.

6 In addition, because demand varies by customer, the collection of demand-related
7 costs from customers should also vary by customer in order to more closely collect costs
8 from the customers who caused them (i.e., cost causation). To do so, costs should be
9 collected through the volumetric charge and not the fixed monthly customer charge. Rate
10 designs with high fixed charges like MDU is pursuing here do not allow for cost collection
11 that reflects cost causation because they collect similar amounts of demand-related costs
12 from each customer within a given rate class tariff, even though different customers incur
13 greater amounts of these costs than others.

14 **Q. Has any credible authority analyzed the different approaches of classifying and**
15 **allocating the distribution system?**

16 A. Yes. I have identified four significant analyses that evaluated the Minimum System
17 approach to some extent. The analyses and controversy associated with the minimum
18 system approach goes back at least to Bonbright's seminal work, *Principles of Public*
19 *Utility Rates*, in 1961. The other analyses were conducted by research consultants or the
20 Regulatory Assistance Project ("RAP").¹⁹

¹⁹ See Fredrick Weston, The Regulatory Assistance Project, *Charging for Distribution Utility Services: Issues in Rate Design* (2000); Jim Lazar, *Cost Elements and Study Organization For Embedded Cost of Service Analysis: Applicable to the Tucson Electric Power Company* (1992); and Jim Lazar and Wilson Gonzalez, *Regulatory Assistance Project, Smart Rate Design For a Smart Future* (2015)

1 **Q. Have North Dakota Public Service Commission staff previously opposed the**
2 **minimum system approach?**

3 A. Yes. As recently as 2021, Commission staff found that “[w]hile [the Minimum Size and
4 Zero Intercept] methods of distribution plant classification were once, but no longer are,
5 widespread among electric distribution utilities, there is, from the perspective of cost
6 causation, no theoretical or practical justification for either method.”²⁰ Commission staff
7 recommended instead that “FERC Accounts 364-368 be classified as wholly demand-
8 related with no customer-related component.”²¹

i. Analysis of MDU’s Minimum System Approach

9 **Q. Did you analyze MDU’s minimum system study methodology and results?**

10 A. Yes. I analyzed MDU’s minimum size study used to classify FERC accounts 364-367
11 (poles, conductor, and conduit) as well as the zero-intercept study to classify FERC account
12 368 (transformers).

13 **Q. Please describe MDU’s minimum size study methodology.**

14 A. The Company’s minimum size study “uses a modeling approach that creates representative
15 one-mile minimum and normal underground and overhead systems, and then calculates the
16 current replacement cost of each.”²² First, the Company modeled hypothetical, one-mile
17 versions of the Company’s overhead and underground distribution systems. Second, the
18 Company identified “the smallest, most commonly used type of pole, conductor, etc;”²³ the

²⁰ See: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota, Docket No. PU-20-441, Direct Testimony of Karl R. Pavlovic at 13 (Apr. 23, 2021), available at <https://psc.nd.gov/database/documents/20-0441/090-010.pdf>

²¹ In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota, Docket No. PU-20-441, Direct Testimony of Karl R. Pavlovic at 15 (Apr. 23, 2021), available at <https://psc.nd.gov/database/documents/20-0441/090-010.pdf>

²² Amen Direct at 18, lines 20-22

²³ Amen Direct at 18, lines 7-8

1 current replacement cost of each including material, labor, equipment, and overhead; and
2 the number of units deemed representative of a one-mile circuit. Third, the unit cost of each
3 type of equipment is multiplied by the total number of units to yield the total cost of a
4 minimum-sized, one-mile circuit.

5 The Company then repeated the above steps to calculate the total cost of a normal
6 (rather than minimum) sized one mile circuit. This process is completed by altering the
7 second step above such that the Company identified the current replacement costs for each
8 type of equipment deemed representative of a “normal” one-mile circuit. Dividing the cost
9 of the minimum-sized one-mile circuit by the cost of the normal one-mile circuit yields the
10 percentage (83 percent) of customer-related costs.

11 **Q. Please describe MDU’s zero-intercept study methodology.**

12 A. The Company conducted a regression analysis for each of three types of transformers on
13 the Company’s system: single-phase and three-phase pad mount transformers, and single-
14 phase line transformers.²⁴ The constant co-efficient in each regression was assumed to
15 represent the unit cost of each zero-load transformer. The Company then multiplied each unit
16 cost figure by the total number of transformers, for each type of transformer, to yield the total
17 replacement cost of all hypothetical, zero-load transformers on the Company’s system.

18 Then, the Company calculated the total cost of all transformers on the Company’s
19 system. Dividing the total cost of hypothetical, zero load transformers by the total cost of
20 all transformers yields the percentage (64 percent) of customer-related costs.

21
²⁴ Amen Direct at 19, lines 18-20

1 **Q. Do you have concerns with MDU’s minimum size and zero-intercept study**
2 **methodologies?**

3 A. Yes. I am concerned by a number of subjective decisions that MDU made in its minimum
4 system study. I will explain each of the following issues in more detail below:

- 5 • MDU’s inclusion of primary distribution system components in the minimum system
6 study contradicts cost causation theory.
- 7 • MDU did not follow the instructions of the NARUC Electric Manual.
- 8 • MDU uses an inappropriate and misleading measure of the cost of each minimum-sized
9 component of its distribution system.

10 **Q. Does MDU classify components of its primary distribution as customer-related?**

11 A. Yes. The Company applied its customer-related cost ratios developed in its minimum size
12 study to the components of FERC Accounts 364-367 associated with both the primary and
13 secondary distribution systems.²⁵

14 **Q. Please explain why classifying the primary distribution system as a customer cost does**
15 **not align with cost causation?**

16 A. The NARUC Manual defines customer costs as those “that are directly related to the
17 number of customers served.”²⁶

18 It is laughable to suggest that the number of customers impacts a 34,000-volt
19 primary distribution line. Primary distribution lines are sized to meet peak load—the
20 number of customers downstream is not an explicit factor. This is because 100 customers
21 or 25,000 customers could require a 34,000-volt line to receive service.

²⁵ MDU Response to AARP 2-8
²⁶ NARUC Electric Manual at 20.

1 Even utilities have found the assumption that high voltage lines are customer-
2 related to be unpalatable. For example, Oklahoma Gas and Electric does not classify
3 primary distribution system costs as customer related within its minimum system study.²⁷

4 Nonetheless, MDU applied its customer-related cost ratio to primary distribution
5 system costs, which is equivalent to claiming that adding individual customers is the root
6 cause behind the costs associated with primary distribution. This is a completely illogical
7 result of MDU's minimum system study.

8 **Q. Did MDU follow the steps described in the NARUC Manual?**

9 A. No. The Company did not follow NARUC's instructions for conducting either the
10 minimum size or the zero-intercept method.

