PUBLIC VERSION

BEFORE THE
NORTH DAKOTA
PUBLIC SERVICE COMMISSION

In the Matter of the Application of	§	
Otter Tail Power Company	§	CASE NO. PU-17-398
For Authority to Increase Rates for	§	
Electric Utility Service in North Dakota	§	

DIRECT TESTIMONY

AND SUPPORTING EXHIBITS

OF DAVID E. DISMUKES, PH.D.

May 18, 2018

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I. Introduction

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place, Suite 5-F, Baton Rouge, Louisiana, 70808. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, which is located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University ("LSU"). I am also a full Professor in the Department of Environmental Sciences and Director of the Coastal Marine Institute in the College of the Coast and Environment at LSU. I also serve as an Adjunct Professor in the E. J. Ourso College of Business (Department of Economics), and I am a full member of the graduate research faculty at LSU. Appendix A provides my academic vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. FOR WHOM ARE YOU APPEARING?

A. I am testifying on behalf of the North Dakota Public Service Commission Advocacy Staff ("Staff"). My testimony and 15 schedules in this matter were prepared by me or under my direct supervision and control.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION?

A. No, I have not.

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by Staff to provide an expert opinion on the Otter Tail Power Company's ("OTP" or the "Company") request for an increase in its electric rates. My testimony will address the Company's proposed cost of service study, rate design, economic development efforts, and other tariff revisions.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into the following sections:

- Section 2: Summary of Findings and Recommendations
- Section 3: Jurisdictional and Class Cost of Service Studies
- Section 4: Marginal Cost of Service Study
- Section 5: Revenue Distribution and Rate Design
- Section 6: Other Revisions to Tariffs and Riders
- Section 7: Proposed Economic Development Incentives
- Section 8: Conclusions and Recommendations

II. Summary of Findings and Recommendations

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS REGARDING THE COMPANY'S JCOSS.

A. I recommend that the Commission accept the Company's proposed jurisdictional allocations. The Company has adopted a uniform allocation method in both jurisdictions, and this methodology is comparable to what has historically been used in North Dakota. However, while I agree with the Company's proposed jurisdictional allocations there are some areas where the transparency of their analysis could be improved upon for

regulatory purposes. Therefore, I also recommend that the Commission order the Company to file, in its next rate case, a transparent JCOSS with cost allocation performed at the detailed FERC account level and that this analysis be provided in an electronic format separate from its CCOSS.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS REGARDING THE COMPANY'S CCOSS.

A. I recommend the Commission utilize a set of alternative CCOSS methodologies that includes: (1) a 12 coincident peak ("CP") methodology to allocate transmission plant costs; (2) a rejection of the Company's minimum system study for allocating distribution plant accounts 364-368; (3) a distribution plant allocation methodology that treats all plant investment as being demand and not customer related; and (4) a methodology that uses customer counts to allocate services-related plant. Furthermore, my review of the Company's CCOSS was significantly impaired by a lack of transparency and support documentation mapping cost of service allocators, and other crucial input data to FERC accounts. Therefore, I recommend that the Commission order the Company, in its next rate case, to file a transparent and comprehensive CCOSS that documents and maps costs and allocators at the FERC account level to each of its customer classes.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S MCCOSS.

A. I recommend that the Commission reject the Company's MCCOSS. The Company's MCCOSS is flawed and the Company's application of the MCCOSS results are subjective and arbitrary. I recommend that rate schedule revenue responsibilities be set upon the results of my alternative CCOSS and my proposed revenue distribution.

Furthermore, the Company's use of the MCCOSS as a basis for its proposed customer charge increases is faulty and, if accepted, would result in substantially large increases for many customer classes.

Q. PLEASE SUMMARIZE YOUR REVENUE DISTRIBUTION AND RATE DESIGN RECOMMENDATIONS.

A. I make the following revenue distribution and rate design recommendations:

- Class revenue responsibilities should be set using a two-step methodology. In the first step, under-earning classes should receive an increase equal the 1.25 times the system average increase. In the second step, any remaining revenue deficiency should be allocated to the remaining rate classes relative to their current test year revenues.
- Customer charges should be increased by the system average increase, except for the Residential Control Demand class which should receive a customer charge increase that is equal to the one proposed by the Company.
- Distribution rates should be increased according to the results of my proposed CCOSS with the prescribed increase allocated to the volumetric and demand components on an equal percentage basis.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S OTHER TARIFF REVISION PROPOSALS.

A. I make the following recommendations regarding the Company's other tariff revision proposals:

- The Company's Residential TOD tariff revisions should be rejected since the proposal is not based with any definitive evidence and relies almost exclusively on the results of the Company's flawed MCCOSS. If the Commission chooses to approve the

proposed tariff it should require the Company to file the results of its Pilot program within six months of its conclusion. I also recommend that the Commission reject the Company's proposed $20 meter removal fee since this is a pilot program and customer's should not be required to pay a meter removal fee should they find that the rates are not providing appropriate price signals.

- The Commission should reject the Company's Generation Cost Recovery Rider ("GCRR") proposal since the need for this rider has not been proven. If the Commission approves the GCRR, I recommend that GCRR cost recovery be limited to investments associated with the Astoria Project alone and that the GCRR be subject to a sunset review when the Astoria plant is moved into rate base at the time of the Company's next base rate case. Additionally, I recommend that a rate cap of two percent per year be set in this case for the allowed revenue requirement that can be recovered through the GRCC in any year.
- The Company's proposed LED tariff should be approved but the current outdoor lighting tariffs should remain open to all customers. No customers should be forced to take LED service as proposed by the Company.
- The Company's Air Conditioning Rider should be expanded to include an incentive for commercial customers.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S ECONOMIC DEVELOPMENT EXPENSES?

A. I recommend that the Commission reject the Company's proposal to include these expenses in rates. The Commission has clearly expressed concerns about including economic development expenses in rates in the past, particularly when the Company

cannot show a companion rate reduction benefit. The Company has not met the Commission's burden of proof for including these economic development expenses in rates, therefore, they should be excluded from rates.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED SUPER LARGE GENERAL SERVICE TARIFF?

A. I recommend that the Commission reject the Company's proposed Super Large General Service ("SLGS") tariff since it is potentially in conflict with an alternative economic development rider ("EDR") that is also being proposed by the Company in a separate proceeding. However, if the Commission decides to approve the SLGS rate schedule, I recommend the following provisions:

(1) require a regular review of each customer's contribution to the Company's revenue requirement and subsequent re-approval of the SLGS rate by the Commission;

(2) institute a penalty for customers who take service under the SLGS rate schedule and fail to meet the requirements, such as payment of the difference between the SLGS rate and the applicable rate schedule;

(3) limit the amount of time under which the customer can receive a favorable rate under the SLGS schedule to five years;

(4) require the Company to calculate the incremental cost of serving the prospective customer based upon the situational cost of establishing and providing service rather than relying upon the Company's MCCOSS; and

(5) require the customer to provide evidence of net benefits to ratepayers, such as jobs or capital investment in the Company's service territory.

III. Jurisdictional Cost of Service Study and Class Cost of Service Study

A. Introduction

Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A. A cost of service study ("COSS") is a method by which utility costs and revenues are reconciled across different jurisdictions and customer classes. The goal of a COSS is to determine the cost of providing service to either a particular jurisdiction or a particular customer class, and the revenue contribution each class makes to cover those costs. The results of these studies produce a rate of return and revenue requirement. The rate of return and revenue requirement can be used as a tool in developing the relative revenue responsibility and rates for each jurisdiction and/or for each rate class within a specific jurisdiction. In the current rate case, the Company provides both a jurisdictional ("jurisdictional cost allocation study") and a class COSS (or "CCOSS").

Q. HOW IS A COSS PREPARED?

A. Typically, a COSS is prepared by defining a set of cost information, and then (1) "functionalizing" the cost information; (2) "categorizing" the cost information; and (3) "allocating" the cost information. The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e. production, transmission, and distribution). The next step of the process "categorizes" each of these respective costs into a particular type of cost, including those that are either demand-related, commodity-related, or customer-related. The last step of the process "allocates" each of these costs to a respective jurisdiction or customer class as appropriate.

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY DEMAND-RELATED COSTS?

A. Yes. Demand-related costs are associated with meeting maximum energy demands. Electric substations and line transformers at the distribution level are designed, in part, to meet the maximum customer demand requirements. The most common demand allocation factors used in a COSS are those related to system coincident peaks ("CP") or non-coincident customer class peaks ("NCP").

Q. HOW ARE ENERGY-RELATED COSTS DEFINED?

A. Energy-related costs are defined as those that tend to change with the amount of electricity (i.e., kWh) sold. Electric generation costs and high-voltage transmission lines, for instance, can be allocated, in part, based on some measure of electricity sales.

Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. IS THIS A RELATIVELY SIMPLE PROCESS?

A. No. Some costs can be clearly identified and directly assigned to a function or category, while other costs are more ambiguous and difficult to assign. The primary challenge in conducting a COSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize. Therefore, unique allocation factors are utilized in a COSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and is often imbued with policy considerations.

Q. HOW DOES A COSS RELATE TO COMMONLY-QUOTED ECONOMIC PRINCIPLES?

A. A COSS can also be referred to as a "fully allocated cost study" since it allocates test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the COSS is to estimate the cost responsibility for various jurisdictions and customer classes, which in turn are used to develop rates. At the core of a COSS is a set of historic book costs for a utility that have accumulated over decades. Rates are, therefore, based upon historic average costs; whereas, economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, regulated utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with a number of joint and common costs, difficult. This problem is exacerbated by the fact that the cost information utilized in a COSS are usually historic and static, not dynamic and forward-looking. These analytic deficiencies undermine many experts' cost causation/pricing claims. As a result, in regular practice there is no single correct answer that is revealed in a COSS. It is often up to regulators to exercise an appropriate level of judgment regarding the nature of these costs, the results of the COSS, and the implications both have in setting fair, just, and reasonable rates. This is one of the reasons why many regulators use COSS results as a "guide" in setting rates, and are not unnecessarily bound by their results.

Q. WHAT CONTROVERSIES ARISE IN THE ANALYSIS AND COMPARISON OF VARIOUS COSS METHODOLOGIES?

A. The COSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two activities are dedicated to determining how much revenue will be recovered through rates, the COSS process determines how those costs (revenue requirements) will be recovered, through which jurisdiction, and eventually which customer rates. The primary controversy with the evaluation of various COSS results often rests with determining whether costs (revenue requirements) will be recovered by the relative customer share of each class, the peak load contributions of each customer class, or whether and how the approach will be tempered through the use of customer, peak, and off-peak usage considerations. Methodologies that are heavily-biased toward customer and peak considerations, for instance, can tend to prejudice relatively lower load-factor customers, such as residential and small commercial customers, and preference larger customer classes and off-peak customers. These approaches can also fail to capture the service being provided by the utility (*i.e.*, electric distribution service in this case), and how the value of that service varies by the amount purchased by different customer classes.

B. Jurisdictional Cost of Service

Q. WHAT IS THE GENERAL PURPOSE OF A JURISDICTIONAL COSS?

A. A jurisdictional cost allocation study attempts to determine the appropriate revenue requirement associated with a utility's costs to serve each of its jurisdictions. Uniformity can be an important part of this jurisdictional cost estimation process. It is important to use uniform (or consistent) data and to use uniform allocation methodologies across jurisdictions. If a utility does not adopt uniform data or methodologies across its

jurisdictions, it could easily over- or under-recover its cost of service on a system-wide basis.

Q. HAS THE COMPANY RECENTLY FILED A FULL RATE CASE IN ANOTHER JURISDICTION?

A. Yes. On February 16, 2016, the Company filed a general rate proceeding before the Minnesota Public Utilities Commission ("MPUC")[1] which included, among other things, a jurisdictional cost of service study ("JCOSS") and a class cost of service study ("CCOSS") and a marginal cost of service study ("MCCOSS"). In its MPUC filing, the Company indicated that it utilizes uniform procedures in all its state jurisdictions in order to adequately recover its cost of providing retail service across its entire service territory and to minimize the potential for "over" or "under" recovery between its respective jurisdictions.[2]

Q. DID THE MPUC APPROVE THE COMPANY'S JURISDICTIONAL ALLOCATIONS?

A. Yes, that appears to be the case despite the fact there is no explicit discussion of the Company's JCOSS in the MPUC's final order. The Company noted in its filing that its proposed JCOSS was consistent with the methods used in its prior rate case.[3]

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[1] *See Minnesota P.U.C. Docket No. E-017/GR-15-1033, In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*; Testimony Volume 2A, filed February 16, 2016.

[2] Minnesota P.U.C. Docket No. E-017/GR-15-1033, In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota; Direct Testimony of Peter Beithon, filed February 16, 2016, 46:7-9.

[3] Minnesota P.U.C. Docket No. E-017/GR-15-1033, In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota; Direct Testimony of Peter Beithon, filed February 16, 2016, 46:27-28.

Additionally, the Minnesota Commission has noted the importance of consistency both between jurisdictions and between filings.[4]

Q. HOW DOES THE COMPANY'S MINNESOTA JURISDICTIONAL ALLOCATION PROPOSALS COMPARE TO ITS CURRENT PROPOSAL IN NORTH DAKOTA?

A. The Company has filed a copy of its Cost Allocations Procedures Manual ("CAPM") in both the proceeding before the MPUC and in this proceeding. A review of the CAPM filed in Minnesota and North Dakota shows that the same cost allocation procedures are used in both jurisdictions.

C. Jurisdictional Cost of Service Recommendations

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED JURISDICTIONAL COST ALLOCATION STUDY?

A. I recommend that the Commission accept the Company's proposed jurisdictional allocations. The Company has adopted a uniform allocation method in both jurisdictions, and this methodology is comparable to what has historically been used in North Dakota. However, while I agree with the Company's proposed jurisdictional allocations there are some areas where the transparency of their analysis could be improved upon for regulatory purposes. Therefore, I also recommend that the Commission order the Company to file, in its next rate case, a transparent JCOSS with cost allocation performed at the detailed FERC account level and that this analysis be provided in an electronic format separate from its CCOSS.

[4] Minnesota P.U.C. Docket No. E-017/GR-10-239, In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota; Order, April 25, 2011, p. 21.

D. Class Cost of Service Study

Q WHAT IS THE PURPOSE OF THE COMPANY'S PROPOSED CCOSS?

A. The Company's CCOSS has been developed in order to allocate costs across its customer rate classes in order to determine current class-specific rates of return and potential cost recovery deficiencies. The CCOSS can also be used as a means of allocating the Company's estimated revenue deficiency to its respective customer classes. The Company's proposed CCOSS represents its embedded cost of service and is based upon historic booked costs, as noted earlier in my testimony.

Q. PLEASE DESCRIBE THE DEMAND ALLOCATORS USED WITHIN THE COMPANY'S CCOSS.

A. The Company uses four separate demand allocators within its CCOSS. The first, referred to as its "D1" allocator, is used to assign costs associated with the Company's production plant, and is based on each class' contribution to the Company's average annual six-hour system peak kW demand. The second, referred to as its "D2" allocator, is used to assign costs associated with the Company's transmission plant, and is based on each class' contribution to the system average annual six-hour system transmission peak kW demand. The third, referred to as the "D3" allocator, is used to assign primary distribution plant costs, and is based upon each class' contribution to system average annual six-hour system distribution peak kW demand. The fourth, referred to as the "D4" allocator, is used to assign secondary distribution plant costs, and is based on non-coincident kW demands at the secondary service level.[5]

[5] Direct Testimony of Gina Ice, Exhibit GSI-1, Schedule 2.

Q. DO YOU DISAGREE WITH ANY OF THE ASSUMPTIONS OR ALLOCATION FACTORS INCORPORATED IN THE COMPANY'S PROPOSED CCOSS?

A. Yes. I disagree with the use of several of the Company's CCOSS allocation factors including the: (1) the transmission plant allocators, and (2) the allocation of portions of the Company's distribution plant using a minimum size system approach. I will address each of these flaws later in this section of my testimony and my alternative allocation factor recommendations.

1. <u>Allocation of Production Plant</u>

Q. PLEASE DESCRIBE THE COMPANY'S D1 ALLOCATOR.

A. The D1 allocator used to allocate production plant in the Company's CCOSS is comparable to the D1 allocator used in its JCOSS. The D1 allocator is based upon the Company's retail load and is calculated as each class' contribution to the system average annual six-hour system peak kW demand. The D1 allocator is based on the Company's six-hour coincident peak ("6-HOURCP" allocator). The hours ending 9:00, 10:00, and 11:00 a.m., and 6:00, 7:00, and 8:00 p.m. were averaged to develop the D1 allocation factor.[6] This allocation factor is used to allocate 22 percent of the Company's production plant to all retail customer classes.

Q. PLEASE DESCRIBE HOW THE COMPANY ALLOCATES THE REMAINING PORTIONS OF ITS PRODUCTION PLANT.

A. The Company allocates the remaining 78 percent of its production plant based upon two differing allocators it refers to as a "base demand" allocator and a "base energy (wind)" allocator. The Company uses what it refers to as an "E8760" allocation factor to

[6] Direct Testimony of Gina Ice, Exhibit GSI-1, Schedule 2, p. 2.

allocate the remaining base demand and base energy portion of its production plant.[7] The E8760 allocator is designed to apply a weighted average cost factor to each kWh of energy consumed in each hour of the year based upon changes in the hourly cost of energy.[8] This E8760 allocators has two parts: E1-E8760 and E2-E8760, to allocate, respectively, the base demand (E1-E8760) and base energy (Wind, E2-E8760) portions of its production plant.[9]

Q. HOW DID THE COMPANY DEVELOP ITS E8760 ALLOCATION FACTORS?

A. The Company's E8760 allocator factors are derived from five separate calculations/adjustments. First, the Company utilizes class-based load shapes for each hour in a year based upon its load research data.[10] Second, the Company takes its most recent 2018 annual sales forecast, on a per class basis, and sculpts that annual forecast based on the 2016 load shapes. Third, the Company takes the product of its 2018 estimated hourly class-specific loads and 2018 hourly forecast MISO Day Ahead Locational Marginal Prices ("LMP") for the OTP load zone. This third step yields an hourly per class total cost (i.e., the product of a unit cost and a class-specific hourly loads). Fourth, the Company sums class-specific hourly costs to get a total Company hourly energy cost. Lastly, the Company develops a ratio of class-specific total energy costs by taking the quotient of these two respective series.[11]

Q. DOES THE COMPANY USE THE E8760 ALLOCATION FACTOR TO ALLOCATE ANY OTHER COSTS IN THE COMPANY CCOSS?

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[7] Direct Testimony of Gina Ice, Table 1, 3:12.
[8] Direct Testimony of Gina Ice, 5:15-17.
[9] Direct Testimony of Gina Ice, Table 1, 3:12.
[10] The Company states that 2016 was the most recent year in which one full year of data was available.
[11] The Direct Testimony of Gina Ice, 6:1-13.

A. Yes. The Company also uses the E8760 allocator to allocate fuel costs in its Energy Adjustment Rider ("EAR").[12]

Q. IS THE COMPANY'S E8760 ALLOCATOR CONSISTENT WITH THE COMMISSION'S LAST RATE CASE ORDER?

A. Yes. The Company, as part of the approved settlement agreement in its last rate case, was required to use E8760 allocators for certain production plant items in its CCOSS as well as to allocate fuel cost to customer classes in its EAR.[13] The Company has used the E8760 allocation factor in its current CCOSS in a manner consistent with the agreed upon terms of the approved settlement agreement in the Company's last rate case.

Q. PLEASE EXPLAIN HOW PRODUCTION PLANT ACCOUNTS ARE TYPICALLY ALLOCATED.

A. Production plant costs are usually allocated, in very large part, to customer classes on a cost basis. There are, however, a number of methods that can be used to allocate production plant costs including those that focus on peak demand measures and others that focus on factors that incorporate various energy measures.