11 To conduct a minimum size study, NARUC instructs analysts to compare the actual
12 value of each plant account with a hypothetical plant account in which each unit of
13 equipment is minimum-sized. There is no mention of the additional step, created by MDU,
14 that models miniature, one-mile versions of the Company's underground and overhead
15 systems. The Company claims that this additional step "attempts to construct a realistic
16 representation of a Montana-Dakota circuit" that is a "realistic proxy for circuits in
17 Montana-Dakota's service territory."²⁸ In order to assess whether the Company's attempts
18 to create representative miniature circuits were successful, I would need to compare the
19 Company's study with results that follow the methodology recommended by NARUC;
20 however, the Company claims that it has not completed a minimum-size study using the
21 methodology recommended by NARUC.²⁹

²⁷ See CAUSE NO. PUD 201700496

²⁸ Amen Direct at 19, lines 5-6 and 9-10

²⁹ MDU Response to AARP 1-3

1 To conduct a zero-intercept study on transformers, NARUC instructs that “[o]nly
2 single-phase sizes up to and including 50 kVA should be used in developing the customer
3 components.”³⁰ However, the Company also developed a zero-intercept cost for much
4 more expensive, three-phase padmount transformers of up to 2500 kVA, and included these
5 more expensive transformers in its calculation of customer costs.

6 **Q. What are the consequences of the Company’s deviation from the steps outlined in the**
7 **NARUC manual?**

8 A. It is worth highlighting that the NARUC Electric Manual’s methodology is meant to
9 represent cost causation. Not following the methodology, therefore, will result in estimates
10 that do not reflect cost causation, as theorized by the NARUC Electric Manual.

11 As stated, it is not possible to evaluate whether the Company’s attempts to model
12 representative, miniature distribution systems were successful because the Company has
13 not conducted the study as recommended by NARUC. I am concerned, however, that
14 including this additional step provides unnecessary opportunities for error. In addition, I
15 am concerned that the Company did not justify the assumptions that it used to construct its
16 “representative” one-mile system, such as the quantity of each size of pole and
17 percentage/length of each type of conductor and cable used. When asked for justification,
18 the Company responded that “[t]here are no additional Excel spreadsheets supporting” the
19 calculations.³¹

20 In addition, when conducting its zero-intercept study on transformers, the
21 Company’s decision to include in its calculation of customer costs transformers that exceed
22 NARUC specifications inflates customer-related costs. This is because the zero-intercept

³⁰ NARUC Electric Manual at 94

³¹ MDU Response to AARP 2.2

1 cost for three phase transformers is substantially higher than that of their single-phase
2 counterparts.

3 The Company has not cited any authoritative literature that would justify why its
4 departure from the NARUC Electric Manual is appropriate.

5 **Q. Are there additional ways in which MDU did not follow the steps outlined in the**
6 **NARUC Manual?**

7 A. Yes. NARUC instructs that, when conducting a minimum size study, “normally, the
8 average book cost for each piece of [minimum size] equipment determines the price of all
9 installed units.”³² Similarly, when conducting a zero-intercept study, NARUC instructs that
10 the average installed book cost per transformer should be used.³³ In contrast, MDU’s
11 minimum size study is based on “current replacement cost[s],”³⁴ including “actual material,
12 labor, equipment, and overhead costs from the first quarter of 2022.”³⁵ The zero-intercept
13 study is based on “the actual cost of transformers purchased based on current purchasing
14 agreements.”³⁶ In other words, MDU chooses to apply the current costs for new equipment
15 to calculate the costs of all of its existing minimum- and normal-sized infrastructure in a
16 particular account, even though the units in those accounts have been installed over the
17 past century.

18
19
20

³² NARUC Electric Manual at 90-91

³³ NARUC Electric Manual at 94

³⁴ Amen Direct at 18, line 22

³⁵ MDU Response to AARP 1.3c

³⁶ Response to AARP 1.4d

1 **Q. What is your concern with the Company's subjective decision?**

2 A. Any of the individual cost drivers – if not all of them – could have changed over the decades
3 that each distribution component has been installed and in service. Applying a present cost
4 to old infrastructure inevitably obscures the true cost of that infrastructure.

5 **Q. What costs are commonly used by utilities?**

6 A. Utilities do not adhere to any objective approach—which is the point. As stated, the
7 NARUC manual specifies that average installed book cost be used.

8 **Q. Is MDU's minimum system study reliable as a method of classifying distribution
9 system costs?**

10 A. No. Not only is the minimum system method a theoretically unsatisfactory approach – as I
11 argue at length in earlier sections – but MDU's minimum system study is particularly
12 unacceptable for the reasons I described previously.

13 **Q. What process do you recommend the Commission use for classifying distribution
14 system costs?**

15 A. I recommend that the Commission use the basic customer approach to classify distribution
16 system costs. Furthermore, I recommend that the results of the COSS using the basic
17 customer approach be used to inform rate design and revenue apportionment. This
18 approach will provide an appropriate and sound fixed monthly customer charge that
19 reflects cost causation as I describe above.

III. REVENUE APPORTIONMENT

20 **Q. What is the purpose of this section of your testimony?**

21 A. In this section, I make recommendations regarding the Company's approach to revenue
22 apportionment and present the impact of my proposal on each rate class.

1 **Q. How does the Company propose to apportion revenues between classes?**

2 A. According to the approach to revenue apportionment selected by the Company:

3 *[The selected] option was to limit the increase to customer classes above*
4 *parity to receiving a revenue increase equal to 1/3 of the system average*
5 *increase, or 4.634%, and cap the maximum increase to any class at 35%,*
6 *with the balance of the increase going to the Residential class. Classes*
7 *where an increase between 4.634% and 35% would bring them to parity*
8 *were brought to parity. This option would mitigate the divergence from*
9 *parity for those classes above parity, while making reasonable movement*
10 *towards parity for the other classes.³⁷*

11 **Q. Do you have any recommendations related to revenue apportionment?**

12 A. Yes. I recommend that:

- 13 • Revenue apportionment be informed by results of the COSS using the basic
- 14 customer approach, as described in Section II.
- 15 • The maximum increase to any class should be capped at 20%.
- 16 • The increase to customer classes above parity should be limited to 90% of the
- 17 system average, or 12.5%.

18 **Q. Why do you recommend that the maximum increase to any class be capped at 20%?**

19 A. A 35% maximum increase as proposed by the Company is quite substantial and would
20 create rate shock. A 20% rate increase better balances the need avoid rate shock with the
21 need to bring classes closer to parity.

22 **Q. Why do you recommend an increase to the Company's proposed limit to customer**
23 **classes above parity?**

24 A. When the power system is experiencing significant rate pressure from not only
25 infrastructure investment but fuel costs, all customers should share in an equitable portion

³⁷ Amen Direct at 31-32, lines 23-4

1 of these costs as the system is shared by all customers. Increasing the limit for customers
 2 above parity balances the need to mitigate rate shock for those substantially below parity.

3 **Q. Have you analyzed how your proposed changes to revenue apportionment would**
 4 **impact class revenues?**

5 A. Yes. Table 1 below compares the class revenue increases and parity ratios under my
 6 apportionment proposal with those under the Company’s proposal.

7 **Table 1: Impact of Proposed Revenue Apportionment on Class Revenues**

Rate Schedule	% Revenue Increase			Parity Ratio	
	MDU	AARP	Difference	MDU	AARP
Residential Rate 10	21.05%	13.49%	-7.56%	0.88	0.94
Small General Rate 20	21.44%	12.52%	-8.91%	1.00	1.13
Irrigation Rate 25	35.00%	20.00%	-15.00%	0.46	0.26
LG Primary Rate 30	13.24%	20.00%	6.76%	1.00	0.85
LG Secondary Rate 30	4.63%	12.52%	7.89%	1.22	1.16
TOD LG Primary Rate 31	4.63%	18.17%	13.53%	1.01	1.00
TOD LG Secondary Rate 31	4.63%	12.52%	7.89%	1.28	1.18
Space Heating Rate 32	14.45%	20.00%	5.55%	1.00	0.77
Sm Municipal Rate 40	35.00%	20.00%	-15.00%	0.86	0.79
Mun Lighting Pri Rate 41	10.92%	10.92%	-	1.58	1.41
Mun Lighting Sec Rate 41	9.76%	9.76%	-	1.54	1.53
Mun Pumping Pri Rate 48	35.00%	20.00%	-15.00%	0.98	0.70
Mun Pumping Sec Rate 48	4.63%	12.52%	7.89%	1.07	1.09
Outdoor Lighting Rate 52	4.63%	20.00%	15.37%	1.06	0.98
IT Demand Response Rate 38	4.63%	12.52%	7.89%	1.31	1.03
Contract - Tesoro	13.24%	20.00%	6.76%	0.88	0.80
Contract - Sabin	13.24%	20.00%	6.76%	0.76	0.64
Total North Dakota System	13.92%				

8
 9 My proposal does not impact the Company’s revenues under current rates; rather it
 10 impacts each rate class’s share of the Company’s revenue requirement. This in turn affects
 11 the revenue increase needed to bring each rate class to parity.

12 **Q. Do you have any observations regarding the impact of your proposal on class**
 13 **revenues?**

1 A. Yes. My proposal would result in a smaller revenue increase for residential, small
2 commercial, irrigation, small municipal, and municipal pumping (primary service)
3 customers while simultaneously bringing the residential class closer to parity, as a smaller
4 share of the residential revenue requirement would be allocated to residential customers
5 under my proposal. My proposal would result in a larger revenue increase for large C&I
6 customers on Rates 30-31, including contract customers associated with these schedules,
7 as well as for Space Heating, Municipal Pumping (Secondary Service), Outdoor Lighting,
8 and IT Demand Response customers. Most importantly, my recommendation is based off
9 only changing one method within the COSS. If one were to vary other subjective
10 assumptions within the COSS, it could very likely show additional costs shifts out of the
11 residential class. My proposal strikes a reasonable balance in this way.

IV. RATE DESIGN

12 **Q. What is MDU recommending in this case for its residential customer charge?**

13 A. Relying on its flawed minimum system approach, MDU is proposing to increase the fixed
14 basic service charge for Residential Rate 10 customers from \$0.46/day to \$0.67/day, or by
15 46 percent. This translates to a monthly increase from \$13.99 to \$20.38, or \$6.39/month.³⁸

16 **Q. Do you agree with MDU's proposal to increase its fixed monthly residential customer
17 charge by 46 percent?**

18 A. No. I do not agree with MDU's customer charge increase for multiple reasons.

19 • First, MDU's justification for the magnitude of its customer charge is directly
20 related to the results of its minimum system study, which is highly flawed as I

³⁸ Amen Direct at 35

1 describe in Section II of my testimony. As such, from a technical standpoint,
2 MDU's recommendation does not align with cost causation.

3 • Second, high customer charges harm customers, including low-usage and low-
4 income customers as well as those investing in energy efficiency.

5 • Finally, the Company's justification for its proposed customer charge increase
6 lacks theoretical and analytical support.

7 These concerns have become increasingly important given the evolving power mix in the
8 MISO region, including North Dakota, which in contrast to MDU's proposal to increase
9 fixed charges, will require a greater emphasis placed on volumetric charges to reflect the
10 temporal value of energy and demand.

11 **Q. How is the power grid evolving?**

12 A. The penetration of variable renewable energy in MISO has increased dramatically in recent
13 years, and this trend is expected to continue. In 2016, wind comprised 8 percent of annual
14 generation in MISO and 27 percent of annual generation in MISO North, which includes
15 North Dakota.³⁹ For the ISO as a whole, wind and solar could approach 30 percent of
16 annual generation within 5 years and 60 percent by 2041.⁴⁰ The increase in variable
17 resources on MISO's system makes the timing of grid services and the availability of grid
18 flexibility increasingly important, as demonstrated by recent experiences. In the April 2022
19 Planning Resource Auction for Planning Year 2022-2023, capacity prices in MISO's
20 Northern and Central region increased to \$236.66/MW-day (the Cost of New Entry), as

³⁹ See: Jordan Bakke, David Duebner, Durgesh Manjure, Laura Rauch, Evolution of the Grid in MISO Region, MIPSYCON (November 7, 2017) at 6. [https://ccaps.umn.edu/documents/CPE-Conferences/MIPSYCON-PowerPoints/2017/GenTheEvolutionoftheGridintheMidcontinentIndependentSystemOperator\(MISO\)Region.pdf](https://ccaps.umn.edu/documents/CPE-Conferences/MIPSYCON-PowerPoints/2017/GenTheEvolutionoftheGridintheMidcontinentIndependentSystemOperator(MISO)Region.pdf)

⁴⁰ 2022 Regional Resource Assessment, MISO (November 2022) at 5.

<https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf>

1 compared to \$5/MW-day the prior year. This dramatic jump in prices is thought to be
2 attributable to the decrease in accredited capacity as coal plants were replaced by variable
3 solar and wind, as well as the increase in electricity demand as the region recovers from
4 COVID-19.⁴¹ Meanwhile, MISO has placed a higher priority on seasonal differentiation as
5 FERC recently approved MISO's shift towards establishing four seasonal capacity auctions
6 with separate reserve margins and accreditation of resources based on a generating unit's
7 seasonal performance during tight system conditions. FERC stated that these changes
8 would "better align resource adequacy requirements with periods of increased risks on the
9 MISO system," provide "a more granular assessment of seasonal resource adequacy needs"
10 and ensure that load serving entities ("LSEs") avoid procuring "capacity beyond what is
11 necessary to ensure resource adequacy in a given Season."⁴² Each of these examples are a
12 clear indication that load flexibility is more valuable than once thought.

13 **Q. How are these changes on the power grid relevant to rate design?**

14 A. As increasing renewable penetration amplifies the temporal value of grid services and
15 flexibility, greater emphasis will need to be placed on time-varying volumetric cost
16 recovery to incentivize load flexibility. Modern COSS and rate design need to adapt to
17 reflect this changing value by creating and improving temporal cost allocations. Temporal
18 cost allocation acknowledges that, with high levels of renewable energy on the grid, load
19 profiles are more important than load factors. This is demonstrated through the growing
20 issue of addressing peaks and low-load conditions during shoulder months as opposed to
21 the traditional focus of meeting peak in summer months in grids with high renewables.

⁴¹ Ethan Howland, "Capacity prices jump across MISO's central and northern regions, driven by supply shortfall," *Utility Dive* (April 18, 2022). www.utilitydive.com/news/capacity-prices-auction-miso-midcontinent/622186

⁴² Order, FERC Docket No. ER22-495-000, Aug. 31, 2022

1 This growing need to recognize the timing of peaks elevates the importance of
2 appropriately allocating costs that vary with demand as being demand related. Doing so
3 may increase time-varying volumetric cost recovery and be more efficient and equitable as
4 flexibility is appropriately incentivized for its increasing value to the grid.

5 **Q. Please provide another example of how traditional cost causation has changed due to**
6 **technological advances.**

7 A. Investment in advanced metering infrastructure (“AMI”) serves as an illustrative example.
8 Traditional analog meters simply recorded customer consumption, serving only the individual
9 customer using the meter, and therefore were classified as a customer costs. AMI, however,
10 enables information transfer and action to reduce line losses and lower peak demand, in turn
11 yielding generation, transmission, and distribution system benefits. There is an emerging
12 argument that customers across those system levels should pay for these services, rather than
13 only the customer who hosts the meter. This is a dramatic departure from the traditionally
14 understood cost responsibility for meters.