Q. PLEASE EXPLAIN HOW DEMAND MEASURES ARE USED TO ALLOCATE PRODUCTION PLANT.

A. Peak demand methods classify all production plant accounts as demand-related with each class receiving a share of those plant costs based upon its contribution to system peak. Some examples of peak demand methods include the single coincident

[12] Direct Testimony of Gina Ice, 6:19-22.
[13] Case No. PU-08-862, Otter Tail Corporation Electric Rate Increase Application, Order on Settlement, Amended Settlement Agreement, November 25, 2009, p.8.

peak method, summer and winter peak method, and twelve-month coincident peak method.

Q. PLEASE EXPLAIN HOW ENERGY WEIGHTED MEASURES ARE USED TO ALLOCATE PRODUCTION PLANT.

A. Energy-weighted methods recognize that energy loads are an important contributing factor of production plant costs and classify a portion, but not all, of these production costs as energy-related. These methods usually use combinations of both peak demand and energy usage measures to allocate production plant costs. The energy component of these measures are usually embedded in the simple averages or weights used to develop the composite allocation factor. Some examples of energy weighted methods include: the average and excess method; "equivalent peaker" method; and the average and peak method.[14]

Q. DO YOU AGREE WITH THE COMPANY'S ALLOCATION OF PRODUCTION PLANT USING THE E8760 ALLOCATION METHOD?

A. No, not entirely. The Company's method, admittedly, is consistent with the Commission's order in its last rate case approving the settlement between parties. The Commission needs to be mindful, however, that there are other ways in which energy-related costs can be blended into a CCOSS, many of which are more common than the strict energy based allocator used by the Company (i.e., the E8760 allocator). This appears to be a fact not lost on the Company considering that OTP had historically

[14] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p 41.

allocated production plant costs using an energy-weighted "Equivalent Peaker" methodology in the past.[15]

Q. ARE YOU RECOMMENDING A CHANGE IN HOW THE COMPANY ALLOCATES ITS PRODUCTION PLANT COSTS?

A. No, I am not recommending that the Company change the method it uses for allocating its production plant costs in this proceeding. The Company's use of coincident peak to allocate its peak demand portion of its production plant appears to be necessary in order to recognize the demand related portion of production plant that is not considered in the Company's E8760 allocation method. Although I am not recommending a change in this proceeding, I do believe that some of the more generally accepted energy weighting allocation methods that I have mentioned earlier may be just as effective and less data intensive for allocating production plant costs. Energy weighting methods recognize that energy loads are also a contributing factor of production plant costs. These energy weighting methods consider that some production plant costs are incurred in order to provide adequate capacity during peak periods while other production plant costs are incurred as a result of the need to provide energy at all hours of the day.

2. <u>Allocation of Transmission Plant</u>

Q. PLEASE DESCRIBE THE COMPANY'S D2 ALLOCATOR.

A. The Company uses the D2 allocation factor to allocate its transmission plant. The D2 factor is calculated using the same six hours as the D1 allocation factor except that

[15] Minnesota Public Service Commission, Case No. GR-10-239, In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota, Findings of Facts, Conclusions and Order, April 25, 2011, p.19.

the demand used for this transmission allocation factor is measured at the transmission level and not the production level.[16]

Q. PLEASE EXPLAIN HOW TRANSMISSION FACILITIES ARE TYPICALLY ALLOCATED?

A. Higher-voltage transmission systems are designed to meet broader, less localized demands that are often measured by more diversified demand metrics such as a CP demand on a singular or an average basis.[17] The Federal Energy Regulatory Commission ("FERC") has historically used a 12CP methodology for the transmission plant costs in determining wholesale rates.[18] The FERC has used a 12CP methodology stating that it believes "the majority of utilities plan their systems to meet their twelve monthly peaks" rather than to meet a single peak.[19]

Q. HAS THE COMPANY PROVIDED ANY INFORMATION ON HOW IT PLANS AND DEVELOPS ITS OWN TRANSMISSION FACILITIES?

A. Yes. The Company indicates that it must meet the applicable requirements of the North American Electric Reliability Corporation ("NERC") reliability standards.[20] The Company states that NERC's Transmission Planning ("TPL") standard requires the Company to perform transmission planning studies annually to evaluate how the system will respond during scheduled maintenance, unscheduled outages, different generation

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[16] Direct Testimony of Gina Ice, Exhibit GSI-1, Schedule 2, p. 2.
[17] National Association of Regulatory Utility Commissioners ("NARUC"), Electric Utility Cost Allocation Manual, January 1992, pp. 77-83.
[18] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540-01, at 21598-21599 dated May 10, 1996.
[19] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540-01, at 21599 dated May 10, 1996.
[20] Company's response to ND-PSC-13.02.

dispatches, and various load levels.[21] Additionally, the Company states that the TPL standard requires the transmission planning studies to include various load levels.[22] In the past, the Company has identified in the models used for its transmission planning studies, new transmission plant investments that represent either peak load conditions or off-peak load conditions.[23] The Company states that its primary objective "is to ensure a reliable transmission system is planned that meets the requirements of the TPL standard, which addresses various system conditions throughout the planning year."[24]

Q. HAS THE COMPANY PROVIDED ANY INFORMATION ON HOW IT ALLOCATES ITS TRANSMISSION PLANT FACILITIES IN ITS FERC RATE FILINGS?

A. No, at least not in a direct fashion. The Company indicates that it uses a formula rate methodology template to set rates in its MISO tariff.[25] The Company also provided a link to where these templates and workpapers are available on MISO's website.[26] A review of the various templates, workpapers, and discovery responses indicate that the Company uses a 12CP allocation factor to allocate its transmission costs.[27]

Q. DO YOU AGREE WITH THE COMPANY'S ALLOCATION OF TRANSMISSION PLANT?

A. No. The Company proposes to use a transmission plant allocation methodology that is based on its six-hour coincident peak demand: this method contradicts how

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[21] Company's response to ND-PSC-13.02.
[22] Company's response to ND-PSC-13.02.
[23] Company's response to ND-PSC-13.02.
[24] Company's response to ND-PSC-13.02.
[25] Company's response to ND-PSC-13.01.
[26] Company's response to ND-PSC-13.01.
[27] Company's response to ND-PSC-13.01. See also: https://www.misoenergy.org/markets-and-operations/ts-pricing/to-rate-data/otter-tail-power-company-otp/#nt=%2Frateyear%3A2018&t=10&p=0&s=tsposteddate&sd=desc, Attachment 2016 Actual Attachments O GG MM 12.38 ROE - Final 12.12.17.

transmission costs are allocated by the FERC as well as how the Company plans for, and develops, its own transmission investments. For instance, the Company states that one of its primary transmission investment planning objectives is to address various system conditions throughout the planning year, not just in a handful of hours.[28] Therefore, I recommend that the Company use a 12CP method to allocate transmission plant consistent with that used by the FERC as well as many other regulated utilities.

3. Allocation of Distribution Plant

Q. PLEASE DESCRIBE HOW THE COMPANY CLASSIFIES CUSTOMER AND DEMAND COMPONENTS ASSOCIATED WITH DISTRIBUTION PLANT.

A. As previously stated the second process in a CCOSS is to categorize or classify costs as those that are demand-related, energy-related, or customer-related. The Company utilizes a minimum-size system approach to classify distribution plant items in FERC accounts 364 – 369 as being either demand or customer-related costs.

Q. PLEASE DESCRIBE THE MECHANICS OF A MINIMUM-SIZE SYSTEM STUDY ("MSS").

A. Many distribution system assets can be classified as having both a customer and an energy component. For instance, distribution substations are built to serve customers, but are often expanded to meet increases in customer loads. A MSS study attempts to separate the customer-related portion of total system costs from those associated with serving loads (or service volumes). A MSS study estimates the hypothetical minimum costs of developing a system to serve customers with no load. These calculations can include subjectivity through the use of accounting and engineering analyses to develop

[28] Company's response to ND-PSC-13.02.

assumptions about the minimum sizes and costs associated with various distribution system components, while still satisfying system requirements such as pole height and efficient conductor and transformer sizes. The costs associated with these "minimum" components are then added together to derive the total minimum costs associated with the hypothetical system with no energy usage. This estimate is then divided by total actual system costs in order to approximate the customer-related share of overall distribution system costs.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COMPANY'S MSS STUDY.

A. The MSS study found that 28.62 percent of costs associated with Account 364 (Poles, Towers and Fixtures) at the primary-voltage level were customer-related as opposed to demand-related.[29] Similarly, the MSS study found that at the primary distribution level, 13.06 percent of costs associated with Account 365 (Overhead Conductors and Devices), and 65.06 percent of the costs associated with Account 367 (Underground Conductors and Devices) are customer-related.[30] At the secondary-voltage level, the MSS found that 6.11 percent of Account 365 (Overhead Conductors and Devices) are customer-related.[31] In regards to Account 368 (Line Transformers), the MSS study showed that 36.14 percent of account costs are customer-related as opposed to demand-related.[32] Finally, the Company's MSS found that Account 369 (Services) that 32.68 percent of Overhead services and 66.17 of Underground services are customer related.[33]

[29] Company's response to ND-PSC-04.31, Attachment 1 to DR ND-PSC-04.31.xlsx.
[30] Company's response to ND-PSC-04.31, Attachment 1 to DR ND-PSC-04.31.xlsx.
[31] Company's response to ND-PSC-04.31, Attachment 1 to DR ND-PSC-04.31.xlsx.
[32] Company's response to ND-PSC-04.31, Attachment 1 to DR ND-PSC-04.31.xlsx.
[33] Company's response to ND-PSC-04.31, Attachment 1 to DR ND-PSC-04.31.xlsx.

Q. WHAT CONCERNS DO YOU HAVE WITH THE COMPANY'S USE OF AN MSS?

A. The Company's use of an MSS, and its resulting cost-allocations, is based on two faulty premises. First, the Company fails to account for the hypothetical nature of MSS analyses, and the well-recognized theoretical challenges and lack of applied regulatory policy support associated with these types of studies. Second, the Company does not consider the distribution plant items identified as customer related in its MSS in the determination and development of customer charges for each of its rate classes.

Q. ARE THERE ANY THEORETICAL SHORTCOMINGS ASSOCIATED WITH THE USE OF MSS-BASED DISTRIBUTION PLANT ALLOCATORS?

A. Yes. MSS-based analyses deal in hypotheticals that often do not exist in the real world, including the assumption that somehow and somewhere there exists an electric distribution system that could be plausibly built to serve customers but not load. No such system exists, making the underlying assumptions and modeling of a "minimum system" difficult, if not impossible, to verify. Even if a minimum electric distribution system could be constructed in real life, it would still have the ability to serve some customer loads, undermining this modeling approach's fundamental premise. Further, even if all of the practical problems contained within a MSS-based methodology could be corrected, it would still be irreconcilably flawed, since a MSS-based approach attempts to model an empirical relationship that has been shown to not exist and is often based upon a high degree of subjectivity in defining a specific "minimum system."

Q. CAN YOU PLEASE EXPLAIN HOW THE COMPANY CONSTRUCTED ITS MSS?

A. Yes. The Company states that its accounting system is somewhat limited and has aggregate, per account unit costs (i.e., average installed/book unit costs) and not asset specific unit costs. This limitation restricts the degree to which the Company can isolate certain types of smaller assets that could be used to empirically "construct" a "minimum" sized system. The one exception to this data limitation is for Account 368 (transformers) where the Company does appear to have per asset unit costs.[34]

Q. HOW DOES THE COMPANY WORK AROUND THIS DATA DEFICIENCY?

A. The Company's electric distribution ("ED") department defined what it believed was an appropriate "minimum system" and then identified the minimum size unit for each FERC distribution plant account. The ED department then identified, for each FERC distribution account, the total asset-specific investment, and the individual cost components of these unit investments (i.e., materials, labor).[35] Average asset ages, per relevant account, were then estimated using the results of the Company's most recently completed depreciation study. Asset ages from the deprecation study were subtracted from the study year in order to determine the year in which the average distribution unit/asset was installed.[36] The average installed cost of the minimum size distribution unit/asset was then adjusted in order to develop age-specific material, labor, transportation, and payroll costs.[37]

Q. HAS THE ACADEMIC LITERATURE IN UTILITY REGULATION QUESTIONED THE USE OF MSS STUDIES?

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[34] Direct Testimony of Gina Ice, Exhibit GSI-1, Schedule 2, Appendix A-1, p.1.
[35] Direct Testimony of Gina Ice, Exhibit GSI-1, Schedule 2, Appendix A-1, p.1.
[36] Direct Testimony of Gina Ice, Exhibit GSI-1, Schedule 2, Appendix A-1, p.1.
[37] Direct Testimony of Gina Ice, Exhibit GSI-1, Schedule 2, Appendix A-1, p.1.

A. Yes. Dr. James Bonbright, in his seminal work on public utility rates, raised a number of questions about the use of MSS methodologies in allocating costs. Bonbright's primary concern was the lack of empirical support in the academic literature for a causal relationship between distribution system costs and the number of customers. The true driving factors of utility distribution system costs are much more complicated and depend on a host of other factors, such as the size of a service territory and the population density within a utility's service territory, to name a few such factors. The incremental costs of constructing an appropriate distribution system to serve an additional customer within an urban area with existing nearby infrastructure is substantially less than the costs to extend an existing utility system by potentially miles to serve an additional customer located in a rural area, a fact inherently ignored by MSS methodologies.

> ...the annual costs of this phantom, minimum-sized distribution system are related as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their [minimum distribution costs] inclusion among the customer costs is defended on the grounds that, since they vary directly with the area of the distribution system (or else with the length of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the "zero-intercept" method whereby regression equations are run

relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).

What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customer per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[38]

Q. DOES THE COMPANY USE CUSTOMER DENSITY IN ITS ARGUMENTS CONCERNING CUSTOMER-RELATED COSTS?

A. Yes. The Company argues that "some of the costs recovered through fixed charges depend on customer density."[39] The Company argues that it must deploy larger, more numerous transformers, and asserts that "All else being equal, more and larger transformers would lead to higher fixed costs that are recovered through fixed charges."[40]

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[38] James C. Bonbright, et al. Principles of Public Utility Rates. 1988 Edition, p. 491.
[39] Direct Testimony of David G. Prazak at 20:15-16.
[40] Direct Testimony of David G. Prazak at 21:6-7.

Q. HAVE YOU CONDUCTED AN ANALYSIS EXAMINING THE COMPANY'S ARGUMENT?

A. Yes. Exhibit DED-1 calculates the number of transformers and total substation capacity per 1,000 customers for electric utilities who operate near the Company's service territory. Also shown are the residential and small commercial customer charges for these companies by state.

Q. WHAT DOES YOUR ANALYSIS SHOW?

A. My analysis shows that there is no obvious correlation between the number of transformers or the capacity of substations on a per-customer basis with the amount of a utility's fixed charges. For example, MDU Resources has 3.69 transformers per 1,000 customers, which is more than four times as many as the Company and is the highest number in the peer group. However, its residential monthly customer charges range from $5.17 to $25.00. ALLETE, Inc. has both a higher substation capacity and more transformers on a standardized basis than the Company, but its small commercial customer charge is just $10.50, less than half of what the Company is proposing. Finally, the two lowest residential customer charges are found in Montana and are from utilities that have relatively high substation capacity and number of transformers on a per-customer basis.

Q. DO UTILITIES WITH HIGH CUSTOMER DENSITY TEND TO HAVE LOW FIXED CHARGES?

A. Not necessarily. The second highest residential monthly customer charge belongs to Wisconsin Public Service Corporation at $21.00, but its substation capacity and number of transformers on a standardized basis are among the lowest on the chart.

Madison Gas and Electric has the lowest standardized substation capacity in the peer group, but its residential customer charge is the third-highest at $19.00.

Q. WHAT DO YOU CONCLUDE FROM YOUR ANALYSIS CONCERNING CUSTOMER DENSITY AND FIXED CHARGES?

A. My analysis shows that there is not a clear correlation between the density of a utility's customers and the amount of the utility's fixed charges. In fact, there may be a greater correlation between the amount of the fixed charges and the state in which the utility provides service.

Q. ARE THERE ANY OTHER AUTHORITATIVE SOURCES USED IN UTILITY REGULATION THAT ARE CRITICAL OF MSS STUDIES?

A. Yes. The NARUC Electric Cost Allocation Manual ("NARUC Electric Manual") contains a discussion on both the merits, as well as the potential problems of using an MSS approach to estimate customer-related electric distribution costs. For example, the NARUC Electric Manual recognized that even minimum-sized distribution equipment will contain a certain load-carrying capability.

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-

carrying capability, which can be viewed as a demand-related cost.[41]

Q. DID THE COMPANY ACCOUNT FOR THE LOAD-CARRYING CAPABILITIES OF ITS HYPOTHETICAL MINIMUM DISTRIBUTION SYSTEM?

A. Yes, the Company states that it has made a downward adjustment to both its Distribution Primary (D3) and Distribution Secondary (D4) allocation factors.[42] However, the Company has not provided any details on the calculation or the adjustment that was made even though it was asked to do so in discovery.[43] The Company simply states "adjustments are made during the process to calculate the historical demand allocation factors" and references a discovery attachment workpaper that provides hardcoded values with no illustration or discussion of any adjustments or assumptions.[44]

Q. ARE THERE ANY OTHER PROBLEMS ASSOCIATED WITH THE COMPANY'S PROPOSED MSS?

A. Yes. The Company's use of historical acquisition costs in its MSS is entirely inconsistent with the idea of a "minimum system" or "minimum system component." These historic investments were not made in a vacuum, independent of system size or system requirements. Thus, they can be upwardly biased as a replacement cost proxy for a "minimum system component." In other words, these investments were made to

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[41] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, p. 95.
[42] Company's response to ND-PSC-11.20.
[43] Company's response to ND-PSC-11.20, and Company's response to ND-PSC-4.25 and Attachment 1 to DR ND-PSC-04.25.
[44] Company's response to ND-PSC-11.20, and Company's response to ND-PSC-4.25 and Attachment 1 to DR ND-PSC-04.25.

serve the Company's existing and/or projected system loads, not some smaller, hypothetical minimum system with no load.

Q. HAS THE USE OF HISTORIC AVERAGES IN DETERMINING MINIMUM EQUIPMENT SIZE COSTS BEEN CRITICIZED IN THE NARUC ELECTRIC MANUAL?

A. Yes. The NARUC Electric Manual explicitly refers to the need to "take care" in utilizing an MSS to ensure that the results are representative of true minimum-sized distribution-related equipment, and not merely the minimum size stocked by the utility (*i.e.*, its historic distribution plant investments).[45] The manual explicitly notes:

> When applying [an MSS] approach, it is necessary to take care that the minimum size equipment being analyzed is, in fact, the minimum-sized equipment available, and not merely the minimum size stocked by or usually installed by the company. To the degree that the equipment being costed is larger than a true minimum, the minimum grid calculation will include costs more properly allocated to demand.[46]

Q. DOES THE COMPANY'S MSS PROVIDE ANY INFORMATION ON THE MINIMUM SIZED EQUIPMENT THAT WAS USED?

A. No. The Company's minimum system study uses an average physical age and the weighted cost of the equipment at that age, the amount of equipment in a one-mile surveyed area and work-order costs from 2015 to determine the cost of its various minimum size distribution system components. Although, the Company identifies the

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[45] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners ("NARUC"), p. 138.

[46] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners ("NARUC"), p. 138.

minimum sized equipment in the form of a code it has not provided any source documents or explanation or details on the size of this "minimum size equipment" nor does it appear that this minimum sized plant item has any actual bearing on the determination of the minimum costs.[47]

Q. IS THE COMPANY'S TREATMENT OF CUSTOMER COSTS CONSISTENT BETWEEN THE CCOSS, THE MSS AND THE METHOD IT USES TO SET CUSTOMER CHARGES??

A. No. Although the Company classifies a number of its distribution accounts as customer related and allocates these costs on a customer basis it does not actually define or apply these costs as customer related when determining its customer charge. The Company states that customer charges are set to recover three main components of its customer charge (1) investment in meter costs, (2) investment in meter service drops, and (3) O&M expenses including meter expenses, customer accounts expenses, and customer service expenses.[48] While the Company classifies and allocates portions of distribution plant accounts 364 (Poles, Towers and Fixtures), 365 (Overhead Conductors and Devices), 367 (Underground Conductors and Devices) and 368 (Line Transformers) as customer related, it does not consider or include these costs as part of its basis for setting customer charges. This further questions the legitimacy of using the MSS to classify costs as customer related and to allocate costs to customer classes when the Company clearly does not define nor consider these costs as customer related in developing and assigning customer charges.

[47] Company's response to ND-PSC-04.31.
[48] Company's response to ND-PSC-04.17.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE USE OF THE COMPANY'S MSS?

A. I recommend that the Commission reject the use of the Company's MSS in this proceeding. MSS methods are clearly flawed both in theory and in practice and the Company's use of an MSS in this proceeding suffers from many of the same commonly-recognized challenges with this cost allocation approach. I will offer alternative distribution plant allocators and discuss these in the following sections of my testimony addressing the Company's D3 and D4 allocators.

Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S D3 ALLOCATOR?

A. Yes. The D3 allocator used in the Company CCOSS allocates the primary demand portions of the Company's distribution plant. The Company states that its D3 allocator is based on each class' contribution to overall system average annual six-hour system distribution peak kW demand and is used to allocate distribution plant minus the 0.83 kw/customer included in the minimum system portion of the primary customer component.[49]

Q. DID YOU MAKE ANY CHANGES TO THE COMPANY'S D3 ALLOCATOR?

A. Yes, since I am recommending to not utilize the Company's MSS to allocate distribution plant, I have made an upward adjustment to its D3 allocator to account for the downward adjustment the Company states that it has made for MSS purposes. I have added an additional demand of 0.83kW/customer to the Company's D3 demands for each customer class.

Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S D4 ALLOCATOR?

[49] Direct Testimony of Gina Ice, Exhibit GSI-1, Schedule 2, p. 2.

A. Yes. The D4 is based on non-coincident kW demands at the secondary service level adjusted for the load carrying capacity included in the hypothetical minimum system. The Company adjusts its NCP demand at the secondary service level by subtracting the 3.0 kW/customer it states is "already included in the minimum system portion of the secondary customer component".[50]

Q. DID YOU MAKE ANY CHANGES TO THE COMPANY'S D4 ALLOCATOR?

A. Yes, since I have made an upward adjustment to its D4 allocator to account for the downward adjustment the Company states that it has made for MSS purposes. I have added an additional demand of 3.0kW/customer to the Company's D4 demands for each customer class.

Q. EXPLAIN HOW THESE DISTRIBUTION DEMAND ALLOCATION FACTORS RELATE TO DISTRIBUTION SYSTEM PLANNING.

A. The Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC Manual") notes that distribution system components such as substations, feeders, and transformers are typically defined in a fashion that ensures sufficient capacity is available to meet the local area loads. Demand measures such as an NCP, or other measures of individual customer maximum demands, are typically used to allocate these types of system costs. Higher-voltage electric systems, such as electric transmission systems, are designed to meet broader, less localized demands that are often measured by more diversified demand metrics such as a CP demand on a singular or an average basis.[51]

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[50] Direct Testimony of Gina Ice, Exhibit GSI-1, Schedule 2, p. 2.
[51] National Association of Regulatory Utility Commissioners ("NARUC"), Electric Utility Cost Allocation Manual, January 1992, pp. 96-98.

Q. PLEASE EXPLAIN YOUR PROPOSED METHOD OF ALLOCATING DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 368.

A. I recommend that the Commission reject the Company's use of a MSS method to classify distribution plant accounts 364 through 368. I recommend that the Commission: (1) reject the use of the MSS; (2) classify all primary and secondary distribution plant as being demand-related, and not customer-related, and (3) use an allocation of number of customers to allocate services plant. Further, I disagree with the Company's use of a CP-based method for allocating primary distribution plant. However, since the Company has not provided reliable demand data, workpapers, or back-up source documents in discovery requests, specifically asking for the Company's CP and NCP demand data at the substation, primary, and secondary distribution level, I have no choice but to use the Company's D3 allocation factor (as adjusted to remove the MSS downward adjustment).

Q. PLEASE EXPLAIN HOW YOU WOULD TYPICALLY PROPOSE TO ALLOCATE THE DEMAND RELATED PORTIONS OF DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 368.

A. Typically, I would propose to classify all primary and secondary distribution plant (excluding services, meters, and street lighting accounts) as being demand-related and allocate the demand related portion of the distribution plant using the following methods (1) allocate all primary distribution plant on a class NCP basis; (2) use a simple average of NCP and individual customer demands to allocate secondary distribution plant; and (3) use an allocation of number of customers to allocate services plant. However, the Company has not provided a sufficient level of detail or load data in responses to discovery in order for these allocation changes to be made. If the Company provides

further supplemental details and data in discovery or its testimony that can be used to appropriately derive alternative demand allocation factors I will supplement my testimony at that time.

Q. HOW DID YOU ALLOCATE DISTRIBUTION EXPENSES?

A. I have allocated distribution plant expenses as either primary demand or secondary demand. While not all of the costs associated with distribution expense accounts are demand related the Company's aggregation of FERC accounts in its CCOSS makes it difficult to make any necessary changes to the individual allocation of costs that should be classified and allocated as customer related.

Q. HOW WOULD YOU TYPICALLY ALLOCATE DISTRIBUTION EXPENSES?

A. Typically, distribution plant expenses should follow the same allocation approach or methodology used to allocate its Distribution Plant account counterpart.

Q. HAVE YOU FOUND ANY ADMINISTRATIVE OR FORMATTING ISSUES WITH THE COMPANY'S JCOSS AND CCOSS?

A. Yes, the Company's presents its costs and subsequent allocations in its JCOSS and CCOSS at a classification level of detail in which the Company aggregates the costs from various FERC accounts which it has identified to apply to that classification. The Company does not present a JCOSS or CCOSS that is broken down at the FERC account level with associated allocation factors. For instance, the Company's CCOSS presents distribution plant costs as Primary Demand, Secondary Demand, Primary Customer, Secondary Customer, Street lighting, Area Lighting, Meters, and Load management, however, each of these levels of classification only provide an aggregate of the costs from various FERC accounts in which the Company has assigned to these classifications.

Furthermore, I recommend that the Company not embed its CCOSS within the same excel spreadsheet tab as its JCOSS.

Q. PLEASE EXPLAIN WHY THE COMPANY'S FORMAT OF ITS JCOSS AND CCOSS AN ISSUE?

A. The Company's presentation of its JCOSS and CCOSS is not transparent and does not provide the level of detail necessary to fully comprehend and allocate costs to the various customer classes. The Company's current structure and format of its JCOSS and CCOSS make it difficult, time consuming, and in some instances nearly impossible to make changes to individual plant accounts or current allocation factors.

Q. WHAT ARE YOU RECOMMENDATIONS REGARDING THE STRUCTURE AND FORMAT OF THE COMPANY'S JCOSS AND CCOSS?

A. I recommend that in the Company's next rate case proceeding that the Company' file a transparent and comprehensive JCOSS and CCOSS which provides costs at the FERC account level and the associated allocation factor used to allocate the costs in each FERC account to its customer classes. Providing a JCOSS and CCOSS with the FERC account level of detail will provide transparency and simplicity in evaluating and employing any necessary changes or revisions in the Company's JCOSS and CCOSS.

E. CCOSS Recommendations

Q. PLEASE SUMMARIZE YOUR CCOSS RECOMMENDATIONS.

A. I recommend the Commission utilize a set of alternative CCOSS methodologies that includes: (1) a 12 coincident peak ("CP") methodology to allocate transmission plant costs; (2) a rejection of the Company's minimum system study for allocating distribution plant accounts 364-368; (3) a distribution plant allocation methodology that treats all plant

investment (accounts 364-368) as being demand and not customer related; and (4) a methodology that uses customer counts to allocate services-related plant. Furthermore, my review of the Company's CCOSS was significantly impaired by a lack of transparency and support documentation mapping cost of service allocators, and other crucial input data to FERC accounts. Therefore, I recommend that the Commission order the Company, in its next rate case, to file a transparent and comprehensive CCOSS that documents and maps costs and allocators at the FERC account level to each of its customer classes.

Q. DO YOUR CCOSS RECOMMENDATIONS CHANGE THE CLASS RATES OF RETURN?

A. Yes. I have identified those changed class rates of return and compared them to the Company's original CCOSS results in Exhibit DED-2. Using my recommended allocation factors, I have also prepared an alternative CCOSS which is attached to this testimony as Exhibit DED-3. In addition, I have prepared Exhibit DED-4 which shows the results of the Company's CCOSS.

IV. Marginal Cost Of Service Study

A. Introduction

Q. WHAT IS THE PURPOSE OF A MARGINAL COST OF SERVICE STUDY?

A. A marginal class cost of service study ("MCCOSS") seeks to estimate changes in cost relative to changes in output, not a fixed level of output, where outputs are usually defined as energy sales, peak demand, number of customers, or various combinations of each. This differs from an embedded (or "fully-allocated") CCOSS which seeks to determine the allocation of costs across customer classes for a fixed period of time and

across a fixed measure of output (often referred to as "billing determinants"). Further, while an embedded CCOSS can be viewed as an examination of historical cost of service, a MCCOSS can, in theory, tend to be more forward-looking in its estimation of cost of service. In addition, while an embedded CCOSS can be thought of as a more static short-term analysis of average costs, a MCCOSS is generally thought of as reflecting longer-run incremental costs of providing service. While disagreements surrounding the review of an embedded CCOSS often focus on cost allocations, disagreements associated with the review of a MCCOSS often tend to center around the development of drivers used to estimate these forward looking, incremental costs.

Q. HOW DO RESULTS OF AN MCCOSS COMPARE TO A UTILITY'S EXISTING EMBEDDED COST?

A. Very little, since a MCCOSS is typically designed to estimate longer-run, forward-looking incremental costs, not historic costs for a fixed period of time. Any similarities between the results of an embedded CCOSS and a MCCOSS are likely to be only coincidental. Given these differences, it is important that the revenue responsibility of a MCCOSS be reconciled with the revenue responsibility results of an embedded CCOSS so that final rates can be set in a fashion that allows the Company an opportunity to recover a return on and of its existing embedded plant investment.

Q. HOW ARE THE RESULTS OF AN EMBEDDED CCOSS USUALLY RECONCILED WITH THE RESULTS OF A MCCOSS?

A. The NARUC Electric Cost Allocation Manual identifies a number of different methods of reconciling marginal cost revenue responsibilities with existing revenue

requirements.[52] These reconciliation methods can include such approaches as "Ramsey pricing," a method that allocates differences between marginal and embedded costs based on the inverse of a rate class' estimated price elasticity of demand.[53] However, the simplest method of reconciliation is to scale all rate classes' marginal costs to embedded costs in equal proportions (also known as an "equi-proportional" method).[54] For instance, if the Company's total marginal cost revenue responsibilities suggest a total revenue collection of $250 million, while the results from its embedded CCOSS suggest a $320 million revenue requirement, class-specific marginal cost results would be scaled equally by a factor of 128 percent (i.e., $320/$250) to obtain results comparable to existing revenue requirements.

Q. HOW DOES THE COMPANY UTILIZE ITS MCCOSS?

A. First, it is important to distinguish between "customer classes" on the one hand, and "rate schedules" on the other hand, in understanding the use and importance of the Company's MCCOSS. "Customer classes" can be thought of as broad classes of customer types such as residential, general service, outdoor lighting, among others. "Rate schedules" define the specific customer service offerings (or tariffs) within a customer class. For instance, the outdoor lighting "customer class" has two different "rate schedules" that include the Lighting Energy Only and the Area Lighting service offerings. The Company's MCCOSS is used to assign revenue responsibilities within broad "customer classes" to specific "rate schedules." The MCCOSS is not used to allocate

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[52] *See* Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, p. 149.
[53] *See* Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, pp. 155-156.
[54] *See* Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, pp. 160.

revenue responsibilities across these broad rate classes (i.e., residential, general service, outdoor lighting, etc.) but within them. Customer class-specific revenue responsibilities are set by the Company's (embedded) CCOSS results.[55] In other words, the Company uses the results of its embedded CCOSS, and its respective gradualism adjustments, to allocate costs to "residential customers." The MCCOSS is then used to assign the residential rate class' revenue responsibilities between the Residential Service and Residential Demand Control rate schedules.

Q. PLEASE EXPLAIN HOW THE MCCOSS ALLOCATES REVENUE RESPONSIBILITIES WITHIN A GIVEN CUSTOMER CLASS.

A. The Company uses what it refers so as an "equal percentage of marginal costs" ("EPMC") methodology. Under the EPMC method, a rate schedule's revenue responsibility is equal to its class-specific pro-rata share of the Company's estimated marginal cost.[56] So, if the Residential Service rate schedule is estimated to equal 85 percent of the residential rate class' MCCOSS revenues, then the Residential Service rate schedule will receive 85 percent of the total residential class revenue responsibility generated by the embedded CCOSS.

Q. IS THE COMPANY CONSISTENT IN HOW IT USES THIS MCCOSS ALLOCATION METHODOLOGY?

A. No, since the Company allocates rate class revenues using three modified versions of the EPMC methodology. The Company claims that each method mitigates the abruptness of the rate increases that would result from a strict application to EPMC

[55] Direct Testimony of David G. Prazak at 3:9-12.
[56] Direct Testimony of David G. Prazak at 8:5-9.

methodology.[57] I will discuss this potential inconsistency later in this section of my testimony.

Q. DOES THE COMPANY USE ITS MCCOSS FOR ANYTHING OTHER THAN ASSIGNING RATE CLASS REVENUE RESPONSIBILITIES?

A Yes. The Company also utilizes its MCCOSS results in its proposed rate design, primarily in how it proposes to set individual rate components (i.e., customer charges, volumetric energy charges, etc.). The Company explicitly compares its proposed customer charges for each rate class to its calculated marginal customer-related costs for each rate class. For most rate classes, the proposed customer charge is equal or almost equal to the calculated marginal customer-related cost.[58] However, volumetric energy charges rarely match the MCCOSS results. I will discuss the inconsistencies in how the Company uses its MCCOSS results for rate design purposes in the rate design section of my testimony.

B. MCCOSS Methodology

Q. PLEASE DESCRIBE THE PROCESS USED BY THE COMPANY IN ESTIMATING ITS MCCOSS.

A. The Company estimates marginal costs in five functional areas that include generation, transmission, ancillary services, distribution, and customer costs. The marginal annualized cost is estimated by adjusting the investment per unit by a general plant loading factor. The resulting figures are multiplied by an annual economic carrying charge percentage, and a plant-related administrative and general ("A&G") loading factor,

[57] Direct Testimony of David G. Prazak at 9:11 to 10:12.
[58] Direct Testimony of David G. Prazak, Table 4.

that results in an annualized plant cost estimate. Finally, operations and maintenance ("O&M") and non-plant related A&G expenses, as well as revenue requirements for working capital, are added to obtain the final annualized costs.[59]

Q. HOW DID THE COMPANY ESTIMATE ITS MARGINAL ENERGY COSTS FOR THE 2018-2022 TIME PERIOD?

A. The Company began its estimation of marginal energy costs with MISO's forward monthly peak and off-peak prices measured at the OTP node for the period January 2018 through December 2022. The Company then used historical hourly data of the price difference between the Indiana node and the OTP node to develop forward prices and shaped the monthly energy peak and off-peak forward prices at the OTP node using historical monthly averages of day-ahead hourly market prices for the period May 1, 2014 to July 31, 2017 and averaged the resulting prices by costing period. Finally, these market prices were adjusted for the working capital costs and marginal energy losses.[60]

Q. HOW DID THE COMPANY ESTIMATE ITS MARGINAL GENERATION CAPACITY COSTS FOR THE 2018-2022 TIME PERIOD?

A. The Company's marginal generation capacity costs are estimated using the forecast annual capacity price, the Planning Reserve Margin ("PRM") calculated by MISO in its Loss of Load Expectation ("LOLE") study, and the probability that each hour is MISO's system annual peak hour. The Company's marginal generation capacity costs were developed using the installed capacity PRM percentages, and the costs were then adjusted for marginal system losses and working capital requirements.[61]

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[59] Direct Testimony of David G. Prazak, Schedule 2, pp. 4-13.
[60] Direct Testimony of David G. Prazak, Schedule 2, pp. 5-6.
[61] Direct Testimony of David G. Prazak, Schedule 2, pp. 6-7.

Q. HOW DID THE COMPANY ESTIMATE ITS MARGINAL TRANSMISSION COSTS FOR THE 2018-2022 TIME PERIOD?

A. The Company's marginal transmission costs were estimated in two distinct categories: the Network Integration Transmission Service ("NITS") rate for transmission facilities at or below 100 kV in the Company's Control Area, and the Network Upgrade Charge ("NUC") rate for transmission facilities above 100kV.[62]

Q. HOW DID THE COMPANY ESTIMATE ITS NITS RATE FOR THE 2018-2022 TIME PERIOD?

A. The Company began its estimation with its NITS rate for 2017. The Company then forecasts the projected annual increase in its NITS revenue requirement associated with its new 115 kV (below $5 million), 41.6 kV, and 69 kV projects expected to come into service in the 2018-2022 period, while excluding the projects that qualify for the Company's transmission cost rider. The Company then added MISO's estimated annual carrying charges and divided by the forecast of 12 monthly OTP-control-area coincident peaks to compute the annual per-kW NITS charge.[63]

Q. HOW DID THE COMPANY ESTIMATE ITS NUC RATE FOR THE 2018-2022 TIME PERIOD?

A. The Company relied on MISO's projected annual revenue requirement to estimate its NUC rate. The Company's NUC transmission revenue requirement is the sum of MISO's system-wide allocation, sub-regional allocation, and individual allocations corresponding to new projects. MISO's projected annual incremental transmission

[62] Direct Testimony of David G. Prazak, Schedule 2, p. 7.
[63] Direct Testimony of David G. Prazak, Schedule 2, p. 8.

revenue requirements were divided by the expected 12 monthly coincident peak forecast in each year used, and the total dollar revenue requirement amount was then divided by the sum of 12 CPs in the OTP zone.[64]

Q. DID THE COMPANY TAKE ANY ADDITIONAL STEPS TO ESTIMATE ITS MARGINAL TRANSMISSION COSTS?

A. Yes. The Company allocated the monthly transmission cost to hours using the probability of a given hour's being the monthly peaks, with probabilities calculated using four years of the OTP Control Area's historical hourly loads. Finally, the costs were adjusted by losses and working capital requirements.[65]

Q. HOW DID THE COMPANY ESTIMATE ITS MARGINAL ANCILLARY SERVICES COSTS FOR THE 2018-2022 TIME PERIOD?

A. The Company estimated its ancillary services costs for the 2018-2022-time period by simply adjusting its 2016 ancillary services costs for inflation, losses, and working capital requirements.[66]

Q. HOW DID THE COMPANY ESTIMATE ITS MARGINAL DISTRIBUTION SUBSTATION AND TRUNKLINE FEEDER COSTS FOR THE 2018-2022 TIME PERIOD?