15 I offer no comment on whether MDU should change its approach to how AMI costs
16 are classified at this time. I raise this issue as an additional example of how traditional
17 interpretation of the cost causation principle may need to evolve with grid conditions and
18 technological advances in order to ensure equitable cost functionalization, classification, and
19 allocation. In this example, traditional cost causation would indicate that the customer who
20 needs a meter incurs the meter cost and therefore should pay for all of it. However, the principle
21 of “beneficiary pays” better accommodates the nuances of AMI benefits and costs. This
22 principal supplements cost causation by recognizing that those who benefit from the cost are
23 not always those who cause it and suggests that costs should be assigned to all beneficiaries.
24 Although I am not commenting on MDU’s approach to classifying and allocating AMI costs,

1 I believe that these examples indicate the point I wish to make: COSS and rate design must
2 evolve with the electric grid. As stated, today's grid conditions support temporal cost allocation
3 and volumetric cost recovery, in contrast to MDU's proposed fixed monthly customer charge
4 increase. If AMI were treated in a modern fashion as described above, this would result in an
5 even lower fixed charge than MDU has in place today.

6
A. MDU's minimum system study is not a valid justification to increase customer charges and would result in charges that do not align with cost causation

7 **Q. Is the Company's minimum system study a valid justification for increasing the**
8 **customer charge?**

9 A. No. As described in Section III, the Company's minimum system study suffers from both
10 theoretical and computational flaws that fail to reflect cost causation and make the study an
11 unreliable basis for informing rates. I recommend using the less subjective Basic Customer
12 Approach to inform rates.

13 **Q. Have you analyzed how the customer-related costs would change under a basic**
14 **customer COSS compared to how MDU calculated it using its minimum system**
15 **approach?**

16 A. Yes. If the Basic Customer Approach were used, the Company's monthly basic charge for
17 residential customers would be only \$8.97/month or \$0.295/day, which is less than the
18 Company's current customer charge of \$13.99/month. Thus, the Company's proposal to
19 increase the basic customer charge is not justified.

B. High customer charges harm customers, including low-usage and low-income customers as well as those investing in energy efficiency

1 **Q. Do customers prefer high customer charges?**

2 A. No. I am not aware of consumer advocates promoting higher fixed charges; rather, many
3 consumer advocates oppose increases in the fixed charge, such as the National Association
4 of State Utility Advocates (“NASUCA”) and National Consumer Law Center.⁴³ I have
5 attached the NASUCA Customer Charge Resolution as Exhibit AARP-REN-2. In
6 addition, numerous Commissions have recently rejected proposals to increase fixed
7 charges.⁴⁴

8 **Q. Do other states where North Dakota’s electric utilities have a presence have lower
9 customer charges?**

10 A. Yes. In fact, MDU and Xcel’s customer charges for standard residential service are lower
11 than MDU North Dakota’s current \$13.99/month charge in every other state in their service
12 territory with the exception of Wyoming and Wisconsin. MDU’s customer charge in
13 Montana is only \$0.19/day (about \$5.80/month)⁴⁵ and in South Dakota it is only \$0.247/day
14 (about \$7.50/month).⁴⁶ Xcel’s monthly customer charge is only \$8 in Minnesota,⁴⁷ \$5.60

⁴³ See: <https://www.nclc.org/issues/energy-utilities-a-communications/utility-rate-design.html>.

⁴⁴ According to a 2017 report, “Forty-four utility requests to increase residential fixed charges were decided in 2017, with 86 percent receiving either a portion of the requested increase or no increase at all. Only six utilities were granted their full requested increases. Of those utilities receiving a partial increase, the average was 26 percent of the utility’s original request.” A summary of the report is available here: <https://nccleantech.ncsu.edu/2018/01/24/the-50-states-of-solar-report-2017-annual-review-q4-update-edition-now-available/>.

⁴⁵ See: <https://www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Tariffs/Montana/Electric/MTElectric10.pdf>

⁴⁶ See: <https://www.montana-dakota.com/wp-content/uploads/PDFs/Rates-Tariffs/SouthDakota/Electric/SDElectric10.pdf>

⁴⁷ See: <https://mn.my.xcelenergy.com/s/billing-payment/residential-rates/residential-plan>

1 in Colorado;⁴⁸ \$9 in Michigan;⁴⁹ \$9.80 in New Mexico;⁵⁰ \$8.25 in South Dakota (\$10.25
2 if underground)⁵¹, and \$11.40 in Texas.⁵²

3 **Q. How do high fixed monthly charges effect equity within the residential rate class?**

4 A. When compared to a rate design that collects most or all demand-related costs through a
5 volumetric rate, high customer charges shift cost collection to lower usage customers. The
6 information submitted by the Company confirms my concern: according to the Company's
7 response to AARP 1-10, the higher the percent increase to a customer's bill, the lower the
8 customer's average monthly usage. For example, according to the Company, customers
9 who would experience a 10-15 percent bill increase use 1,950.4 kWh per month on average,
10 while customers who would experience a 25-30 percent bill increase use only 165.5 kWh
11 per month on average.⁵³ Usage is often correlated with income, meaning that all else equal,
12 lower income residents often consume less than higher income residents. When this is true,
13 high fixed charges shift costs onto lower income residential customers.

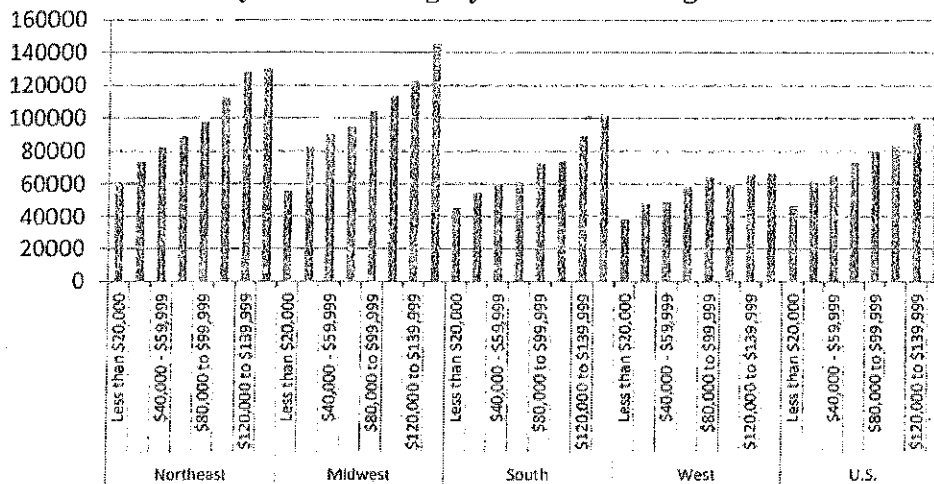
14 **Q. Is there evidence that low income customers tend to use less electricity than high
15 income customers?**

16 A. Yes. Every several years, the Energy Information Administration (EIA) conducts the
17 Residential Energy Consumption Survey (RECS) which collects information on energy