A. The Company divided its budgeted growth-related investment by the estimated addition to distribution substation non-coincident peak demand over the same period. The Company then added distribution O&M expenses plus an allocated portion of

[64] Direct Testimony of David G. Prazak, Schedule 2, p. 8-9.
[65] Direct Testimony of David G. Prazak, Schedule 2, p. 9.
[66] Direct Testimony of David G. Prazak, Schedule 2, p. 9.

overhead expenses divided by the sum of non-coincident peak demands at the substations.[67]

Q. HOW DID THE COMPANY DETERMINE ITS DISTRIBUTION O&M COSTS FOR THE 2018-2022 TIME PERIOD?

A. The Company states that it allocated its distribution O&M expenses by FERC account for 2012-2016 annual distribution stations O&M expenses including associated overheads and divided this amount by the sum of NCP demands at the substation and converted to 2018 dollars.[68] However, upon review the Company decided to use the average of 2014-2016 values of its distribution O&M expenses as "a reasonable proxy" for its O&M substation expenses.[69]

Q. HOW DID THE COMPANY ESTIMATE ITS MARGINAL LOCAL DISTRIBUTION FACILITIES COSTS FOR THE 2018-2022 TIME PERIOD?

A. The Company used its own estimates of the typical investment in local distribution facilities for various types and sizes of customers and expressed these investments as a fixed monthly cost per kW of design demand, which the Company estimated by dividing transformer capacity by the number of customers served by the transformer. Finally, the Company again used 2014-2016 as the basis for its "estimate" of distribution facility O&M expenses rather than attempting to forecast these costs.[70]

Q. HOW DID THE COMPANY ESTIMATE ITS MARGINAL CUSTOMER COSTS FOR THE 2018-2022 TIME PERIOD?

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[67] Direct Testimony of David G. Prazak, Schedule 2, p. 10.
[68] Direct Testimony of David G. Prazak, Schedule 2, p. 10.
[69] Direct Testimony of David G. Prazak, Schedule 2, p. 10.
[70] Direct Testimony of David G. Prazak, Schedule 2, p. 11.

A. The Company used its "current installed cost of a typical meter, including current transformer if applicable, and service drop for customer categories,"[71] as well as associated labor expenses, which were taken from average expense data for 2015 and 2016 and adjusted for inflation. Similarly, the customer accounts expenses were also averaged for 2015 and 2016 and adjusted for inflation. However, the Company used expense data from 2014 as well as 2015 and 2016 when calculating its customer service and informational expenses.[72] Finally, the Company calculated a typical one-time cost of interconnecting a small power producer, as costs associated with small power producer interconnections are shared by all customers.[73]

Q. PLEASE DESCRIBE HOW THE COMPANY USED THESE ESTIMATED MARGINAL COSTS TO ESTIMATE THE FINAL ANNUAL MARGINAL COSTS.

A. The Company applied loading factors to its marginal cost estimates to capture the additional plant, O&M expenses, or overhead costs incurred when electric plant or electric O&M increase. In addition, the Company calculated economic carrying charges to capture elements of OTP's revenue requirement associated with marginal investment in certain categories of distribution plant. Finally, marginal capacity losses were applied to distribution substation and trunkline feeder costs to account for system losses using peak demand loss factors from the Company's 2010 loss study and then loss-adjusted costs were time-differentiated.[74]

Q. HOW DID THE COMPANY CALCULATE ITS LOADING FACTORS?

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[71] Direct Testimony of David G. Prazak, Schedule 2, p. 12.
[72] Direct Testimony of David G. Prazak, Schedule 2, p. 12.
[73] Direct Testimony of David G. Prazak, Schedule 2, p. 13.
[74] Direct Testimony of David G. Prazak, Schedule 2, p. 13.

A. The Company calculated its non-plant-related A&G loader as the average ratio of non-plant-related A&G expenses to O&M expenses over the period 1982-2014. The Company calculated its plant-related A&G loader by regressing its maintenance of general plant expenses on cumulative net additions to its total electric plant from 1982-2014, and then adding its average property and terrorism insurance rate for distribution plant requiring insurance. Finally, a general plant loader was estimated by regressing cumulative net additions to general plant on cumulative net additions to total plant less general plant from 1996-2014.[75]

Q. HOW DID THE COMPANY CALCULATE ITS ECONOMIC CARRYING CHARGES?

A. The Company calculated its annual carrying charge as a function of the Company's incremental cost of capital, expected inflation rate, average service life and patterns of failure for the type of plant in question.[76]

Q. HOW DID THE COMPANY APPLY THE RESULTS OF ITS MCCOSS TO DETERMINE RATE SCHEDULE REVENUE REQUIREMENTS?

A. As mentioned earlier in this section of my testimony, the Company applied three variations of the EPMC method to allocate the customer class revenue responsibilities to the individual rate schedules. The first method was applied to the Large General Service, Irrigation, Controlled Service Interruptible, and Controlled Service Deferred customer classes.[77] This method simply assigns each rate schedule a percentage increase equal to the average of the EMPC percentage increase and the customer class percentage

[75] Direct Testimony of David G. Prazak, Schedule 2, p. 14.
[76] Direct Testimony of David G. Prazak, Schedule 2, p. 14-15.
[77] Direct Testimony of David G. Prazak, Schedule 4.

increase as determined by the CCOSS study.[78] The second method was applied to the Residential and General Service customer classes.[79] This method assigns each rate schedule a percentage increase equal to the average of the percentage increase from the first method and the customer class percentage increase as calculated from the CCOSS.[80] The third method was applied only to the lighting class.[81] According to the Company, this method "utilizes additional analysis and knowledge of the rate itself to minimize the impact of the rate change to the customer group."[82] The Company stated that the exact calculations are the same as method one and two, after which the "iterative method that uses a blended variation between the two rate classes" is applied. [redacted]

Q. HOW DID THE COMPANY ALLOCATE REVENUES FOR THE REMAINING CUSTOMER CLASSES?

[78] Company's response to data request ND-PSC 11.23.
[79] Direct Testimony of David G. Prazak, Schedule 4.
[80] Company's response to data request ND-PSC 11.23.
[81] Direct Testimony of David G. Prazak, Schedule 4.
[82] Company's response to data request ND-PSC 11.23.
[83] Company's response to data request ND-PSC 14.01, Attachment 4.

A. Customer classes with only one rate schedule were assigned the percentage increase calculated using the Company's CCOSS.[84] The Company also used this method for the Other Public Authorities customer class because the majority of the class's revenues came from a single rate schedule.[85]

Q. DO YOU AGREE WITH THE RESULTS OF THE COMPANY'S MARGINAL COST OF SERVICE STUDY?

A. No. The Company's MCCOSS suffers from a number of shortcomings that include:

- Its failure to provide any considerable insights into the Company's true marginal cost of service.
- The inconsistent and inappropriate use of historical data as a proxy for future costs when estimating O&M expenses.

C. The Company's MCCOSS Provides Little Insight Into The Company's True Marginal Cost Of Service

Q. IS THE COMPANY'S MCCOSS A TRUE MARGINAL COST STUDY?

A. No, a large part of the analysis is based upon costs that are either (a) "average," not "marginal" in nature or (b) simple inflation-based extrapolations of costs, not true incremental costs estimated over a range of output for any given output measure.

Q. EXPLAIN HOW THE COMPANY'S MARGINAL COST ANALYSIS IS MORE AVERAGE THAN MARGINAL IN NATURE.

[84] Direct Testimony of David G. Prazak, Schedule 4.
[85] Direct Testimony of David G. Prazak at 11:3-6.

A. The underlying data utilized by the Company in estimating its MCCOSS are based in part upon historic average cost information. For instance, to estimate marginal O&M costs associated with meter and service-related customer costs, the Company simply estimates the average O&M expense per weighted customer for 2015 and 2016 and adjusts this estimate for inflation. However, it is important to note that the Company's O&M costs have declined in all but one year over the period from 2012-2016, so if the Company would have projected these costs based upon its reported trend, rather than using a historical average with a fixed inflation factor, these marginal O&M expenses would have most likely been lower .[86]

Q. IS THE USE OF "AVERAGE" DATA TO DETERMINE "MARGINAL" COSTS A PROBLEM UNIQUE TO THIS FILING?

A. No. The NARUC Electric Cost Allocation Manual notes that many marginal costing methodologies used by utilities are based upon information that is often more average in nature than it is marginal. Ironically, many utility marginal costs studies often rely on embedded (average book) costs that are in some way or another, part of the embedded CCOSS and do not differentiate themselves in any meaningful nor insightful manner. [87]

D. The Company's Use Of Historical Information Within Its MCCOSS Is Flawed

Q. PLEASE EXPLAIN HOW THE COMPANY CALCULATES NEW DISTRIBUTION FACILITIES INVESTMENT COSTS.

A. The Company's distribution facilities cost estimate simply escalates its current average distribution investment per kW by an annual inflation rate of three percent.

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[86] 42 Vol 2b DGP-1 Schedule 2 2018 Marginal Cost Study

[87] Electric Utility Cost Allocation Manual (January 1992), National Association of Regulatory Utility Commissioners, p. 127; citing J.W. Wilson, Report for the Rhode Island Division of Public Utilities, Public Utilities Commission and Governor's Energy Office (1978), pp. B-27-8.

Q. IS THIS ESTIMATE TRULY MARGINAL IN NATURE?

A. No, and the Company's methodology here, as well as in other parts of its analyses, are clearly faulty from a marginal cost perspective since the methods are simply an extrapolation of embedded costs. This estimate is calculated using distribution facilities investment costs based upon a 2015 total company-based estimate that was filed in its last Minnesota rate case.[88]

Q. PLEASE EXPLAIN WHY A SIMPLE INFLATION ADJUSTMENT IS NOT THE SAME AS A "PROJECTION."

A. Adjusting current costs for inflation is not a "forecast"; rather it is a numeric transformation of historic data based upon a fixed number. For instance, to multiply a known average cost by inflation assumes that the cost reported today is the same as the cost tomorrow, adjusted for inflation and that there are no other differences with regards to the underlying costs themselves, or, more importantly, the scale at which those costs have been estimated. Marginal costs are calculated as the change in costs given a change in output. Taking an average cost and multiplying by an inflation factor is simply inconsistent with the economic definition of a forward-looking, long-run marginal cost.

E. Recommendations

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S MCCOSS?

A. I recommend that the Commission reject the Company's MCCOSS. The Company's MCCOSS is flawed and the Company's application of the MCCOSS results are subjective and arbitrary. I recommend that rate schedule revenue responsibilities be

[88] Company's response to data request ND-PSC-8.05.

set upon the results of my alternative CCOSS and my proposed revenue distribution. Furthermore, the Company's use of the MCCOSS as a basis for its proposed customer charge increases is faulty and, if accepted, would result in substantially large increases for many customer classes.

V. Revenue Distribution and Rate Design

A. Company Proposed Revenue Distribution

Q. PLEASE EXPLAIN THE PROCESS BY WHICH CLASS REVENUE RESPONSIBILITIES ARE DETERMINED.

A. The revenue distribution process is typically an attempt to reconcile the strict, class-specific results of an embedded CCOSS with many of the rate design policy goals discussed earlier. For instance, the CCOSS may indicate one, or several classes' revenue responsibility is far in excess of the proposed overall average increase in rates. In other words, the strict results of the CCOSS may show that a particular class may warrant a very large increase in rates in order to bring revenues closer to that class' estimated full cost of service. This significant percent increase in rates, however, may violate rate gradualism policies. Thus, some intermediate step needs to be conducted that uses the CCOSS to "inform" policy as to the direction of the rate change, but conditions that change to conform to other ratemaking policy goals. This intermediate step is typically done in the revenue distribution process. The revenue distribution process, in turn, often uses a variety of subjective "rules" (or formulaic approaches) to allocate class revenue increases in a fashion that moves rates closer to costs, but conditions those increases to minimize rate shock and ensure policy equity.

Q. HOW DID THE COMMISSION DISTRIBUTE THE REVENUE INCREASE IN THE LAST CASE?

A. The Company's last rate case resulted in a Settlement Agreement which was approved by the Commission.[89] In the Company's last rate proceeding, all classes received a revenue increase except the large general service ("LGS") rate class.[90] Although there is no explicit discussion regarding how the rates and charges were determined it appears that the rate increase was applied to both customer charges and energy charges, as well as demand charges, where applicable.[91]

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED REVENUE DISTRIBUTION IN THIS PROCEEDING.

A. The Company states that it used the results of its embedded CCOSS as "the primary guide for setting the class revenue responsibilities".[92] The Company's proposed class revenue increases that range from a low of 8.26 percent to a high of 19.0 percent relative to an overall proposed system increase of 10.61 percent. The Company notes that it has used its "judgement"[93] in proposing class-specific revenue responsibilities with the goal of moving all customer classes closer to its CCOSS-indicated cost responsibilities.[94]

Q. COULD THE PROPOSED REVENUE DISTRIBUTION BE INFLUENCED IN ANY WAY BY RECENT FEDERAL INCOME TAX REFORM LEGISLATION?

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[89] Case No. PU-08-862, Otter Tail Corporation Electric Rate Increase Application, Order on Settlement, November 25, 2009.
[90] Case No. PU-08-862, Otter Tail Corporation Electric Rate Increase Application, Order on Settlement, November 25, 2009, Amended Settlement Agreement, p. 9.
[91] Case No. PU-08-862, Otter Tail Corporation Electric Rate Increase Application, Order on Settlement, November 25, 2009, Amended Settlement Agreement, pp. 10-11.
[92] Direct Testimony of Gina Ice, 11:8.
[93] Company's response to ND-PSC-09.6
[94] Company's response to ND-PSC-09.6

A. Yes. These revenue distribution proposals could be impacted by federal income tax legislation. The Company has filed supplemental testimony to adjust its revenue requirement to account for the recently passed federal tax reform legislation, but has not provided any updated rate design exhibits or workpapers to reflect these revenue requirement reductions.

Q. PLEASE EXPLAIN WHAT IS MEANT BY A "RELATIVE RATE OF RETURN."

A. A "relative rate of return" ("RROR") is simply the ratio of a given class' estimated rate of return to the overall system rate of return. This ratio can also be thought of as a "unitized" rate of return since each class' estimate return is standardized to the Company's overall request. For example, if the residential class is estimated to be earning 11 percent from the CCOSS, and if the Company is requesting a 10 percent overall rate of return, then the residential class can be said to have a RROR of 1.10 (i.e., 11 percent divided by 10 percent). RRORs can also be thought of as a special type of index number measuring a specific class' return relative to the Company's overall rate of return. Thus, classes with a relative rate of return greater than 1.0 entails that those classes are likely earning an amount greater than the Company's overall rate of return. Those classes with a relative return below 1.0 can be said to be earning an amount less than the Company's overall rate of return. Exhibit DED-5 presents the Company's estimated class relative rates of return under its current and proposed rates.

Q. DO YOU AGREE THAT A CLASS RROR LESS THAN 1.0 IS PROBLEMATIC OR INEQUITABLE?

A. Not necessarily. Consistent with the principles identified above, there may be policy reasons to support such a result that do not result in inequitable cross-

subsidization. For example, the presence and/or continuation of a RROR below one could be the result of a prior agreed-upon rate freeze that prevents class rates from increasing to correct the revenue deficiency (relative to cost of service). In this example, the presence of a below one RROR is simply a function of a prior policy decision, not necessarily the result of some arbitrary or intentionally-designed inequity. Therefore, I do not agree that cross subsidization automatically means that such subsidization is problematic or inequitable.

Q. HAVE YOU PREPARED A COMPARISON OF THE RROR IN THE LAST RATE PROCEEDING RELATIVE TO THE COMPANY'S ESTIMATES IN THIS PROCEEDING?

A. Yes. Exhibit DED-6 provides a comparison of the RRORs from the 2008 rate case and those filed in this proceeding. The residential class RRORs has remained relatively the same as that filed in the Company's last rate case increasing slightly from 0.51 to 0.52. The general service ("GS") and large general service classes are both earning RRORs lower than the prior rate case.

Q. WHAT ARE YOUR REVENUE DISTRIBUTION RECOMMENDATIONS?

A. I recommend a two-step revenue distribution methodology. In the first step, each of the under-earning classes is assigned an increase that is 1.25 times the system average increase. In the second step, the residual revenue deficiency between the target rate of return and the first step revenue increase is allocated to the remaining classes in relation to their current test year revenues. My recommended revenue distribution gradually moves each of the under-earning classes to a RROR of 1.0. Under my proposed approach, residential classes receive 31 percent of the Company's proposed

total rate increase, an increase that is lower than the Company's proposal to allocate about 42 percent of its requested increase to the residential classes. The primary difference in the two approaches is that my approach tempers the overall increase by assigning part of the proposed rate increase to over-earning classes. The results of my recommended revenue distribution using the Company's revenue requirement provided in its direct testimony are shown on Exhibit DED-7 and DED-8 provides the Company's current and proposed rates compared to my recommended alternative rates.

B. Rate Design Overview

Q. WHAT ARE SOME OF THE GUIDING CRITERIA OR PRINCIPLES UPON WHICH RATE DESIGN SHOULD BE BASED?

A. There are several generally accepted rate design principles used in utility regulation that include:

1) Rates should be fair, just, and reasonable, and not unduly discriminatory.

2) To the extent possible, gradualism should be used in order to protect customers from rate shock.

3) Rate continuity should be maintained whenever possible.

4) Rates should be informed by costs, however, in some instances class cost of service results may not be the only factor used in rate development.

5) Rates should be transparent and comprehensible to customers.

Q. HOW ARE THE ABOVE CRITERIA BLENDED TO DEVELOP RATES FOR A REGULATED UTILITY?

A. It is important to consider all of the principles I mentioned above. However, any principle's relative weight can change depending upon the importance of certain policy

goals. Rate design should strike a balance between policy goals and result in rates that are fair, just, and reasonable. There is no pre-set or universally-accepted formula for developing rates and, as a result, judgment is necessary to formulate a rate design that meets these objectives.

Q. HOW DOES THE COMPANY CHARACTERIZE ITS RATE DESIGN OBJECTIVES?

A. The Company states that it has the following rate design objectives:

- The rate design should give OTP a reasonable opportunity to achieve its revenue requirement with rate structures that follow OTP's marginal cost structure, thereby allowing revenues to track costs.
- The rate design should promote efficient use of resources by giving consumers price signals that reflect marginal costs, including seasonal differences and, where reasonably possible, time-of-day ("TOD") differences.
- Rate design changes should be gradual to avoid sudden bill impacts.
- The rate design should be based on structures that are reasonable and nondiscriminatory. Including minimizing cross-subsidies within rate classes to the extent reasonably possible.
- The rate design should result in rates that are administratively feasible and avoid unnecessary complexity that might confuse customers.
- The rate design should preserve the attractiveness of load control/interruptible riders as those riders provide substantial benefits to all OTP customers.[95]

[95] Direct Testimony of David G. Prazak, 2:7-23.

Q. DO YOU AGREE WITH HOW THE COMPANY HAS ATTEMPTED TO RECONCILE ITS PROPOSED RATE DESIGN WITH THESE GOALS?

A. No. Rate design should strike a fair balance between policy goals and result in rates that are fair, just, and reasonable. The Company's proposed rate design, in addition to being inconsistent with several of its purported objectives, fails in striking a balance between these various goals. The Company's rate design proposals are subjective in their use of MCCOSS results and appear to completely ignore the principles of gradualism and the avoidance of rate shock.

Q. HOW SHOULD POLICY BALANCE RATE DESIGN GOALS IN SETTING CUSTOMER CHARGES AND VOLUMETRIC RATES?

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by a form of pricing referred to as a "two-part tariff," sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

Q. WHAT IS THE APPROPRIATE ROLE OF COSTS IN SETTING RATES BASED UPON A TWO-PART TARIFF?

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs do not need to serve as the sole or exclusive basis for rates in order for them to be set optimally (*i.e.,* fixed charges do not need to strictly equal fixed costs, variable rates

need not strictly equal variable costs). Unfortunately, the "fixed charge-equals-fixed cost" philosophy gets repeated so often that it can often drown out meaningful discussions about other equally important consideration in setting rates in imperfect markets. In fact, appropriate rate setting in the context of a two-part tariff typically has more to do with consumer demand than it does with cost.

Q. IF COST CONSIDERATIONS WERE INCORPORATED INTO THE ANALYSIS, WHAT TYPE OF COSTS SHOULD BE EXAMINED?

A. Marginal costs are the more appropriate costs to be examined in this instance, not average costs. There are also a variety of short-run and long-run considerations that should be factored into this analysis. All too often, the purported cost-supporting arguments for certain rate structures places overwhelming emphasis on short-run static considerations and not longer-run dynamic ones.

Q. HASN'T THE COMPANY UTILIZED A DYNAMIC LONG-RUN MARGINAL COST STUDY IN DESIGNING ITS PROPOSED RATES?

A. No. While the Company has utilized what it refers to as a marginal cost study in formulating its rate design proposals, that study, as I noted earlier, suffers from a number of important deficiencies that question the marginal nature, as well as the accuracy, of its results. The Commission should discount the results of this marginal cost study as justification for the Company's purported "cost-based" rate proposals.