⁴⁸ See: https://www.xcelenergy.com/staticfiles/xeresponsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/PSCo_Electric_Entire_Tariff.pdf
⁴⁹ See: <https://www.xcelenergy.com/staticfiles/xeresponsive/Company/Rates%20&%20Regulations/MI-Res-Rate-Card.pdf>
⁵⁰ See: [https://www.xcelenergy.com/staticfiles/xeresponsive/Company/Rates%20&%20Regulations/Rate%201,%20Rev.%2015%20-%20Residential%20Service%20\(2-26-22\).pdf](https://www.xcelenergy.com/staticfiles/xeresponsive/Company/Rates%20&%20Regulations/Rate%201,%20Rev.%2015%20-%20Residential%20Service%20(2-26-22).pdf)
⁵¹ See: https://www.xcelenergy.com/staticfiles/xeresponsive/Company/Rates%20&%20Regulations/Se_Section_5.pdf
⁵² See: [https://www.xcelenergy.com/staticfiles/xeresponsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/IV-3,%20Rev%2022%20-%20Residential%20Service%20\(3-1-22\).pdf](https://www.xcelenergy.com/staticfiles/xeresponsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/IV-3,%20Rev%2022%20-%20Residential%20Service%20(3-1-22).pdf)
⁵³ MDU Response to AARP 1-10 (Attachment A)

1 characteristics, usage patterns, and household demographics from a nationally
 2 representative sample of households across the country. The EIA has not yet released the
 3 billing data on energy consumption and expenditures for the most recent, 2020 iteration of
 4 the RECS survey. The 2015 RECS survey, however, which is the most recently completed
 5 version prior to 2020, shows a clear and consistent correlation between income and energy
 6 usage across each census region of the country as indicated by Figure 1 below.

7 **Figure 1: Median 2015 Household Energy Usage (thousand Btu)**
 8 **by Income Category and Census Region⁵⁴**



9
 10 **Q. Do you have any other observations regarding the correlation between income and**
 11 **energy usage?**

12 **A.** Yes. In my experience, utilities often attempt to argue that low-income customers are not
 13 necessarily low-usage by focusing on the small subset of low-income customers who
 14 receive LIHEAP assistance. Although I understand that the subset of low-income
 15 customers receiving LIHEAP assistance may be the only proxy for income available to the

⁵⁴ National Consumer Law Center Analysis of U.S. EIA 2015 Residential Energy Consumption Survey Data. In: John Howat, John T. Colgan, Wendy Gerlitz, Melanie Santiago-Mosier, and Karl R. Rábago, "Reversing Energy System Inequity: Urgency and Opportunity During the Clean Energy Transition," p. 2. <https://www.nclc.org/wp-content/uploads/2022/08/report-reversing-energy-system-inequity.pdf>

1 Company, it is not an appropriate sample to draw conclusions about energy usage among
2 low-income customers as a whole. First, usage patterns among LIHEAP recipients are
3 unlikely to be reflective of low-income customers as a whole (including those not receiving
4 assistance) because receiving subsidies for electricity would tend to encourage electricity
5 consumption. Second, only 14% of North Dakota’s eligible population is on LIHEAP.⁵⁵
6 Thus, focusing on the small subset of customers who receive assistance is not an
7 appropriate justification for a proposal that would disproportionately harm low-income
8 customers not receiving assistance.

9 **Q. Why is it important to consider the impact on low-income people when designing**
10 **rates?**

11 A. Low-income people have higher “energy burdens,” meaning that they spend a
12 disproportionate amount of their income on energy bills. In North Dakota, the average
13 energy burden across all income levels was 3 percent in 2018, but 23 percent – nearly 8
14 times higher – for households below the federal poverty level. For households earning
15 between 100 and 150 percent of the federal poverty level, the average energy burden was
16 10 percent.⁵⁶ As of 2021, 15 percent of the population in North Dakota lived below 150
17 percent of the federal poverty level.⁵⁷ The Company’s proposal would disproportionately
18 increase energy bills for the customers who are already spending a disproportionate share
19 of their income on energy, further limiting the resources that such customers have to spend
20 on food, housing, health expenses, and other essentials.

⁵⁵ National Energy & Utility Affordability Coalition, “North Dakota By the Numbers.” <https://neuac.org/wp-content/uploads/2021/02/North-Dakota-State-Sheet-2022.pdf>

⁵⁶ U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool (last visited January 11, 2023), <https://www.energy.gov/eere/slsc/maps/lead-tool>

⁵⁷ <https://www.census.gov/data/tables/time-series/demo/income-poverty/cps-pov/pov-11.html#150175>

1 **Q. Would increasing fixed charges harm other customer groups?**

2 A. Yes. Because fixed charge increases are offset by corresponding decreases in volumetric
3 energy rates, increasing fixed charges increases the payback period of investment in energy
4 efficiency upgrades. This decreases the economic incentive and harms customers who have
5 already chosen to invest in more efficient technologies.

6 **Q. Does the Company recognize that increasing fixed charges decreases the incentive to**
7 **conserve energy?**

8 A. No. The Company claims, incorrectly and without evidence, that increasing the fixed
9 charge “does not provide a disincentive to use energy wisely” as “[c]ustomers' conservation
10 efforts are rewarded through lower bills because of lower energy consumption.”⁵⁸ This
11 ignores the reality that, as mentioned in the previous question, increasing fixed charges and
12 correspondingly decreasing volumetric charges provides a smaller incentive to conserve
13 energy than would be possible with higher volumetric rates and lower fixed charges.
14 Increasing customer charges can undo the progress of customers' efforts to conserve
15 energy by decreasing the control that customers have over their energy bills, thus reducing
16 their incentive to conserve and invest in efficiency upgrades or distributed technologies.

17 **Q. Will MDU have the opportunity to recover its revenue requirement if the proposed**
18 **customer charge increase is rejected?**

19 A. Yes. Rates are designed to recover MDU's revenue requirement in a rate case. If the
20 Commission rejects the proposed increase in the fixed monthly customer charge, then an
21 offsetting amount is collected through the volumetric rate and can then be collected from

⁵⁸ Amen Direct at 37, lines 13-15

1 customers based on how much electricity the specific customer consumes. Moving cost
2 recovery from fixed charges into volumetric charges will be revenue neutral to MDU.

C. The Company's justification for its proposed customer charge increase lacks theoretical and analytical support.

3 **Q. How does MDU justify its proposed residential customer charge increase?**

4 A. According to MDU, the Company's proposal to increase its fixed customer charge will:

- 5 • Send appropriate economic price signals;
- 6 • Minimize intra-class subsidies by recovering fixed costs through fixed charges;
- 7 • Contribute to bill stability for customers, including by mitigating the impact of
8 abnormal weather on customers' bills;
- 9 • Contribute to revenue stability for the Company, including by mitigating the impact
10 of abnormal weather;
- 11 • Better align revenues with the investment made to serve each customer.⁵⁹

12 **Q. Let's consider each of these claims in turn. Has the Company demonstrated that its
13 proposal would send appropriate economic price signals?**

14 A. No. Appropriate or efficient economic price signals are based on marginal cost. In contrast,
15 the Company's calculation of customer costs is based on historic or embedded costs from
16 its COSS. This is completely different than marginal costs, and includes several costs –
17 such as the cost of transformers and secondary distribution system – that would not be
18 appropriate in a marginal cost study. Because efficient price signals are based on marginal
19 cost and the Company's customer charge is based on embedded costs, the Company's
20 proposed customer charge increase would not send efficient economic price signals.