Q. HOW SHOULD FIXED AND VARIABLE CHARGES BE DETERMINED IN AN OPTIMAL TWO-PART TARIFF?

A. A challenge in determining appropriate rates for natural monopolies rests with setting the appropriate balance between fixed and variable charges subject to a regulated

firm's budget constraint (i.e., its allowed return on and of its investment). As I noted before, marginal costs can be a starting point for establishing variable rates. Mark-ups (or discounts) relative to these marginal costs should then be examined in order to determine an optimal means of transferring consumer surplus to the regulated utility, provided that consumer welfare is maximized. In other words, we can examine a variety of pricing strategies that use different fixed-variable price combinations so long as we do not: (1) price these so high we cause customer harm; (2) set price combinations that drive consumers out of the market (i.e., inefficient bypass, fuel switching, or deprivation of service); and (3) set prices which prevent a utility from meeting its budget constraint (i.e., fixed cost recovery).

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED RATE DESIGN.

A. The Company is proposing a number of changes to rates in this proceeding, the most significant of which are the substantial increases being proposed for various classes' customer charges. The Company justifies these large customer charge increases on the proposition that "aligning fixed charges with marginal costs promotes fairness among customers and encourages the efficient use of resources."[96] A summary of the Company's current and proposed customer charges is provided in Exhibit DED-9.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED RATE DESIGN CHANGES?

A. No, I do not agree with the Company's proposed rate design changes in this proceeding. The Company uses a faulty MCCOSS as the basis in setting its proposed rates for the various rate classes. Not only does this study suffer from a number of

[96] Direct Testimony of David G. Prazak, 15:4-5.

analytic faults, but the Company has subjectively and inconsistently used the results of the MCCOSS in proposing rates for various different classes. In some instances, the Company proposes strict adherence to the MCCOSS results, in other instances, even within the same rate schedule, the Company deviates from the strict us of its MCCOSS. I will discuss this in more detail, and provide several examples, in the following section of my testimony. Later in this section of my testimony, I will delve into the Company's rate schedule-specific proposals, but first, I will discuss, from a conceptual basis, the overarching deficiencies associated with the Company's rate design proposals.

C. Rate Design Deficiencies

Q. PLEASE DISCUSS SOME OF THE OVER-ARCHING DEFICIENCIES ASSOCIATED WITH THE COMPANY'S PROPOSED RATE DESIGN.

A. The Company's proposed rate design suffers from a number of over-arching deficiencies that are common across most, if not all of its rate design proposals. These deficiencies include:

- Customer charge proposals that are entirely out of line and inconsistent with its purported rate continuity/gradualism goals.
- Customer charge proposals that will impede the promotion of energy efficiency and distributed energy.
- Customer charge and rate design proposals that have regressivity implications.
- Rate design proposals that are inconsistent and arbitrarily tied to the Company's MCCOSS.
- Rate design proposals that will have considerable intra-class rate continuity issues.

I will discuss each of these issues in more detail in the following sub-sections of my testimony.

a. Customer charge proposals are inconsistent with rate continuity

Q. WHAT IS RATE CONTINUITY?

A. Rate continuity is a term used to describe a rate or set of rates that are similar in structure and magnitude from rate case to rate case. Rate continuity is generally an important objective in the rate design process in order to ensure that customers are not unduly burdened or confused from changes in their utility rates and charges.

Q. DOES THE COMPANY'S PROPOSED RATE DESIGN MAINTAIN RATE CONTINUITY?

A. No. The Company is proposing a number of revisions to both the rate structures and tariff terms of many of its rate classes. These changes in many instances include significant increases in the customer charges, removal of declining rate blocks, increases in demand charges, and changes to facilities charges including how those charges are applied (i.e. fixed charge or per kW).

Q. WHY IS IT PARTICULARLY IMPORTANT TO MAINTAIN RATE CONTINUITY IN THE CURRENT PROCEEDING?

A. The Company has not had a rate case since 2008. Since that time, it is highly likely that ratepayers have become accustom to a relatively stable set of electric rates since they have not changed in close to a decade. This familiarity and consistency has allowed customers to financially plan for and anticipate monthly bills for nearly a decade. However, the Company is now proposing to make significant changes that in some

instances could potentially cause a financial burden or rate shock and confusion to customers.

Q. ARE THE COMPANY'S PROPOSED CUSTOMER CHARGES, IN PARTICULAR, CONSISTENT WITH RATE CONTINUITY GOALS?

A No. The Company is proposing very large increases in customer charges for some customer classes. For instance, the Company is proposing a 90 percent increase in residential customer charges in this proceeding. Small commercial charges are proposed to increase by 92 percent, while increases in farm and irrigation customer charges are proposed to increase by 45 percent and 2,430 percent or 486 percent (depending on the option taken), respectively. These large percent increases are simply not in keeping with rate designs that follow rate continuity and gradualism principles.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING RATE CONTINUITY?

A. While in some instances changes in rate structures and tariff terms may be necessary, generally, these changes should be made on a gradual basis and with a clear objective to be achieved over time. Gradual changes to rates and charges allows the customer to adjust to changes in their monthly bills and become familiar with the price signals associated with the new rates and charges over a longer period of time. I will offer a number of alternatives to the Company's rate design later in my testimony. In many instances, I recommend more gradual increases in charges and rates in way that should result in less rate shock than the Company's proposals.

b. Customer charge proposals are inconsistent with the promotion of energy efficiency and distributed generation.

Q. IS THE COMPANY'S PROPOSED RATE DESIGN, SPECIFICALLY THE PROPOSAL TO SIGNIFICANTLY INCREASE THE CUSTOMER CHARGE, CONSISTENT WITH THE PROMOTION OF ENERGY EFFICIENCY AND CONSERVATION?

A. No, the Company's rate design proposals are inconsistent with energy efficiency since it reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable. As an example, in the extreme case of a Straight Fixed Variable ("SFV") rate design, customers will pay the same charge regardless of their usage level. As a result, inefficient customers would pay the same monthly utility bill as relatively more efficient customers, negating all incentive to seek greater efficiency.

Q. HAVE OTHER COMMISSIONS RECOGNIZED THE DETRIMENTAL EFFECT THAT INCREASED FIXED CHARGES CAN HAVE ON ENERGY EFFICIENCY?

A. Yes. In rejecting a request by Baltimore Gas and Electric ("BGE") to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage. Specifically, it stated:

> ...we concur with OPC that residential customer charges should not be increased at this time. Consistent with this decision, we reject BGE's proposal to increase either residential or non-residential customer charges. This decision will afford ratepayers a better opportunity to control their monthly bills by controlling their energy

usage. This decision is consistent with EmPOWER Maryland goals and with our decision in BGE's last base rate case.[97]

Q. ARE THERE ANY COMMISSIONS IN THE MID-WEST THAT HAVE ACKNOWLEDGE THAT INCREASES IN FIXED CHARGES CAN NEGATIVELY IMPACT ENERGY EFFICIENCY AND CONSERVATION EFFORTS?

A. Yes. The Montana Public Service Company rejected the proposed straight fixed variable rate design of Energy West Montana citing a number of reasons including the impact of the proposal on energy conservation efforts. The Commission stated in its decision that:

> The Commission agrees that most distribution costs are not avoidable, and that volumetric distribution charges may encourage conservation actions that, all other things being equal, reduce the utility's embedded cost recovery between rate cases and contribute to future rate increases.
>
> ...
>
> The Commission agrees that an SFV rate design is a clean and administratively inexpensive way to decouple revenue from volume. An often-cited public policy justification for revenue decoupling is to remove the volume disincentive for cost-effective conservation investment by a gas distribution company, which through SFV and other decoupling methods

[97] In The Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates. Maryland Public Service Commission. Case No. 9326. Order No. 86060, Issued December 13, 2013, p. 105.

is rendered indifferent to the volume of gas consumed. Yet, SFV rates decouple revenue at the cost of decreasing returns to conservation investment by customers. For this reason the net conservation benefit of revenue decoupling via SFV rates is not clear, and may be negative.[98]

Q. DOES AN INCREASE IN FIXED COST RECOVERY IN A CUSTOMER CHARGE HAVE AN IMPACT ON CUSTOMERS WITH OR CONSIDERING DISTRIBUTED ENERGY RESOURCES ("DER")?

A. Yes. An increase in fixed cost recovery in a customer charge may negatively impact a DER customer by reducing its costs savings and its return on its investment. High fixed customer charges reduce price incentives for energy efficiency and usage reduction while limiting the ability of customers to control their bills. This is because generally, when fixed charges such as the customer charge are increased it is usually offset by a decrease in the per kWh energy charge, as a result it reduces the value of the kWh saved. Thus, current DER customers are harmed due to the reduction and cost savings and return on its investment, potential DER customers may also view this as a disincentive to invest in DER as they will now incur a longer payback period on its investment.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE IMPACT THAT THE COMPANY'S RATE DESIGN PROPOSALS MAY HAVE ON ENERGY EFFICIENCY AND DISTRIBUTED GENERATION?

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[98] Montana Public Service Commission, In The Matter Of Energy West Montana, Application To Establish Increased Service Rates In Its Great Falls, Cascade, And West Yellowstone Service Areas, Docket No. D2010.9.90, Order No, 7312c, November 17, 2011, pp.29-30.

A. The Company's proposed rate design, particularly its movement toward higher fixed cost recovery should be rejected. The Company's proposed rate design does not promote energy efficiency or the installation of distributed energy resources. The Company's proposed rate design provides a disincentive for customers to conserve energy and make investments in energy efficiency or DER measures.

c. Customer charge proposals will likely be regressive

Q. DOES THE COMPANY MAKE ANY OTHER ARGUMENTS CONCERNING ITS PROPOSAL TO INCREASE CUSTOMER CHARGES?

A. Yes. The Company argues that increased customer charges will improve customer equity. It argues that keeping fixed charges "unreasonably low" will benefit both high and low income customers and is therefore an inefficient means of helping low income customers.[99]

Q. DOES THE COMPANY PROVIDE ANY ANALYSES TO SUPPORT ITS CLAIM THAT LOW FIXED CHARGES WILL NOT HELP LOW INCOME CUSTOMERS?

A. Yes. The Company presents an analysis of the average usage of its residential customers broken down by whether the customer is receiving LIHEAP assistance. The Company's analysis states that 58 percent of its LIHEAP customers have an average monthly usage in excess of 750 kWh, while only 40 percent of its non-LIHEAP customers have an average monthly usage in excess of 750 kWh.[100]

[99] Direct Testimony of David G. Prazak at 15:19 through 16:1.
[100] Direct Testimony of David G. Prazak, Schedule 6.

Q. DO YOU AGREE WITH THE COMPANY'S ARGUMENT THAT AN INCREASE IN RESIDENTIAL CUSTOMER CHARGES WILL ASSIST LOW INCOME CUSTOMERS?

A. No. The Company's argument is fundamentally flawed since higher customer charges make it increasingly more difficult for lower income households to reduce their electricity bills as a share of their relatively limited income. This is simply regressive and will have deleterious impacts on lower-income households, not positive impacts. Lower income customers are not benefited by reduced price volatility as much as they are by the ability to control their usage and actually reduce their monthly electric bill.

Q. DO YOU AGREE WITH THE COMPANY'S ASSERTION THAT THERE IS NOT A DIRECT CORRELATION BETWEEN LOWER INCOME HOUSEHOLDS AND LOWER ELECTRICITY USE?

A. No. The Company argues that low income households have higher than average electric use because these customers are more reliant on electricity for heating than the Company's other residential customers.[101] While the Company's general statement about the availability of weatherization and energy efficiency appliances for low income households may be true, the Company's assertion requires one to assume that low income households are not necessarily or even generally related to lower electrical use households. The suggestion that electric usage falls as income rises is contrary to basic economic theory that says that the demand for a "normal" good or service increases as

[101] Direct Testimony of David G. Prazak at 17:13-18.

income increases. In fact, there are numerous studies in the academic literature supporting the hypothesis that electricity is a "normal good."[102]

Q. HAVE YOU CONDUCTED ANY ANALYSES EXAMINING THE RELATIONSHIP OF ELECTRICITY USAGE AND INCOME?

A. Yes. Exhibit DED-10 provides the results of an analysis I have performed using data from the 2009 Residential Electricity Consumption Survey ("RECS") produced by the United States Energy Information Administration ("EIA") and household data from the Census division in which North Dakota is located.[103] The results show a positive relationship between electricity consumption (in kWh terms) and income. This clearly shows that as income increases electricity consumption increases, and vice versa: as income decreases, electricity usage decreases. Thus asserting, as the Company does, that electricity usage for low income households is actually equal or higher than higher income households is simply incorrect.

Q. DO LOWER INCOME HOUSEHOLDS SPEND PROPORTIONATELY MORE IN ELECTRICITY THAN HIGHER INCOME HOUSEHOLDS?

A. Yes. Lower income households spend a larger share of their income on electricity than higher income households. Put another way, while households consume more electricity as income increases, the share of their income they spend on electricity decreases as their income increases. Exhibit DED-11 clearly shows this relationship.

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[102] Alberini, A., W. Gans, D. Velez-Lopez. 2011, "Residential consumption of gas and electricity in the U.S.: The role of prices and income," Energy Economics 33, 870-881; Fell, H., S. Li, A. Paul. 2010, "A New Look at Residential Electricity Demand Using Household Expenditure Data," RFF DP 10-57; Reiss. P.C., and M. W. White, 2005, "Household electricity demand revisited," Review of Economic Studies 72, 853-858; and Swan L.G., V. I. Ugursan, 2009, "Modeling of end-use energy consumption in the residential sector: A review of modeling techniques," Renewable and Sustainable Energy Reviews 13, 1819-1835.

[103] This census division includes the states of Alabama, Kentucky, Mississippi, and Tennessee. This is the most detailed level of aggregation available in the RECS.

Consumers with income of less than $10,000 per year spend approximately 15 percent of their income on electricity, while a family that makes between $50,000 and $60,000 per year only spends approximately 1.5 percent of their income on electricity. As income increases further, this percentage continues to decline.

Q. WHAT DO THESE FINDINGS MEAN FOR LOWER-INCOME HOUSEHOLDS UNDER THE COMPANY'S RATE DESIGN PROPOSALS?

A. Lower-income households will likely be impacted negatively and in a fashion disproportionate to higher income households. As I noted earlier, electricity use increases as income increases, meaning that contrary to the Company's assertions, lower-income households will likely use less, rather than more electricity than their upper income counterparts. The Company's residential class revenue requirement, however, is set with an average monthly fixed customer charge across the entire class, meaning that lower than average use customers (like low-income customers) will be harmed more by these rate proposals than upper-income households. This proposal will be additionally harmful when considering the fact that lower-income households will have to give up a proportionately larger share of their disposable income to effectively support the customer charge set by the Company under its fixed customer charge rate design proposals.

d. Proposed rate design is inconsistent with MCCOSS

Q. DOES THE COMPANY FOLLOW THE RESULTS OF ITS MCCOSS WHEN DESIGNING RATES?

A. No. The Company appears to subjectively use the result of its MCCOSS in designing rates for each of its customer classes. In some instances the Company strictly adheres to its MCCOSS in assigning customer charges, facilities charges, and demand

charges, while in other instances the Company does not adhere to the results of its MCCOSS in any form, this issue will be discussed for each individual rate class later in my testimony.

Q. DOES THE COMPANY'S MCCOSS PLAY A SIGNIFICANT ROLE IN ASSIGNING REVENUE RESPONSIBILITIES?

A. No. Although the stated purpose of the MCCOSS is to ensure that prices are set equal to the marginal cost of serving the customer, the Company does relatively little to ensure that the price it charges for service actually matches the results of its own study in any area but the customer charge. Each customer class's revenue responsibility is assigned based upon the Company's CCOSS, not its MCCOSS.[104] As noted earlier, the Company claims to use its MCCOSS to assign intra-class revenue responsibilities to the rate classes within each customer class using the EPMC method. However, in every customer class with more than one rate class, the Company tries to combine this EPMC method with the revenue increases resulting from its embedded CCOSS.

Q. DOES THE COMPANY'S MCCOSS PLAY A SIGNIFICANT ROLE IN DETERMINING THE CUSTOMER CHARGE FOR EACH RATE CLASS?

A. Yes. The Company's stated goal is to align customer charges for all classes with its calculated marginal customer costs.[105] The resulting proposed changes in the customer class are, in some cases, extreme. For example, the Company proposes increasing its Residential customer charge from $8.00 per month to $15.23 per month, an increase of over 90 percent.[106] The Company also proposes increasing the customer

[104] Direct Testimony of David G. Prazak, p. 3:25-30.
[105] Direct Testimony of David G. Prazak, p. 14:3-5.
[106] Direct Testimony of David G. Prazak, Schedule 5. Supplemental Testimony of David G. Prazak, p. 1:22-24.

charge for its General Service TOU, Large General Service (Secondary), and Large General Service – Time of Day (Primary) rate classes from less than $100 to more than $200, in each case more than quadrupling the customer charge.[107]

Q. HAS THE COMPANY'S PROPOSAL TO ABRUPTLY AND IMMEDIATELY ALIGN CUSTOMER CHARGES WITH MARGINAL CUSTOMER COSTS BEEN PROBLEMATIC IN OTHER JURISDICTIONS?

A. Yes. In the Company's 2015 Minnesota rate case, while the Commission largely agreed with the Company's calculation of marginal customer-related costs, it found that "no matter how thoroughly Otter Tail calculated the marginal costs of serving the Residential, Small General Service, and General Service (Secondary) classes, the magnitude of the proposed increases are likely to provoke adverse customer reaction."[108] In that case, the proposed increase in the Residential customer charge was 56 percent. As mentioned earlier, the proposed increase in this case is over 90 percent.

Q. DID THE MINNESOTA COMMISSION FIND ANY OTHER PROBLEMS WITH THE COMPANY'S CALCULATION OF MARGINAL CUSTOMER COSTS?

A. Yes. The Office of the Attorney General in that case argued that because Residential Controlled Demand customers' more expensive meters served to control demand and energy costs, they were unrelated to customer costs and should be excluded

[107] Direct Testimony of David G. Prazak, Schedule 5.
[108] In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E-017/GR-15-1033, Findings of Fact, Conclusions, and Order, May 1, 2017, p. 76.

from consideration in the customer charge.[109] The Commission agreed with this and thus did not grant the requested increase in the customer charge.[110]

Q. DO YOU AGREE WITH THE COMPANY'S GOAL TO ALIGN CUSTOMER CHARGES WITH MARGINAL CUSTOMER COSTS?

A. No. Setting aside the numerous issues with the Company's calculation of its estimated marginal cost, OTP customers will not benefit from these increased customer charges. By shifting revenue recovery from volumetric charges to fixed charges, customers will have less control over their own bill, and will be less incentivized to conserve energy. The primary beneficiary of these increased customer charges is the Company, who will benefit greatly by collecting more of its revenue through fixed charges rather than volumetric charges, thereby shifting risk away from itself and onto the customer.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE COMPANY'S INCONSISTENT APPLICATION OF ITS MCCOSS RESULT FOR RATE DESIGN PURPOSES?

A. The Company asserts that its MCCOSS is the most efficient method to set rates. However, in many instances the Company does not follow the results of its MCCOSS when setting rates. The Company's use of the MCCOSS to design rates should be rejected since the Company does not apply the results of its MCCOSS in a uniform

[109] In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E-017/GR-15-1033, Direct Testimony of Ron Nelson at 70:14-22.
[110] In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E-017/GR-15-1033, Findings of Fact, Conclusions, and Order, May 1, 2017, 9. 75-76.

manner across rate classes, however, the Company in many instances uses its "judgement" to design rates.

e. Proposed rate design will create significant intra-class rate discontinuities.

Q. CAN YOU DISCUSS ANY OTHER CHALLENGES TO THE COMPANY'S RATE DESIGN?

A. Yes. The Company's own analysis shows that its proposed rate design will result in a very large shift in revenue responsibilities within most major rate schedules. In particular, the Company's proposed rate design will result in a radical shift of revenue responsibility from high usage customers to low usage customers. Low usage customers in most rate schedules will likely see double and triple digit percent bill increases while larger users will see small, single digit percent increases, and in some instances, decreases, in their bills. These outcomes raise doubts about the seriousness of the Company's commitments to the goals of rate continuity, rate stability, and rate equity.

Q. DO YOU AGREE WITH THE COMPANY'S POSITION THAT THEIR RATE DESIGN WILL FURTHER RATE EQUITY BETWEEN LARGE AND SMALL USERS WITHIN A GIVEN CLASS?

A. No. I disagree with the Company's claim that their rate design proposals are necessary to correct for intra-class inequities[111] for a variety of reasons. First the Company's position for this purported intra-class equity "problem" is unsupported, and their proposed rate design, which shifts intra-rate class revenue responsibilities from high to low usage customers, is simply a solution in search of a problem. Second, to the extent the Company has a basis for this proposal, it almost entirely rests on its

[111] Direct Testimony of David G. Prazak, 15:9-13.

flawed marginal cost study. Lastly, to the extent there is an intra-class equity "problem," a more gradual approach in correcting these problems would clearly be more preferable to the rate design being proposed by the Company.

Q. PLEASE DISCUSS THE PERCENT INCREASES IN RESIDENTIAL BILLS THAT WILL ARISE FROM THE COMPANY'S RATE DESIGN PROPOSALS.

A. An analysis of these impacts, which comes from a modification of information included in the Company's filing, is provided on page 1 of Exhibit DED-12. The chart examines both absolute bill increases (on the right hand axis) and percent change in bills (on the left hand axis) for residential customers by usage levels. The chart clearly shows that the lowest residential class users will likely see a triple digit percent increase in their bills (119 percent) under the Company's rate design proposals. In fact, 15 percent of the Company's residential customers will see, on average, an estimated bill increase of over 78 percent. However, the largest 15 percent of the Company's residential class users, those using about 1,500 kWhs per month or more, will see only a single digit (six percent) percent bill increase.

Q. DO YOU SEE THE SAME TRENDS FOR THE RESIDENTIAL DEMAND CONTROL RATE SCHEDULE?

A No, primarily due to the fact that this is one rate schedule where the Company has, for no clear apparent reason, deviated from its standard rate design proposal of maximizing customer charges and minimizing volumetric charges. Page 2 of Exhibit DED-12 provides a chart comparing both absolute bill increases and percent changes in bills and shows (a) that the percent change in bills, across all usage levels, hovers within

a relatively tight range of 24 percent to 30 percent and (b) that larger absolute increases in bills increase with usage, as would be expected.

Q. ARE THERE ANY OTHER CLASSES THAT ARE SEEING THESE LARGE VARIATIONS IN INTRA-CLASS BILL IMPACTS ON A PERCENTAGE BASIS?

A Yes, in fact, most classes see these very large swings in bill impacts, within a given rate schedule, for very small usage customers, on the one hand, and very large usage customers, on another. Page 3 of Exhibit DED-12 provides a similar comparison, from data originally provided by the Company, of the proposed bill impacts for small general service customers. In yet another example, the Company proposes to increase rates for the smallest 15 percent of the small commercial customers by over 90 percent. In fact, one-quarter (25 percent) of the small commercial customers are anticipated to have a bill increase of, on average, over 60 percent. At the same time, the Company actually proposed to hold rates constant or give a slight bill decrease to the top 15 percent of the users in the small commercial customer class. This clearly cannot constitute a reasonable degree of intra-class equity or rate continuity.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE INTRA-CLASS RATE DISCONTINUITY OF THE COMPANY'S PROPOSED RATE DESIGN?

A. The Company's proposed rate design will result in customers within the same rate class experiencing large disparities in bill impacts. In just about each rate class, smaller use customers are seeing double and in many instances triple digit bill increases while larger use customers within the same class are seeing smaller rate increase, if not rate decreases. These large disparities in rate impacts further shows the discontinuity and inequity that exists in the Company's proposed rate design. I recommend that the

Commission reject these proposals in favor of more moderate increases to the Company's proposed customer charges and more uniform increases in their respective volumetric charges. I will discuss my rate design recommendations on a rate schedule-specific basis in the following section of my testimony.

D. Residential Rate Design

Q. PLEASE DISCUSS THE COMPANY'S CUSTOMER CHARGE PROPOSALS.

A. The Company proposes to increase residential customer charges from a current level of $8.00 per month to $15.23 per month, a 90 percent increase for those customers.[112] As I noted earlier, there is no way such a large increase can be thought of as being consistent with the Company's purported goals of rate continuity and stability. This is a substantially large increase that will have substantial impacts for many customers. The Company is also recommending a more reasonable increase to the residential controlled demand class (Section 9.02) from a current rate of $18.38 per month to $20.10 per month (a 9.36 percent increase).[113]

Q. HOW DO THE COMPANY'S CURRENT RESIDENTIAL CUSTOMER CHARGE REVENUES COMPARE WITH THE RESULTS OF ITS CLASS COST OF SERVICE STUDY?

A. The residential current customer charge revenues recover about 42 percent of its estimated customer-related costs as estimated by its embedded CCOSS. A summary of the Company's customer related costs and its overall customer charge revenues is provided in Exhibit DED-13. While a 42 percent customer charge revenue recovery

[112] Supplemental Testimony of David G. Prazak, Schedule 2.
[113] Direct Testimony of David G. Prazak, Table 7, p 25.

percentage is, admittedly, low for an electric utility, OTP has a number of riders and other cost recovery mechanisms that can assist in mitigating the impact that a more variable-rate-oriented rate design can have on its overall revenue requirement recovery. While some degree of customer charge increase may be in order, as I will discuss later in my testimony, the Company's proposal to increase residential customer charges by over 90 percent in one rate proceeding alone is entirely unreasonable.

Q. HOW DO THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGES COMPARE TO OTHER ELECTRIC DISTRIBUTION COMPANIES?

A. Exhibit DED-14 provides a survey of current residential and small commercial customer charges for major investor-owned utilities ("IOUs") operating in the Mid-West region.[114] The Company's proposed residential customer charge of $15.23 per month is significantly higher than the regional average residential system charge of $12.08 for comparable regional IOUs. Only seven of the 26 IOUs in the survey have a residential customer charge greater than those being proposed by the Company in this proceeding. This is further reason why the Company's residential customer charge proposal should be rejected.

Q. PLEASE EXPLAIN THE COMPANY'S RESIDENTIAL VOLUMETRIC ENERGY CHARGE PROPOSALS.

A. The Company is proposing to eliminate the winter declining rate block for the residential service class and set summer and winter demand charges at equal rates.[115]

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[114] The surveyed Midwest region included Iowa, Minnesota, Montana, North Dakota, South Dakota, Wisconsin, and Wyoming.

[115] Direct Testimony of David G. Prazak, 23:9-10 and 25:6.

Q. WHAT ARE YOUR RECOMMENDATIONS FOR THE RESIDENTIAL RATE CLASSES?

A. I recommend increases in residential class customer charges that are equal to the system average increase on a percentage basis. I do, however, agree with the Company's proposed customer charge increase for the RCD class. For the Residential Service rate class I recommend that the remaining revenue requirement that is not recovered by revenues associated with my proposed customer charges be applied to the energy charge. As for the RCD class while the Company is proposing to set an equal demand charge for summer and winter which the Company states is necessary because this rate is in "transition,"[116] the Company has not provided any details or analysis as to why it is necessary or appropriate to set an equal demand charge. The Company only states that the proposed changes to the RCD class is to align the rate structure with the MISO Module E resource planning requirements.[117] Also the Company is only proposing to set an equal demand charge for summer and winter for it RCD class however, it interestingly has continued to recognize the summer and winter demand charge differential for all other time of use rate classes in its service territory. Therefore, I recommend that the current summer and winter differential be maintained for the RCD class and that these rates be increased proportionately by the total class increase. The energy charge for the RCD class should be increased to collect the remaining revenue requirement for the class.

E. General Service Rate Design

[116] Direct Testimony of David G. Prazak, 25:6-7.
[117] Company's response to ND-PSC-17.12.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED CHANGES TO THE GENERAL SERVICE RATE CLASSES RATES AND CHARGES?

A. The Company is proposing to set energy charges for the Small General Service (Under 20 kW) above marginal cost and the class customer charge at 99.9 percent of marginal cost.[118] The Company is proposing a differentiation between the customer charges for primary and secondary service to "reflect the difference in marginal cost" for the General Service (20 kW or Greater) rate class. The proposed customer charges was set at 99 percent marginal cost and the facilities charges are set 100 percent at marginal cost for the General Service (20 kW or Greater) rate class. The General Service (20 kW or Greater) class's proposed energy charge is set above marginal energy costs to meet the revenue requirement not recovered by the other changes.[119]

Q. WHAT ARE YOUR RECOMMENDATIONS FOR THE GENERAL SERVICE RATE CLASSES?

A. I recommend that customer charges be increased by the system average increase and that the remaining revenue requirement be recovered through the energy charge. As for the proposed differential between a primary and secondary service customer, the Company has not conducted any analysis, other than its flawed marginal cost analysis, that evaluates the cost differential between these two types of customers. While there could potentially be a cost differential between a primary and secondary service customer, the Company has not accounted for this purported difference in its CCOSS, therefore, it is unclear that this cost differential actually exists. Interestingly, the Company

[118] Direct Testimony of David G. Prazak, 28:13-16.
[119] Direct Testimony of David G. Prazak, 30:6-11.

only acknowledges that this cost differential exists for its larger general service customers but no such adjustment is necessary for its smaller general service customers which also have a primary and secondary classification. Therefore, I recommend that current primary and secondary differentials be maintained in this proceeding and that the Company should provide in its next rate case additional details in its CCOSS which would separately breakout these two sets of customers (for both small and large general service) and provide the cost to serve its primary and secondary general service customers.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED CHANGES TO THE GENERAL SERVICE TIME OF USE RATE CLASS RATES AND CHARGES?

A. The Company is proposing to seasonally differentiate charges and sets the on-peak (declared peak) energy charges at full marginal cost for the General Service Time of Use ("GS-TOU") class. The Company is proposing to reduce the declared peak hours from approximately 200 hours per year to approximately 100 hours per year. The Company is proposing to set the GS-TOU shoulder and off-peak energy charges above marginal energy costs to meet the revenue requirement not recovered by other charges. The Company is also proposing to modify the classification of peak and off peak hours under this rate by extending the time of day concept to Sundays.[120]

Q. WHAT ARE YOUR RECOMMENDATIONS FOR THE GENERAL SERVICE TOU RATE CLASS?

A. I recommend that customer charges be increased by the system average increase for the GS-TOU class. I recommend that the current summer and winter differential be

[120] Direct Testimony of David G. Prazak, 32:6-17.

maintained and that demand charges be increased in proportion to the existing relationship between the demand charge and the energy rate. The remaining revenue increase should be recovered through the energy charge.

F. Large General Service Rate Design

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED CHANGES TO THE LARGE GENERAL SERVICE RATE CLASSES?

A. The Company is proposing changes to the following Large General Service Classes: Large General Service ("LGS"), Large General Service Time of Day ("LGS-TOD"), and Standby Service. OTP is proposing to remove the declining rate block in both the summer and winter rates for the Large General Service Class.[121] The Company is proposing to set seasonal energy charges above marginal costs, with summer energy costs slightly lower than winter energy costs, which it states is consistent with the results of its 2018 Marginal Cost Study. The Company is also proposing to set seasonal demand charges below marginal costs, with the differential between summer and winter demand charges increasing from proposed levels to reflect the difference in seasonal marginal costs. The Company is proposing to set the facilities charges at 100 percent of the marginal cost (except for LGS-TOD Primary Service) and the customer charges at 99.9 percent of the marginal cost. The Company is proposing to significantly increase the customer charge for the LGS-TOD to align with its marginal cost analysis. The Company is also proposing to move demand charges closer to marginal cost and decrease the current energy

[121] Direct Testimony of David G. Prazak, 34:3-5.

charges.[122] For the Standby Service class the Company is proposing to increase customer charges to marginal cost and decrease energy charges for the Standby Service class.[123]

Q. WHAT ARE YOUR RECOMMENDATIONS FOR THE LARGE GENERAL SERVICE RATE CLASSES?

A. The Company's proposed changes to its Large General Service Rate classes similarly to its other proposed rate changes subjectively uses the results of its MCCOSS when designing rates. Once again the Company has only strictly adhered to the results of its MCCOSS in assigning customer charges and the facilities charges where applicable. Therefore, I recommend that customer charges should be increased by the system average increase. I recommend that any revenue responsibilities not recovered through existing customer charge revenues be recovered through the energy charges. I also recommending retaining the existing relationship between the demand charge and the energy rate and recommend allocating the increase on an equal percentage basis between the two components.

G. Farm And Irrigation Service Rate Design

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE FARM SERVICE RATE CLASS.

A. The Company is proposing to set the customer charge equal to the customer charge that resulted from its MCCOSS which as shown in exhibit DED-9 is an increase of 45 percent from the current customer charge. The Company is also proposing to implement a single phase facilities charge of $10.00 per month. Additionally, for the

[122] Direct Testimony of David G. Prazak, Table 13, p. 37.
[123] Direct Testimony of David G. Prazak, Table 14, p. 38.

current tiered three-phase facilities charge the Company is proposing to set a single rate of $20.00 per month. Furthermore, the Company is proposing to remove the declining rate block structure for the winter and summer volumetric energy charge.[124]

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE IRRIGATION SERVICE RATE CLASS.

A. The Company is proposing to significantly increase customer charges for the Irrigation Service class, for instance under rate Option 1 the Company is proposing to increase the customer charge from the current charge of $1.00 to $24.30, an increase of 230 percent. Under the Option 2 rate the Company is proposing some changes similar to the changes proposed for the GS-TOU rate class such as decreasing the declared peak hours in a year from 200 hours to 100 hours and to extend the time of day concept to Sundays. The Company is proposing to set the declared peak energy rate at 100 percent of the marginal cost, which the Company states will give customers a clear signal to curtail usage during peak hours.[125]

Q. WHAT ARE YOUR RECOMMENDATIONS FOR THE FARM SERVICE AND IRRIGATION SERVICE CLASSES?

A. The Company's proposed rate design for the Irrigation class relies on the results of its MCCOSS. The Company has not provided any other analysis that evaluates the peak periods of the Irrigation class other than the MCCOSS.[126] Therefore, I recommend that customer charges should be increased by the system average increase. I

[124] Direct Testimony of David G. Prazak, Table 8, p 27.
[125] Direct Testimony of David G. Prazak, 39:12-15.
[126] Company's response to ND-PSC-17.25.

recommend that any revenue responsibilities not recovered through existing customer charge revenues be recovered through the energy charges.

H. Lighting Service Rate Design

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE LIGHTING SERVICE RATE CLASSES.

A. The Company currently has two lighting classes, Outdoor Lighting-Energy Only and Outdoor Lighting. The Company is proposing to leave the rate structure for the lighting classes unchanged. The Company is proposing to increase the energy charges to meet the class revenue requirement. The Company is also proposing to close the Outdoor lighting class to new customers as a result of its proposed LED lighting tariff.[127]

Q. WHAT ARE YOUR RATE DESIGN RECOMMENDATIONS FOR THE LIGHTING CLASS?

A. I agree with Company's proposal to maintain its current rate structure and to increase the energy charges to recover the class' revenue requirement. However, I do not agree that the Company should close the Outdoor lighting tariff, which I will discuss this issue later in my testimony.

I. Other Class Rate Design Proposals

Q. WHAT OTHER RATE SCHEDULE CHANGES IS THE COMPANY PROPOSING TO MAKE CHANGES?

A. The Company is also proposing to make changes to its Municipal Pumping Service and Civil Defense Fire Siren Service classes. The Company is proposing to set the Municipal Pumping Service class's customer charge at 100 percent of marginal cost and

[127] Direct Testimony of David G. Prazak, 68:11-14.

is proposing to change from a fixed facilities charge per month to a $/kW facilities charge per month for this rate class.[128] The proposed facilities charge for the Municipal pumping class is set at marginal cost. The Company is proposing to make very minimal changes to the Civil Defense Fire Siren class, only slightly increasing the customer charge from $1.00 per month to $1.22 per month and decreasing the energy charge.[129]

Q. WHAT ARE YOUR RATE DESIGN RECOMMENDATIONS FOR THE MUNICIPAL PUMPING AND CIVIL DEFENSE FIRE SIREN CLASSES?

A. I recommend that customer charges be increased by the system average increase for both rate classes. As for the rate structure of the Municipal Pumping class, although the Company proposed movement from a fixed facilities charge to a $/kW charge is consistent with how the facilities charge is applied in the Company's other rate classes the Company has not provided any details or analysis on why it is necessary or appropriate to change the facilities charge for this rate class. Therefore, I recommend that the facilities charge for the Municipal Pumping class remain as a fixed charge unless the Company can show that such a change is necessary. I recommend that the energy charge (and facilities charge where applicable) for both of these rate classes be increased by each class's overall increase.

J. Rate Design Recommendations

Q. PLEASE SUMMARIZE THE DEFICIENCIES YOU HAVE FOUND WITH THE COMPANY'S PROPOSED REVENUE DISTRIBUTION.

[128] Direct Testimony of David G. Prazak, 42:3-5.
[129] Direct Testimony of David G. Prazak, Table 18, p. 43.

A. The Company's does not appear to follow any underlying methodology or objective assigning the revenue requirement to its rate classes. The Company's revenue distribution does not provide any cap on the amount of an increase that any one rate class may receive. The Company appears to just use its judgement without any explanation as to why one class may receive an overall increase of 179 percent while another class only receives an increase of 78 percent.[130] While some judgment is necessary in assigning revenue requirements to rate classes, the revenue distribution should follow a systematic uniform approach in order to ensure that one rate class is not overly burdened by a revenue increase when compared to another rate class.

Q PLEASE SUMMARIZE THE DEFICIENCIES YOU HAVE FOUND WITH THE COMPANY'S RATE DESIGN PROPOSALS

A. The Company's rate design proposals in many instances are excessive, particularly its proposed customer charges for many of its rate classes. The Company uses its flawed MCCOSS to set rates in a manner that is just as subjective of using the embedded COSS to set rates and charges. The Company's rate design proposal does not reflect rate continuity and in many instances could result in rate shock.

Q. SUMMARIZE YOUR REVENUE DISTRIBUTION AND RATE DESIGN RECOMMENDATIONS.

A. I make the following revenue distribution and rate design recommendations:

- Class revenue responsibilities should be set using a two-step methodology. In the first step, under-earning classes should receive an increase equal the 1.25 times the

[130] Company's Application, Attachment 44 Vol 2b DGP-1 Schedule 4 Customer and Rate Class Allocations.xlsx.

system average increase. In the second step, any remaining revenue deficiency should be allocated to the remaining rate classes relative to their current test year revenues.

- Customer charges should be increased by the system average increase, except for the Residential Control Demand class which should receive a customer charge increase that is equal to the one proposed by the Company.
- Distribution rates should be increased according to the results of my proposed CCOSS with the prescribed increase allocated to the volumetric and demand components on an equal percentage basis.

VI. Other Tariff Revisions

A. Residential Time of Day Pilot Program Tariff

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RESIDENTIAL TIME OF DAY PILOT PROGRAM TARIFF.

A. The Company states that the Residential Time-of-Day Pilot ("Pilot") proposal is designed to offer rates with seasonal and time of day differences in order to align with the Company's three rate structure objectives: (1) learn from and respond to customers; (2) assess system costs and revenues; and (3) inform future automated metering infrastructure ("AMI") investments.[131] The Company is limiting the pilot to only 50 single-metered customers served on the Residential Service tariff. The proposed Pilot includes three time-of-day periods (on-peak, shoulder, and off-peak) for both summer and winter seasons. The Company states that the time of day periods are designed based on forecasts of the MISO energy market and reflect the marginal cost of service.[132]

Q. WHY HAS THE COMPANY LIMITED THE PILOT TO ONLY 50 CUSTOMERS?

[131] Direct Testimony of David G. Prazak, 55:3-4 and 13-16.
[132] Direct Testimony of David G. Prazak, 55:5-10.