⁵⁹ Amen Direct at 37-38

1 **Q. Has the Company demonstrated that its proposal would minimize intraclass subsidies**
2 **by recovering fixed costs through fixed charges?**

3 A. No. The costs that the Company considers “fixed” do not fit its own definition of fixed
4 costs. According to the Company, “fixed costs include all costs that do not vary with the
5 amount of energy consumed by customers.”⁶⁰ As previously stated, however, costs in
6 FERC Accounts 364-368 vary with demand (peak energy consumed), and thus do not align
7 with the Company’s own definition of fixed costs. By assuming that costs are fixed and
8 therefore need to be recovered through a fixed charge, the Company is implicitly assuming
9 that once installed, equipment will not need to be replaced due to capacity overload. This
10 assumption is unsupported and untrue for some of the equipment deemed fixed, such as
11 transformers.

12 Because MDU’s proposal would decrease a customer’s control over their energy bill,
13 the intra-class subsidy would be exacerbated – particularly harming low-usage customers.

14 In addition, the power system is evolving such that the Company’s claim is out-of-
15 date. As stated in Section II, as the value of time-variant grid services and flexibility
16 increases, demand-related costs are more efficiently collected through time-variant rates to
17 send better price signals to customers and therefore encourage consumption that reflects
18 the true conditions on the electric grid.

19 **Q. Has the Company demonstrated that its proposal would contribute to bill stability for**
20 **customers and revenue stability for the Company, including by mitigating the impact**
21 **of abnormal weather?**

⁶⁰ Amen Direct at 14, lines 3-4

1 A. The Company’s argument appears to be misplaced. Customers desiring greater bill stability
2 already have option to enroll in Balanced Billing. According to the Company, 12 percent
3 of residential customers have participated in this program in recent years.⁶¹ This option is
4 likely to be far more effective in stabilizing customer bills than MDU’s proposal to increase
5 fixed charges.

6 Although increasing fixed charges would stabilize revenues for the Company, this
7 is a Company preference because it lowers risk. It is not a rate design principle and should
8 not be explicitly considered when designing rates.

9 **Q. Has the Company demonstrated that its proposal would better align revenues with**
10 **the investment made to serve each customer?**

11 A. No. The Company’s claim appears to be based on its classification of expenses in FERC
12 Accounts 364-368 as customer-related. As demonstrated in Section II, however, this
13 classification is based on a minimum system approach that suffers from substantial
14 theoretical and computational flaws.

15 **Q. What is your recommendation for the Commission regarding the MDU’s proposed**
16 **residential fixed monthly customer charge?**

17 A. I recommend that the Commission reject the Company’s proposal to significantly increase
18 the customer charge, and maintain the current customer charge for residential customers.

19
20

⁶¹ MDU Response to AARP 1-7 (Attachment)

V. SUMMARY OF RECOMMENDATIONS

1 **Q. Could you please provide a summary of your recommendations for the Commission?**

2 **A.** Yes. I recommend that:

- 3 • the Commission apply the basic customer approach as the basis for informing rate design
- 4 and revenue apportionment;
- 5 • the Company's approach to revenue apportionment should also:
 - 6 ○ cap increases to the revenue requirement at 20% for any class; and
 - 7 ○ limit increases to classes above parity to 90% of the system average increase;
- 8 • the Commission reject MDU's proposal to dramatically increase its residential basic
- 9 customer charge.

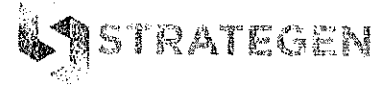
VI. CONCLUSION

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

11 **A.** Yes.

Ron Nelson

Senior Director



Ron is a Senior Director at Strategen and a subject matter expert in gas and electric Advanced Rate Design, Cost of Service Studies, and Decarbonization. Ron leads a team that provides expertise and expert testimony on numerous topics, including multi-year utility rate plans, performance incentive mechanisms, cost of service modeling, line extension policies, residential and commercial rate design, renewable energy program design, system planning, DER interconnection cost allocation and recovery, and DER integration.

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Education

MS

Agricultural and Resource
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Colorado State University
2013

BA

Environmental Economics

Western Washington University
2011

Work Experience

Senior Director

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- + Subject matter and testimony expert in advanced rate design, embedded and marginal cost of service modeling, performance-based regulation, gas decarbonization, and DER integration and compensation.
- + Designing and implementing policies and programs to decarbonize energy systems including deployment of distributed energy resources, demand-side management programs, energy storage and grid integration.
- + Expert witness and advisor that has testified across 12 states in over 50 proceedings and supported multiple state commissions in various proceedings

Economist

Minnesota Attorney General's Office / St. Paul, MN / 2013 - 2017

- + Provided expert testimony on cost of service modeling, rate design, grid modernization and utility business models.
- + Analyzing issues related to conservation incentive programs, value of solar, grid modernization, performance-based regulation, renewable energy program design, and MISO.
- + Reviewed and made recommendation to improve gas company pipeline replacement programs, demand response tariffs, performance metrics, and rate designs.

Graduate Research Associate

Colorado State University / Fort Collins, CO / 2011 - 2013

Economic Research Assistant

Washington State University / Mount Vernon, WA / 2009 - 2011

Ron Nelson
Senior Director



Domain Expertise

Regulatory Strategy

Gas Decarbonization

Rate Design

Performance-Based Regulation

Performance Incentive
Mechanisms

Cost of Service Analysis

DER Compensation

Rate Case Support

Electric Vehicles

Renewable Energy Program
Design

Expert Testimony

Central Maine Power Company: Request for Approval of Distribution Rate Increase and Rate Design Changes Pursuant to 35-A M.R.S. Section 307, Docket 2022-00152, On Behalf of the Governor's Energy Office w/Panelists Caroline Palmer and Nikhil Balakumar
Marginal Cost of Service, Performance-Based Regulation, Distribution System Planning
Direct

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota (Docket No 21-630), On Behalf of the Citizen's Utility Board of Minnesota
Rate Riders, Fuel Clause Risk Sharing, and MYRP Structure
Direct | Rebuttal

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota (Docket No 21-630), On Behalf of the Clean Energy Organizations
Advanced Rate Design, Regulatory Sandbox, TOU Rate Design
Direct | Surrebuttal

Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid, Capital Investment Project Filing: Shutesbury (D.P.U. 22-61) On Behalf of the MA AGO w/ Panelists Jorge Camacho and Eli Asher
DER Integration, Interconnection and Cost Allocation
Direct

In the Matter of Delmarva Power and Light Company's Application for an Electric Multi-Year Plan (Case No. 9681) On Behalf of the Office of People's Counsel w/ Panelist Jorge Camacho
Distribution System Planning, Capital Investment Plan, Multi-Year Rate Plan Structure, Revenue Decoupling
Direct (No. 21) | Rebuttal (No. 23)

Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of the Company's Marion-Fairhaven capital project proposal under the Provisional Program established by the Department in Provisional System Planning Program, D.P.U 20-75-B (2021) (D.P.U. 22-47) On Behalf of the MA AGO w/ Panelists Jorge Camacho, Eli Asher, and Fred Schaefer
DER Integration, Interconnection and Cost Allocation
Direct | Surrebuttal

Expert Testimony (Continued)

Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX. (Docket No. 22-0432 and 22-0442) On Behalf of NRDC, Sierra Club, EDF, RHA and Little Village Environmental Justice Organization (LVEJO)