A. The Company states that limiting the Pilot to only 50 customers will allow for cost effective and statistically meaningful results.[133] The Company further asserts that it is relying on the "central limit theorem" stating that the theorem holds true for sample sizes over 30, therefore they have expanded the Pilot participation to 50 customers in order to include additional sample points for attrition purposes.[134]

Q. IS THE PILOT LIMITED IN DURATION?

A. Yes. The Company is proposing that the Pilot program remain open for two years beginning January 1, 2019.[135] The Company states that not opening the tariff until January 1, 2019 is necessary to allow additional time for the Company to develop marketing material, install meters, establish other program monitoring, and sign up customers to participate in the pilot.[136]

Q. ARE THE CUSTOMERS WHO PARTICIPATE IN THE PILOT REQUIRED TO REMAIN ENROLLED FOR THE ENTIRE TWO YEARS?

A. No. The Company states that preference will be given to residential customers that agree to remain on the tariff for a minimum of 12 months. However, customers can choose to take service under the program for a period of three months if the customer chooses to return to another available tariff after the three months, the customer will pay a $20 fee for the removal of the time of day meter.[137] Although customers are not required to remain enrolled in the Pilot for the full two-year term the Company says that they will make the effort to keep the Pilot fully subscribed for the two-year period.[138]

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[133] Direct Testimony of David G. Prazak, 58:16-17.
[134] Direct Testimony of David G. Prazak, 58:21-24.
[135] Direct Testimony of David G. Prazak, 58:28-29.
[136] Direct Testimony of David G. Prazak, 58:29-3 through 59:1-2.
[137] Direct Testimony of David G. Prazak, 59:5-12.
[138] Direct Testimony of David G. Prazak, 59:15-17.

Q. HOW DID THE COMPANY DETERMINE THE PROPOSED $20 REMOVAL FEE?

A. The Company provided in discovery that it used the loaded rate for a lineman with truck of $67 per hour and assumed 45 minutes for transportation and replacement of the meter, which resulted in a total removal cost of $50.25.[139] However, the Company has decided to propose $20 for the removal cost because it believes that "these revenues to be very minimal but help to contribute to the costs of removal and reduce cross-subsidies."[140]

Q. HAS THE COMPANY PROPOSED ANY EVALUATION OR REVIEW PERIOD AFTER THE TWO-YEAR TERM OF THE PILOT HAS ENDED?

A. No. The Company has not proposed any evaluation or review period to occur after the two-year term of the pilot has ended in order for stakeholders to evaluate the effectiveness of the program. The Company has stated that it intends to convert the pilot program to a permanent program based on the outcomes of its three objectives.[141] However, the Company stated in discovery that it will review the results of the program internally and it will determine after its evaluation if the program should be terminated or modified.[142] The Company further stated that if customer response is positive it will make a formal filing with the Commission to make the pilot program a long-term program.[143] The Company states that it would include in that formal filing "participation levels, customer experiences, and reasons for making the program permanent long-term."[144]

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[139] Company's response to ND-PSC-18.25.
[140] Company's response to ND-PSC-18.25.
[141] Company's response to ND-PSC 01.30.
[142] Company's response to ND-PSC-18.24.
[143] Company's response to ND-PSC-18.24.
[144] Company's response to ND-PSC-18.24.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED RESIDENTIAL TIME OF DAY PILOT?

A. No. The underlying data used to design the differential in time periods and costs is based on the Company's MCCOSS and suffers from the same allocation flaws addressed previously in my testimony. The Company has not undertaken any other studies or analyses in determining the appropriate time period differentials or rates other than its MCCOSS.[145] Moreover, it does not appear that Commission Staff or any other stakeholders were engaged in any discussion regarding the design and implementation of a residential TOD tariff to evaluate the various methods and approaches used to set time of use differentials and to design rates for a residential customer.

Q. DO YOU HAVE ANY RECOMMENDATIONS IF THE COMMISSION IS TO APPROVE THE PROPOSED RESIDENTIAL TIME OF DAY PILOT?

A. Yes. The proposed Pilot is designed as voluntary and temporary and, in theory, is being created in order for the Company to learn more about residential demands and usage patterns. The residential class represents almost 78 percent of the Company's total customers and nearly 20 percent of the Company's distribution system peak demand. Therefore, its demand and usage data are essential in the Company's planning process. If the Commission chooses to approve the tariff as currently proposed, I recommend that the Commission direct the Company to file the results of its Pilot program with the Commission within six months of the conclusion of the Pilot. This filing should be made in order for the Commission and all stakeholders to evaluate the effectiveness of the pilot program and to facilitate a discussion regarding the Company's objectives and

[145] Company's response to ND-PSC-18.22.

the results of the program as well as to offer input in methods to offer a more effective rate design if necessary. Additionally, I recommend that the Company should not charge a $20 meter removal fee during the Pilot program period for customers who enroll in the Pilot and later choose to move back to one of the other residential customer tariffs. Customers should not be held accountable for these costs during the Pilot program because the rates of the Pilot are set using a MCCOS that contains questionable results. Therefore, should the customer find that these rates are not effectively set or providing appropriate price signals during the Pilot program period, they should not be penalized for deciding to move back to another residential rate tariff.

B. Generation Cost Recovery Rider

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED GENERATION COST RECOVERY RIDER.

A. The Company's proposed Generation Cost Recovery Rider ("GCRR") is a cost recovery mechanism designed to recover the costs associated with generation additions. The Company states that the proposed rider is similar to its current Transmission Cost Recovery Rider ("TCRR").[146] The Company states that the GCRR will be used to recover the costs of the Astoria station generation project.[147]

Q. IS THE COMPANY PROPOSING TO RECOVER ANY COSTS UNDER THE GCRR IN THIS PROCEEDING?

A. No. The Company is not proposing to recover any costs associated with the Astoria Station Generation Project under the rider in this proceeding. The Company is

[146] Direct Testimony of David G. Prazak, 64:2-3.
[147] Direct Testimony of David G. Prazak, 64:3-4.

only requesting to establish the rider so it will be in place when the Company needs to begin to recover the costs associated with the generation station investments.

Q. HOW IS THE PROPOSED GCRR DESIGNED?

A. The Company states that the proposed GCRR is designed after its Environmental Cost Recovery Rider ("ECRR").[148] Similar to the ECRR, the proposed GCRR uses a cost recovery factor which will apply to customers' bills on a percentage basis.[149] The GCRR will be tracked separately with its own revenue requirement and true-up adjustment. However, the Company proposes that the GCRR charges be included in the current "Energy and Renewable Adj." line item on the customer bills.[150]

Q. HOW LONG IS THE PROPOSED GCRR TO REMAIN IN PLACE?

A. The Company is proposing to keep the GCRR in place indefinitely.[151] Although, the Company states that the GCRR is necessary to recover the costs associated with the Astoria station, the rider will not sunset/expire once the Astoria project has come on line and the costs are folded into base rates. Instead the Company intends to keep the GCRR rider open and active in order to collect revenue for any other future generation plant infrastructure investments that are approved by the Commission.[152]

Q. DOES THERE APPEAR TO BE A REASON WHY THE COMPANY WOULD LIKE TO KEEP THIS TARIFF IN PLACE INDEFINITELY?

A. Yes. Company documents suggest that it plans on developing or purchasing additional generation plant resources in the future. For instance, the Company states that

[148] Direct Testimony of David G. Prazak, 64:9-10.
[149] Direct Testimony of David G. Prazak, 64:10-12.
[150] Direct Testimony of David G. Prazak, 64:12-14.
[151] Company's response to ND-PSC 09.7.
[152] Company's response to ND-PSC 09.7.

in addition to the Astoria project, it will begin construction in 2019 on the 150 MW Merricourt wind project located in southeast North Dakota.[153] As another example, the Company also clearly indicates that it plans to "evaluate a utility-scale solar project during the next five years".[154] The logical conclusion of these anticipated activities and the Company's stated intentions, indicates that it would like to keep its proposed GCRR open-ended in order to have the ability to quickly recover, outside of a rate case, the costs associated with these future investments.

Q. IS ACCELERATED COST RECOVERY NEEDED FOR THE COMPANY TO MAKE THESE GENERATION INVESTMENTS?

A. No, it does not appear that accelerated cost recovery is necessary for the Company to make these generation investments, particularly when the need for many of the projects outside of the test year are speculative, such as the "utility scale solar project", which does not appear to have been placed before the Commission for an evidentiary review. Furthermore, the Company itself has clearly indicated that it will continue to make the necessary generation plant investments even if the GCRR is rejected in this proceeding.[155]

Q. IS THE COMPANY PROPOSING TO CAP THE COSTS RECOVERED THROUGH THE PROPOSED GCRR?

A. No. The Company asserts that an investment cap is unnecessary since it is only requesting the establishment of a rider, and there is no pending plan to recover any costs in the GCRR at this time. The Company states that when costs incurred on the Astoria

[153] Company's response to ND-PSC-13.03.
[154] Company's response to ND-PSC-13.03.
[155] Company's response to ND-PSC-09.7.

project become "material," it will file a request with the Commission for approval to include these generation development costs in the GCRR.[156] The Company states that it believes that proceeding would be the more appropriate time to address investment caps for the GCRR.[157]

Q. DO YOU AGREE THAT AN INVESTMENT OR SOME FORM OF RATE CAP SHOULD BE SET LATER, IN SOME UNDEFINED FUTURE PROCEEDING?

A. No. The Company is proposing to establish the rider in this proceeding, not a future proceeding. Therefore, any cap on investments or rates should be set in this proceeding evaluating the merits of the rider, its need, and its structure. Infrastructure tracker mechanisms that exclude some type of investment or rate cap run the risk of overcapitalization and/or capital investment inefficiencies. Further, a rate impact cap can be an important ratepayer protection since it limits the impact of a utility's generation plant investments on household, business, or industrial customers' electric bills and preserves the over-arching policy goals of rate continuity and gradualism between rate cases.

Q. WOULD AN INFRASTRUCTURE INVESTMENT CAP OR RATE CAP MEAN THAT THE COMPANY IS INCURRING AN INVESTMENT DISALLOWANCE?

A. No. An investment cap or rate cap only limits the amount of the investment that is eligible for accelerated recovery, either in total, or in any given year. Ultimately, these amounts will be allowed into rates, if prudently incurred, upon review in the following year (if the total investment is below the cap), or at the time of the Company's next full rate case.

[156] Company's response to ND-PSC 09.7.
[157] Company's response to ND-PSC 09.7.

Q. IS THE COMPANY PROPOSING ANY ANNUAL REVIEW PROCESS FOR THE PROPOSED GCRR REVENUE REQUIREMENTS?

A. Yes. The Company is proposing to file an annual true-up for cost recovery under the proposed GCRR. The Company states that it will file annually an application to update the rate each year in which it will provide updated cost information for review with each update application.[158] The Company further states that each update application will be subject to the Commission's approval.[159]

Q. DOES THE COMMISSION HAVE ANY PRECEDENT IN APPROVING COST RECOVERY RIDERS OR TRACKER MECHANISMS?

A. Yes. The Commission has in the past approved a number of cost recovery/tracker mechanism for the Company including its TCRR, ECRR, Economic Development Cost Removal Rider ("EDCRR") and Renewable Resource Cost Recovery Rider ("RRCRR").[160] Additionally, the Commission most recently approved a generation resource cost recovery rider for Montana-Dakota Utilities Company in Case No. PU-14-108.[161]

Q. DO YOU AGREE THAT THE GCRR TRACKER NEEDS TO BE ESTABLISHED?

A. No. The Company has not indicated an immediate need for the cost recovery mechanism or that postponing the cost recovery for the investments of its Astoria project to a future rate proceeding would result in a financial hardship for the Company. The

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[158] Company's response to ND-MLEC-209.
[159] Company's response to ND-MLEC-209.
[160] See Company's tariff available at: https://www.otpco.com/pricing/north-dakota/rates-rules-and-regulations-nd/.
[161] Case No. PU-14-108, Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. Generation Resource Recovery Rider Tariff, Order on Settlement, August 20, 2014.

Company is simply proposing to recover the costs for investments that would be made during the normal course of business in a tracker mechanism for special ratemaking treatment and cost recovery. In a typical base rate case, costs associated with new projects are typically examined in great detail, prior to the regulatory authority allowing these costs to be recovered from ratepayers. The regulatory lag and detailed review present in the rate case process serves to mitigate potential inefficiencies associated with large construction programs or projects. This occurs because it provides the utility with an incentive to effectively prioritize projects as well as motivates the utility to control costs in order to minimize the under recovery of capital expenditures and the return on those investments that will not be recovered between rate cases. Additionally, the utility may be more cognizant of its investments in order to avoid the risk of the investments being found to be imprudent and as a result be disallowed for recovery. Thus, the Company's request for the proposed GCRR merely is to shift costs and risks from the Company and its shareholders onto ratepayers.

Q. DO YOU HAVE ANY RECOMMENDATIONS SHOULD THE COMMISSION APPROVE THE GCRR IN THIS PROCEEDING?

A. Yes. I recommend that if the Commission approves the proposed GCRR in this proceeding that the cost recovery under the rider be limited to the costs associated for the Astoria Project and that the GCRR be subject to a sunset review when the Astoria plant is moved into rate base in the Company's next rate case. Cost recovery trackers and mechanisms should be tailored to the program and projects to which they are designed to recover costs. If the Company chooses to apply for accelerated cost recovery for another project or program then the Company should propose a method for cost

recovery at that time. Additionally, I recommend that a rate cap be set in this case for the allowed revenue requirement that can be recovered through the GRCC in any year. Although the Company states that it currently cannot estimate the current rate impacts, it should have a general capital expenditures plan for the Astoria plant in which a rate cap can be derived.[162] The Company does not have a large customer base in North Dakota so spreading cost recovery to future periods may help to alleviate rate pressures in a given year on the Company's customers.

C. LED Street and Area Lighting – Dusk to Dawn

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED LIGHT EMITTING DIODE ("LED") STREET AND AREA LIGHTING – DUSK TO DAWN TARIFF?

A. The Company's proposed LED Street and Area Lighting tariff is a new tariff designed to provide customers with LED lighting fixtures. The proposed tariff is comprised of LED outdoor lighting and flood lighting, aluminum alloy poles, and LED floor visor. Customers taking service under the proposed LED tariff will still be provided the same service including "illumination service, equipment installation, asset rental, electricity, and maintenance."[163] The Company states that it is making this proposal at this time because prices for the technology are "now reasonable" and communities in its service territory are requesting LED lighting.[164] The Company also states that its proposed offerings are "compatible" with their current offerings and have even taken the extra step to provide offerings to meet "Dark Sky" compliance rules.[165]

Q. HOW DID THE COMPANY DESIGN THE RATES FOR THE LED TARIFF?

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[162] Company's response to ND-PSC 09.7.
[163] Direct Testimony of David G. Prazak, 64:26-27.
[164] Direct Testimony of David G. Prazak, 65:19-21
[165] Direct Testimony of David G. Prazak, 65:27-27.

A. The Company states that it used its MCCOS as a guide in setting rates by including the capital and O&M costs for including a new LED fixture.[166] The Company states that next it compared the marginal cost-based revenues to the embedded cost proposed revenues for the Lighting class in order to design revenues that will result in total Lighting class revenues that are equal to those in the CCOSS.[167] In order to match these revenues, the Company states that it used intra-class Lighting revenues to the different Lighting rate classes using a Weighted Average Method of Allocating revenue requirements for the current fixtures in the corresponding LED fixture types.[168]

Q. IS THE PROPOSED LED TARIFF AN OPTIONAL TARIFF FOR CURRENT CUSTOMERS?

A. No, not entirely. While the LED tariff is proposed to be open for new customers, the Company is proposing to close its Outdoor Lighting tariff to new customers and all replacements. The Company proposes that current customers will be served on the closed rate until their existing light fails, at such time the lighting customer will be required to replace the failed fixture with and LED fixture.[169]

Q. WHY IS THE COMPANY PROPOSING TO CLOSE THE CURRENT LIGHTING TARIFF?

A. The Company states that it is proposing to close the current outdoor lighting tariff for two reasons, stating it believes that (1) having two different lighting technologies, in the long term, is unsustainable from a cost and supply perspective and, (2) the new LED

[166] Direct Testimony of David G. Prazak, 67:2-5.
[167] Direct Testimony of David G. Prazak, 67:6-7.
[168] Direst Testimony of David G. Prazak, 67:6-14.
[169] Direct Testimony of David G. Prazak, 68:11-14.

options are more efficient than the current high-intensity discharge ("HID") technologies, and LED's have much longer lifetimes for reduced O&M expenses.[170]

Q. HAS THE COMPANY UNDERTAKEN A SEPARATE COST OF SERVICE STUDY EVALUATING THE LIGHTING CLASS?

A. No, not exactly. The Company has provided its analysis of the marginal costs and proposed rate design for the LED tariff in discovery.[171] However, the Company has not provided any analysis which evaluated individually the cost to serve the lighting class outside of what has been provided in the Company's CCOSS.

Q. DO YOU AGREE THAT CURRENT LIGHTING CUSTOMERS SHOULD BE MOVED TO THE LED TARIFF?

A. No, while LED prices may have decreased in recent years, not all customers may find these prices to be affordable. The proposed LED tariff should be an optional tariff for those customers looking for more efficient lighting choices. The Company should not force all of its lighting customers to take service on the proposed LED tariff when the cost of that tariff may not be economical or affordable for that customer. Furthermore, the Company has not undertaken any study or analysis that explicitly examines the cost to serve its street lighting rate class the Company has only provided a comparison of current costs versus marginal costs and the estimated impact on class revenue.[172]

Q. HAVE ANY OTHER STATE COMMISSIONS RECOGNIZED THE IMPORTANCE OF THE NEED FOR A COST ANALYSIS FOR STREET LIGHTING CUSTOMERS?

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[170] Company's Response to ND-PSC-18.30.
[171] Company's response to ND-PSC-18.28.
[172] Company's response to ND-PSC-18.28, Attachment 1 ND-PSC-18.28.

A. Yes. The Maryland Public Service Commission ("MDPSC") and the Michigan Public Service Commission ("MPSC") have both acknowledged the importance of the need for a cost analysis for street lighting customers when proposing LED tariffs. For instance, the MDPSC opened a Phase II proceeding in Case No. 9217 after a number of intervenors looking for more efficient lighting options found issues with the Potomac Electric Power Company's ("Pepco") proposed revisions to its street lighting tariffs, citing that the proposed revisions were excessive and based on outdated technologies.[173] The Commission, in opening a Phase II proceeding, appeared to have agreed that further cost analysis was necessary to set rates for the Street lighting customers and such analysis should include LED fixtures as an option.[174] In the Phase II proceeding, Pepco filed a cost of service study specific to the lighting class which identified only the costs to serve its street lighting customers.[175] The case ultimately resulted in a Settlement Agreement that was approved by the Commission. Additionally, DTE Electric Company, in its 2015 rate case, Case No. U-17767, proposed to "transition" customers from its experimental LED tariff to its new lighting tariff.[176] However, the Commission found that the Company

[173] Maryland Public Service Commission, Case No. 9217, In The Matter Of The Application Of Potomac Electric Power Company For An Increase In Its Retail Rates For The Distribution Of Electric Energy, Order No. 83516, August 6, 2010, p. 71.
[174] Maryland Public Service Commission, Case No. 9217, In The Matter Of The Application Of Potomac Electric Power Company For An Increase In Its Retail Rates For The Distribution Of Electric Energy, Order No. 83516, August 6, 2010, p. 71.
[175] Maryland Public Service Commission, Case No. 9217, In The Matter Of The Application Of Potomac Electric Power Company For An Increase In Its Retail Rates For The Distribution Of Electric Energy, Direct Testimony of Elliot Tanos, November 30, 2010, p. 3.
[176] Michigan Public Service Commission, Case No. U-17767, In the matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority, Notice of Proposal for Decision, October 8, 2015, p. 305.

failed to support the reasonableness of its revisions[177] and that its lighting proposal was not cost based.[178]

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE LED TARIFF SCHEDULE?