Electric Vehicle Rate Design and Energy Management Systems

Petition for Approval of Beneficial Electrification Plan pursuant to Section 45 of the Electric Vehicle Act (Docket No. 22-0431 and 22-0443) On Behalf of NRDC, Sierra Club, EDF, and RHA

Electric Vehicle Rate Design and Energy Management Systems

In the Matter of the Application of Oklahoma Gas & Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma

Cost of service, rate design, formula rate plan

Direct | Stipulation

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota. Docket No. E-015/GR-21-335. On Behalf of CUB Minnesota

Cost recovery, cost of service, and revenue apportionment

Direct | Surrebuttal

Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act, Commonwealth Edison Company, Docket No. 22-0067 On Behalf of NRDC

Demand Response and Electric Vehicle Performance metrics

Direct | Rebuttal

Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act, Ameren Illinois Company, Docket No. 22-0063 On Behalf of NRDC

Demand Response and Electric Vehicle Performance metrics

Direct | Rebuttal

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief. U-21148. On Behalf of NRDC

Performance-based regulation and gas decarbonization

Direct

In the Matter of Delmarva Power & Light Company's Application for an Electric Multi-Year Plan, Case No. 9681

Revenue Decoupling, Multi-Year Rate Plan, Capital Investment Plan

Expert Testimony (Continued)

Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of the Company's Marion-Fairhaven capital project proposal under the Provisional Program established by the Department in Provisional System Planning Program, D.P.U 20-75-B (2021)

DER integration, flexible interconnection, Capital Investment Project
[Direct](#) | [Surrebuttal](#)

In the Matter of the Application of Oklahoma Gas & Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma

Cost of service, rate design, formula rate plan
[Direct](#) | [Stipulation](#)

In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota, Docket No. E-015/GR-21-335, On Behalf of CUB Minnesota

Cost recovery, cost of service, and revenue apportionment
[Direct](#) | [Surrebuttal](#)

Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act, Commonwealth Edison Company, Docket No. 22-0067 On Behalf of NRDC

Demand Response and Electric Vehicle Performance metrics
[Direct](#) | [Rebuttal](#)

Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act, Ameren Illinois Company, Docket No. 22-0063 On Behalf of NRDC

Demand Response and Electric Vehicle Performance metrics
[Direct](#) | [Rebuttal](#)

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief, U-21148, On Behalf of NRDC

Performance-based regulation and gas decarbonization
[Direct](#)

Phase 2: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal (D.P.U 21-92) On Behalf of the Attorney General's Office

EV Program Design and Load Management
[Direct](#)

Expert Testimony (Continued)

Phase 2: Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-91) On Behalf of the Attorney General's Office

EV Program Design and Load Management

Direct

Phase 2: Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-90) On Behalf of the Attorney General's Office

EV Program Design and Load Management

Direct

Phase 1: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal (D.P.U 21-92) On Behalf of the Attorney General's Office

EV Program Design and Load Management

Direct

Phase 1: Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-91) On Behalf of the Attorney General's Office

EV Program Design and Load Management

Direct

Phase 1: Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-90) On Behalf of the Attorney General's Office

EV Program Design and Load Management

Direct

In the Matter of the Petitions for Recovery of Certain Gas Costs (DKT: 21-138, 21-235, 21-610, 21-611) On Behalf of The Citizens Utility Board of Minnesota

Prudency Review

Direct

Ron Nelson
Senior Director



Expert Testimony (Continued)

In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Rates for Natural Gas Utility Service in Minnesota (Docket No. 21-435) On Behalf of the Clean Energy Organizations

Rate Design and Line Extension Policy

Direct

In the Matter of the Petitions for Recovery of Certain Gas Costs (DKT: 21-138, 21-235, 21-610, 21-611) On Behalf of The Citizens Utility Board of Minnesota

Prudency Review

Direct

Green Mountain Power (DKT: 2021-3707-PET) On Behalf of Green Mountain Power

Multi Year Rate Plan

Prefiled Direct Testimony

Public Service of Oklahoma (DKT: 202100055) On Behalf of AARP

ECOSS and Rate Design

Responsive Testimony

Duquesne Light Company (DKT: R-2021-3024750) On Behalf of the PA OCA

Transportation Electrification, Load Control

Direct | Surrebutal (note: please type in the docket number, the testimony cannot be directly referenced)

PECO (DKT: R-2021-3024601) On Behalf of the PA OCA

Transportation Electrification, Load Control

Direct (note: please type in the docket number, the testimony cannot be directly referenced)

Rocky Mountain Power (DKT: 20-035-04) On Behalf of the Utah Office of Consumer Services

Embedded COS, Rate Design, and AMI Rollout

Direct

Minnesota Power* On Behalf of the MN CUB

ECOSS and low-income rate design

Pennsylvania Power and Light: DER Management Petition (DKT: P-2019-3010128) On Behalf of the PA OCA

DER integration

Direct | Surrebutal (note: please type in the docket number, the testimony cannot be directly referenced)

Expert Testimony (Continued)

Public Service of New Hampshire (dba Eversource Energy) (DKT: DE 19-057) On Behalf of the NH OCA

Embedded and marginal COS, Rate Design, and PBR

[Direct](#)

Liberty Utilities (DKT: DE 19-064) On Behalf of the NH OCA

Marginal COS, Rate Design, decoupling and PBR

[Direct](#)

*Settled before direct was filed

Oklahoma Gas and Electric (DKT: 201800140) On Behalf of AARP

Rate Design and CCOSS

[Direct](#)

Vectren Energy Delivery of Ohio (DKT: 18-0298-GA-AIR) On Behalf of the Environmental Law and Policy Center

CCOSS and Rate Design

[Direct](#) | [Supplemental](#) | [Case link](#)

Commonwealth Edison (DKT: 18-0753) On Behalf of the IL AG

Distributed Generation Rebates and Smart Inverter Specifications

[Direct](#) | [Rebuttal](#) | [Case link](#)

Ameren Illinois Company (DKT: 18-0537) On Behalf of the IL AG

Distributed Generation Rebates and Smart Inverter Specifications

[Direct](#) | [Rebuttal](#) | [Case file](#)

Public Service Company of Oklahoma (DKT: 201800096) On Behalf of AARP

Formula Rates, Performance Metrics, Rate Design, and CCOSS

[Direct](#)

Oklahoma Gas and Electric (DKT: 201700496) On Behalf of AARP

CCOSS and Revenue Apportionment

[Responsive](#) | [Case link](#)

Minnesota Power (DKT: E-002/GR-16-664) On Behalf of the MN OAG

CCOSS, Rate Design, and the Utility Business Model

[Surrebuttal](#) | [Rebuttal](#) | [Testimony](#) | [Case Link](#)

Ron Nelson
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Expert Testimony (Continued)

Otter Tail Power (DKT: E-002/GR-15-1033) On Behalf of the MN OAG
Marginal and Embedded CCOSS and Rate Design
[Opening Statement](#) | [Direct](#) | [Rebuttal](#) | [Case link](#)

Xcel Energy (DKT: E-002/GR-15-826) On Behalf of the MN OAG
CCOSS, Rate Design, and Performance-Based Regulation
[Direct](#) | [Rebuttal](#) | [Surrebuttal](#) | [Case link](#)

Minnesota Energy Resources Corp. (DKT: G-011/GR-15-736) On Behalf of the MN OAG
CCOSS and Rate Design
[Direct](#) | [Rebuttal](#) | [Surrebuttal](#) | [Case link](#)

CenterPoint Energy (DKT: E-002/GR-15-424) On Behalf of the MN OAG
CCOSS and Rate Design
[Opening Statement](#) | [Direct](#) | [Rebuttal](#) | [Surrebuttal](#) | [Case link](#)

Dakota Energy Association (DKT: E-002/GR-14-482) On Behalf of the MN OAG
CCOSS and Rate Design
[Direct](#) | [Rebuttal](#) | [Surrebuttal](#) | [Case link](#)

Xcel Energy (DKT: E-002/GR-13-868) On Behalf of the MN OAG
CCOSS and Rate Design
[Direct](#) | [Rebuttal](#) | [Surrebuttal](#): [Case Link](#)

Xcel Energy, Minnesota Energy Resources Corp, CenterPoint Energy (DKT: 21-138)
Natural Gas Prudence Testimony
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Customer Charge Resolution - 2015-1

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Customer Charge Resolution - 2015-1

NASUCA Customer Charge Resolution-2015-1

THE NATIONAL ASSOCIATION OF

STATE UTILITY CONSUMER ADVOCATES

RESOLUTION 2015-1

OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE

DELIVERY SERVICE CUSTOMER CHARGES

Whereas, the National Association of State Utility Consumer Advocates ("NASUCA") has a long-standing interest in issues and policies that ensure access to least-cost gas and electric utility services, which are basic necessities of life in modern society; and

Whereas, in recent years, gas and electric utilities have sought to substantially increase the percentage of revenues recovered through the portion of the bill known as the customer charge, which does not change in relation to a residential customer's usage of utility service, through proposals to increase the customer charge or through the imposition of what have been called Straight Fixed Variable or SFV rates; and

Whereas, these gas and electric utilities have sought to justify such increases by arguing that all utility delivery costs are "fixed" and do not vary with the volume of energy supply delivered to customers, and that reductions in customer usage due to conservation and energy efficiency increase the risk of non-recovery of utility costs; and

Whereas, based on these arguments, these gas and electric utilities have proposed that a greater percentage of utility costs (distribution costs such as electric transformers and poles and natural gas mains, traditionally recovered through volumetric rates) should be collected from customers through flat, monthly customer charges; and

Whereas, gas and electric utilities' own embedded cost of service studies,

[1] in fact, show that a substantial portion of utility delivery service costs are usage-related, and therefore, subject to variation based on customer usage of utility service; and

Whereas, increasing the fixed, customer charge through the imposition of SFV rates or other high customer charge structures creates disproportionate impacts on low-volume consumers within a rate class, such that the lowest users of gas and electric service shoulder the highest percentage of rate increases, and the highest users of utility service experience lower-than-average rate increases, and even rate decreases,[2] in some instances; and

Whereas, nationally recognized utility rate design principles call for the structuring of delivery service rates that are equitable, fair and cost-based; and

Whereas, SFV and other high customer charge rate design proposals, in which low-use customers would see greater than average increases, while high-use customers would experience lower-than-average increases and even decreases in their total distribution bill, are unjust and inconsistent with sound rate design principles; and

Whereas, data collected by the U.S. Energy Information Administration show that in a vast majority of regions called "reportable domains,"[3] low-income customers (with incomes at or below 150% of the federal poverty level) on average use less electricity than the statewide residential average and less than their higher-income counterparts:[4] and

Whereas, these data also show that in every reportable domain but one, elderly residential customers (65 years of age or older) use less electricity on average than the statewide residential average and less than their younger counterparts:[5] and

Whereas, these data also show that in a vast majority of reportable domains, minority (African American, Asian and Hispanic) utility customers on average use less electricity than the statewide residential average and less than their Caucasian counterparts:[6] and

Whereas, data from the U.S. Department of Energy's Residential Energy Consumption Survey for the Midwest Census region, show that natural gas consumption increases as income increases, and that higher incomes lead to occupation of larger sizes of housing units,[7] thereby increasing the likelihood of higher gas utility usage, and that natural gas usage increases as income increases in the vast majority of reportable domains throughout the U.S.:[8] and

Whereas, given these documented usage patterns, the imposition of high customer charge or SFV rates unjustly shifts costs and disproportionately harms low-income, elderly, and minority ratepayers, in addition to low-users of gas and electric utility service in general; and

Whereas, because the imposition of high customer charge or SFV rates results in a smaller percentage of a customer's utility bill consisting of variable usage charges, customers' incentive to engage in conservation as well as federal and state energy efficiency programs is significantly reduced; and

Whereas, NASUCA supports the adoption of cost-effective energy efficiency programs as a means to reduce customer utility bills, help mitigate the need for new utility infrastructure, and provide important environmental benefits; and

Whereas, given that the imposition of high customer charge or SFV rates means that a smaller percentage of a customer's utility bill is derived from variable usage charges, the imposition of SFV-type rates reduces the ability of utility customers to manage and control the size of their utility bills;

Now, therefore, be it resolved, that NASUCA continues its long tradition of support for the universal provision of least-cost, essential residential gas and electric service for all customers;

Be it further resolved, that NASUCA opposes proposals by utility companies that seek to increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills and the imposition of SFV rates;

Be it further resolved, that NASUCA urges state public service commissions to reject gas and electric utility rate design proposals that seek to substantially increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills – proposals that disproportionately and inequitably increase the rates of low usage customers, a group that often includes low-income, elderly and minority customers, throughout the United States;

Be it further resolved, that state public service commissions should promote and adopt gas and electric rate design policy that minimizes monthly customer charges of residential gas and electric utility customers in order to ensure that delivery service rates are equitable, cost-based, least-cost, and encourage customer adoption of conservation and federal and state energy efficiency programs.

Be it further resolved that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution.

Submitted by Consumer Protection Committee

Approved June 9, 2015

Philadelphia, Pennsylvania

No Vote: Wyoming

Abstention: Vermont

[1]See, e.g., Illinois Commerce Commission Docket No. 14-0244/0225, *Peoples Gas Light & Coke Co. – Proposed Increase in Delivery Service Rates*, PGL Ex. 14.2, p. 1, lines 8, 14, 38 and 42, col. D; Illinois Commerce Commission Docket No. 13-0384, *Commonwealth Edison Company*, AG Ex. 1.0 at 12-13, citing ComEd Ex. 3.01, Sch. 2A, p. 13, col. Tot. ICC, line 248.

[2]ICC Docket No. 14-0224/0225, AG Ex. AG/ELPC Ex. 3.0 at 15, 25.

[3]The U.S. Energy Information Administration's Residential Energy Consumption Survey provides detailed household energy usage and demographic data for 27 states or regions of the U.S. referred to as "reportable domains."

[4]See Wis. Pub. Serv. Com'n Docket No. 3270-UR-120, *Application of Madison Gas and Electric Co. for Authority to Adjust Electric and Natural Gas Rates*, Public Comments of John Howat, National Consumer Law Center, October 3, 2014, citing 2009 U.S. EIA Residential Energy Consumption Survey data by "Reportable Domain" at 5-6.

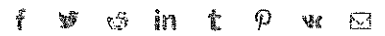
[5]*Id.* at 7-8.

[6]U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

[7]See ICC Docket No. 14-0224/0225, *North Shore Gas, Peoples Gas Light & Coke Company – Proposed Increase in Gas Rates*, AG Ex. 4.0 at 11-12; AG Ex. 4.1, RDC-5, p.1-3.

[8]U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

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