A. Although I agree that the Company should offer LED lighting fixtures to its customers, I recommend that the proposed LED tariff should be an optional tariff for those customers looking for more efficient lighting choices. The Company should not force all of its lighting customers to take service on the proposed LED tariff when the cost of that tariff may not be economical or affordable for that customer. Therefore, I also recommend that the current Outdoor lighting tariff should remain open until the Company has shown that the LED tariff is the most economical and viable option for its customers.

D. Air Conditioning Rider

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED CHANGES TO ITS AIR CONDITIONING RIDER?

A. The Company is proposing to add a new option to the existing Air Conditioning Control Rider for Commercial customers (taking service on Sections 10.01 and 10.02). The rider allows commercial customer incentives of $6.00 per ton of cooling capacity, per month, during the program billing months of June through September.[179] The Company

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[177] Michigan Public Service Commission, Case No. U-17767, In the matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority, Order, December 1, 2015, p. 129.

[178] Michigan Public Service Commission, Case No. U-17767, In the matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority, Notice of Proposal for Decision, October 8, 2015, p. 313.

[179] Direct Testimony of David G. Prazak, 69:22-23.

states that this credit amount is consistent with other utilities in the region, and consistent with pricing offered to the Company's Minnesota customers.[180]

Q. HOW DID THE COMPANY DETERMINE THE INCENTIVE AMOUNT?

A. The Company states that it determined the incentive amount by evaluating the control hours, load reduction, and marginal cost of these hours to determine the cost of avoided service for control periods. They found this amount to be $6.94 per month. However, after subtracting equipment costs used to implement load control, OTP rounded up to $6 per month which it states was "for ease of administration and benefit to the customer".[181]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED ADDITION OF ELIGIBLE COMMERCIAL CUSTOMERS TO THE AIR CONDITIONING CONTROL RIDER?

A. Yes. Demand-side management and load control programs help to reduce demand during the utility's system peak periods which can help to lower costs for the utility and its customers. The Company's proposal to expand the air conditioning load control tariff to include commercial customers seems reasonable.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED OTHER TARIFF REVISIONS.

A. I make the following recommendations regarding the Company's other tariff revision proposals:

[180] Direct Testimony of David G. Prazak, 69:23-25.
[181] Company's response to ND-PSC-18.31.

- The Company's Residential TOD tariff revisions should be rejected since the proposal is not based with any definitive evidence and relies almost exclusively on the results of the Company's flawed MCCOSS. If the Commission chooses to approve the proposed tariff it should require the Company to file the results of its Pilot program within six months of its conclusion. I also recommend that the Commission reject the Company's proposed $20 meter removal fee since this is a pilot program and customer's should not be required to pay a meter removal fee should they find that the rates are not providing appropriate price signals.
- The Commission should reject the Company's Generation Cost Recovery Rider ("GCRR") proposal since the need for this rider has not been proven. If the Commission approves the GCRR, I recommend that GCRR cost recovery be limited to investments associated with the Astoria Project alone and that the GCRR be subject to a sunset review when the Astoria plant is moved into rate base at the time of the Company's next base rate case. Additionally, I recommend that a rate cap of two percent per year be set in this case for the allowed revenue requirement that can be recovered through the GRCC in any year.
- The Company's proposed LED tariff should be approved but the current outdoor lighting tariffs should remain open to all customers. No customers should be forced to take LED service as proposed by the Company.
- The Company's Air Conditioning Rider should be expanded to include an incentive for commercial customers.

VII. Proposed Economic Development Initiatives

A. Overview of Company's Proposed Economic Development Initiatives

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ECONOMIC DEVELOPMENT INITIATIVES.

A. The Company is requesting Commission approval of three separate economic development initiatives: (1) the inclusion of $200,000 of economic development expenses in its 2018 test year, (2) a proposed Super Large General Service ("SLGS") rate schedule, and (3) a proposed Economic Development Rider ("EDR"). My testimony will address the first two issues since the third is being considered in a separate proceeding. I highlight this third initiative in my testimony in order to highlight how it overlaps with proposals being made in the instant rate case.

B. Test Year Economic Development Expenses

Q. PLEASE DESCRIBE THE COMPANY'S 2018 TEST YEAR ECONOMIC DEVELOPMENT EXPENSES.

A. The Company is proposing to include $200,000 of economic development costs to its 2018 test year expenses.[182] The costs are recorded as sales expenses and allocated entirely to the Company's North Dakota jurisdiction.[183]

Q. WHAT IS THE BASIS FOR THIS REQUEST?

A. The Company claims that its economic development efforts create expanded sales opportunities and slow out-migration of retail customers from rural communities.[184] The Company's arguments suggest that these economic development activities, presumably, will prevent the negative impacts of sales attrition from arising for its remaining retail customers.[185] The Company also claims that these efforts help maintain access to

[182] Direct testimony of Stuart Tommerdahl at 41:2-3.
[183] Company workpaper "56.1 Vol 4A Tab A.04.2 Input summary – NOI.xlsx"
[184] Direct Testimony of Stuart Tommerdhal, 39:9-11.
[185] Direct Testimony of Stuart Tommerdhal, 39:1-5.

healthcare and education, as well as infrastructure.[186] The Company states that attracting new businesses or assisting existing businesses in creating new job opportunities and economic development efforts can "help slow the out-migration of people from our rural communities, which in turn helps communities retain and support essential services like health care, stabilize the community's tax base and maintain the number of students they have in their schools."[187] The Company argues that allowing it to recover these economic development expenses will allow it to help its local economies grow and thrive.[188]

Q. HAS THE COMPANY QUANTIFIED THE BENEFITS OF THIS ECONOMIC DEVELOPMENT SPENDING?

A. The Company notes that, while it is difficult to quantify these benefits,[189] it believes that its past spending has led to the creation of 6,222 jobs and has helped to save 1,069 existing jobs in North Dakota from the period of 1989 to 2007.[190] The Company is unable, however, to identify whether or not these employment benefits were transitory or permanent.[191]

Q. WHAT ACTIVITIES WILL BE ASSOCIATED WITH THESE ECONOMIC DEVELOPMENT EXPENDITURES?

A. The Company plans to hire additional staff in order to participate in more community engagement and local activities designed to attract and retain businesses and industries.[192] The Company states it will use these expenditures to fund activities that

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[186] Direct Testimony of Stuart Tommerdahl at 39:11-14.
[187] Company's response to ND-PSC-10.01.
[188] Direct testimony of Stuart Tommerdahl at 40:20-22.
[189] Direct testimony of Stuart Tommerdahl at 39: 15.
[190] Company's response to ND-PSC 09.12, Attachment 1 to DR ND-PSC-09.12.pdf.
[191] Company's response to ND-PSC 09.12.
[192] Direct testimony of Stuart Tommerdahl at 41:10-16.

facilitate start-ups, expansions, relocations, financing, planning, and other development opportunities.[193] The Company states that its initiatives could "involve collaborating with other stakeholders (city, county, state officials and other economic development orientated entities)" to collectively work with potential business and industries to meet their local siting needs and requests. [194] The Company also notes that it will "enhance the quality of life by helping local and regional community projects including, housing, jobs training, educational, non-profit and other community-based endeavors."[195]

Q. HAS THE COMPANY MADE COMPARABLE ECONOMIC DEVELOPMENT EXPENDITURES IN THE PAST?

A. Yes. The Company spent over $9.7 million on economic development activities from 1989 to 2008.[196] In fact, a settlement related to the Company's 2008 rate case would have allowed $450,000 in economic development expenses to be included for cost recovery in rates.[197] The Commission, however, saw matters differently and ordered that economic development expense provision be removed from the Settlement.[198] The Commission was clear in noting that "the use of ratepayer dollars to fund economic development projects absent evidence that the funding results in reduced rates for all customers continues to be of major concern."[199]

Q. WILL ANY PORTION OF THE COMPANY'S PLANNED ECONOMIC DEVELOPMENT EXPENDITURES BE SUPPORTED BY SHAREHOLDER FUNDING?

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[193] Company's response to ND-PSC 09.14.
[194] Company's response to ND-PSC 09.14.
[195] Company's response to ND-PSC 09.14.
[196] Direct Testimony of Stuart Tommerdahl, 39:29 – 40:2.
[197] NDPSC Case No. PU-08-862 Amended Settlement Agreement, p. 6.
[198] NDPSC Case No. PU-08-862 Order on Settlement, pp.7-8.
[199] NDPSC Case No. PU-08-862 Letter – Questions Regarding Economic Development Costs dated November 4, 2009.

A. No. The Company is proposing to recover the entire $200,000 from ratepayers with no portion of the cost of these economic development expenses being recovered by shareholders.[200]

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S ECONOMIC DEVELOPMENT EXPENSES?

A. I recommend that the Commission reject the Company's proposal to include these expenses in rates. The Commission has clearly expressed concerns about including economic development expenses in rates in the past, particularly when the Company cannot show a companion rate reduction benefit. The Company has not met the Commission's burden of proof for including these economic development expenses in rates and they should be excluded from rates.

C. Proposed Super Large General Service ("SLGS") Rate Schedule

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED SUPER LARGE GENERAL SERVICE SCHEDULE.

A. The Company is proposing a new rate schedule that will apply to customers with an expected metered demand of at least 25 MW at a single metering point, an expected load factor of at least 80 percent, and expected annual energy sales of at least 175,000 MWh's over 12 consecutive billing months.[201] The rate charged to each customer will be determined on a case-by-case basis and cover at least the incremental cost of serving the customer.[202]

Q. WHY IS THE COMPANY PROPOSING THIS RATE SCHEDULE?

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[200] Company response to Data Request ND-PSC-06.20
[201] Company's application, Volume 2D-Proposed Tariff Sheets, Legislative, Super Large General Service Tariff, Section 10.06
[202] Company petition volume 2D, North Dakota Section 10.06.

A. The Company claims that it is proposing this rate schedule in order to attract new loads that are large in size and have high load factors.[203] The Company suggests that pursuing such loads will result in benefits to all customers, not only from a rate perspective, but also from an economic development perspective.[204]

Q. WHY CAN'T THESE CUSTOMERS TAKE SERVICE UNDER THE COMPANY'S EXISTING TARIFFS?

A The Company claims the new tariff is needed because the nature of the targeted loads are much larger, and of higher quality (load factor) than existing loads that are taking service under its existing tariffs.[205]

Q. WHAT CLAIMS DOES THE COMPANY MAKE ABOUT THE ATTRACTIVENESS OF THIS TARIFF TO ITS TARGETED LOADS?

A. The Company claims that the SLGS rate schedule will provide prospective customers with a service offer that is quicker to utilize and will have price certainty.[206] The Company goes further to claim that these tariff qualities will make its North Dakota service territory more attractive for business and industry location decisions.[207] Lastly, the Company claims that the addition of large/high load factor customers will increase demand and energy sales thereby driving down average costs for all customers in future rate cases.[208]

Q. HOW DOES THE COMPANY'S SLGS PROPOSAL DIFFER FROM ITS PROPOSED EDR?

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[203] Company petition volume 2D, North Dakota Section 10.06.
[204] Company petition volume 2D, North Dakota Section 10.06.
[205] Direct testimony of David Prazak at 60:6-10.
[206] Direct testimony of David Prazak at 59:33-60:1.
[207] Direct testimony of David Prazak at 59:33-60:1.
[208] Direct testimony of Stuart Tommerdahl at 43:17-25.

A. The Company's proposed EDR applies to all new customers with an above-average expected seasonal load factor and expected metered demand of at least 500 kW, as well as existing customers with expected metered demand of 1,000 kW and increased demand of at least 500 kW, as well as an above-average seasonal load factor.[209] This is much smaller than the demand required under the SLGS rate schedule. There is also no EDR minimum energy sales requirement much like there is for the SLGS. Finally, the EDR has a benefit restriction that is limited to five years. The proposed SLGS is not limited: the initial service agreement can run for five years, but the Company explicitly states that the SLGS service can be applied indefinitely if the Company's proposed tariff is approved.[210]

Q. ARE THERE ANY DEFICIENCIES ASSOCIATED WITH THE PROPOSED SLGS AS AN ECONOMIC DEVELOPMENT TOOL?

A. Yes. The Company's proposed SLGS service does not require the prospective customer to quantify any economic benefits such as job creation or capital investment before receiving discounted service under the SLGS rate schedule. Second, the Company will calculate the customer's rate using a "proprietary model" which will only be provided to the Commission and presumably its staff, and it will be up to the Commission and staff to regularly review this model to assure it is working appropriately and that the SLGS tariff is operating in a manner consistent with this "model." The model itself calculates the Company's incremental cost to serve a prospective SLGS customer and this "model" is based upon outputs developed in the Company's highly-flawed MCCOSS.

[209] NDPSC Case No. PU-17-238 company petition, Attachment 1.
[210] Direct testimony of David Prazak at 63:12-16.

Finally, the tariff does not provide any penalty for customers who take discounted service under the SLGS yet fail to meet the minimum specified requirements.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED SLGS RATE SCHEDULE?

A. I recommend that the Commission reject the Company's proposed Super Large General Service ("SLGS") tariff since it is potentially in conflict with an alternative economic development rider ("EDR") that is also being proposed by the Company in a separate proceeding. However, if the Commission decides to approve the SLGS rate schedule, I recommend the following provisions:

(1) require a regular review of each customer's contribution to the Company's revenue requirement and subsequent re-approval of the SLGS rate by the Commission;

(2) institute a penalty for customers who take service under the SLGS rate schedule and fail to meet the requirements, such as payment of the difference between the SLGS rate and the applicable rate schedule;

(3) limit the amount of time under which the customer can receive a favorable rate under the SLGS schedule to five years;

(4) require the Company to calculate the incremental cost of serving the prospective customer based upon the situational cost of establishing and providing service rather than relying upon the Company's MCCOSS; and

(5) require the customer to provide evidence of net benefits to ratepayers, such as jobs or capital investment in the Company's service territory.

VIII. Conclusions and Recommendations

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS REGARDING THE COMPANY'S JCOSS.

A. I recommend that the Commission accept the Company's proposed jurisdictional allocations. The Company has adopted a uniform allocation method in both jurisdictions, and this methodology is comparable to what has historically been used in North Dakota. However, while I agree with the Company's proposed jurisdictional allocations there are some areas where the transparency of their analysis could be improved upon for regulatory purposes. Therefore, I also recommend that the Commission order the Company to file, in its next rate case, a transparent JCOSS with cost allocation performed at the detailed FERC account level and that this analysis be provided in an electronic format separate from its CCOSS.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS REGARDING THE COMPANY'S CCOSS.

A. I recommend the Commission utilize a set of alternative CCOSS methodologies that includes: (1) a 12 coincident peak ("CP") methodology to allocate transmission plant costs; (2) a rejection of the Company's minimum system study for allocating distribution plant accounts 364-368; (3) a distribution plant allocation methodology that treats all plant investment as being demand and not customer related; and (4) a methodology that uses customer counts to allocate services-related plant. Furthermore, my review of the Company's CCOSS was significantly impaired by a lack of transparency and support documentation mapping cost of service allocators, and other crucial input data to FERC accounts. Therefore, I recommend that the Commission order the Company, in its next

rate case, to file a transparent and comprehensive CCOSS that documents and maps costs and allocators at the FERC account level to each of its customer classes.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S MCCOSS.

A. I recommend that the Commission reject the Company's MCCOSS. The Company's MCCOSS is flawed and the Company's application of the MCCOSS results are subjective and arbitrary. I recommend that rate schedule revenue responsibilities be set upon the results of my alternative CCOSS and my proposed revenue distribution. Furthermore, the Company's use of the MCCOSS as a basis for its proposed customer charge increases is faulty and, if accepted, would result in substantially large increases for many customer classes.

Q. PLEASE SUMMARIZE YOUR REVENUE DISTRIBUTION AND RATE DESIGN RECOMMENDATIONS.

A. I make the following revenue distribution and rate design recommendations:

- Class revenue responsibilities should be set using a two-step methodology. In the first step, under-earning classes should receive an increase equal the 1.25 times the system average increase. In the second step, any remaining revenue deficiency should be allocated to the remaining rate classes relative to their current test year revenues.
- Customer charges should be increased by the system average increase, except for the Residential Control Demand class which should receive a customer charge increase that is equal to the one proposed by the Company.

- Distribution rates should be increased according to the results of my proposed CCOSS with the prescribed increase allocated to the volumetric and demand components on an equal percentage basis.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S OTHER TARIFF REVISION PROPOSALS.

A. I make the following recommendations regarding the Company's other tariff revision proposals:

- The Company's Residential TOD tariff revisions should be rejected since the proposal is not based with any definitive evidence and relies almost exclusively on the results of the Company's flawed MCCOSS. If the Commission chooses to approve the proposed tariff it should require the Company to file the results of its Pilot program within six months of its conclusion. I also recommend that the Commission reject the Company's proposed $20 meter removal fee since this is a pilot program and customer's should not be required to pay a meter removal fee should they find that the rates are not providing appropriate price signals.
- The Commission should reject the Company's Generation Cost Recovery Rider ("GCRR") proposal since the need for this rider has not been proven. If the Commission approves the GCRR, I recommend that GCRR cost recovery be limited to investments associated with the Astoria Project alone and that the GCRR be subject to a sunset review when the Astoria plant is moved into rate base at the time of the Company's next base rate case. Additionally, I recommend that a rate cap of two percent per year be set in this case for the allowed revenue requirement that can be recovered through the GRCC in any year.

- The Company's proposed LED tariff should be approved but the current outdoor lighting tariffs should remain open to all customers. No customers should be forced to take LED service as proposed by the Company.
- The Company's Air Conditioning Rider should be expanded to include an incentive for commercial customers.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S ECONOMIC DEVELOPMENT EXPENSES?

A. I recommend that the Commission reject the Company's proposal to include these expenses in rates. The Commission has clearly expressed concerns about including economic development expenses in rates in the past, particularly when the Company cannot show a companion rate reduction benefit. The Company has not met the Commission's burden of proof for including these economic development expenses in rates, therefore, they should be excluded from rates.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED SUPER LARGE GENERAL SERVICE TARIFF?

A. I recommend that the Commission reject the Company's proposed Super Large General Service ("SLGS") tariff since it is potentially in conflict with an alternative economic development rider ("EDR") that is also being proposed by the Company in a separate proceeding. However, if the Commission decides to approve the SLGS rate schedule, I recommend the following provisions:

(1) require a regular review of each customer's contribution to the Company's revenue requirement and subsequent re-approval of the SLGS rate by the Commission;

(2) institute a penalty for customers who take service under the SLGS rate schedule and fail to meet the requirements, such as payment of the difference between the SLGS rate and the applicable rate schedule;

(3) limit the amount of time under which the customer can receive a favorable rate under the SLGS schedule to five years;

(4) require the Company to calculate the incremental cost of serving the prospective customer based upon the situational cost of establishing and providing service rather than relying upon the Company's MCCOSS; and

(5) require the customer to provide evidence of net benefits to ratepayers, such as jobs or capital investment in the Company's service territory.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY FILED ON MAY 18, 2018?

A. Yes. However, due to the expedited nature of the procedural schedule in the current proceeding, and the fact that the discovery provided by the Company in this proceeding has often been incomplete, undocumented, and delayed, I reserve the right to amend and/or supplement my testimony should any new evidence materialize between now and the time of the evidentiary hearing.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Power Company
2017 Electric Rate Increase
Application

Case No. PU-17-398

VERIFICATION

STATE OF Louisiana)
) ss.
COUNTY OF East Baton Rouge)

David F. Dismukes being first duly sworn on oath, deposes and states that he has read the testimony and exhibits submitted in the above captioned matter under his name, that they prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.

[name] david e. dismukes

Subscribed and sworn to before me this 14th day of May, 2018.

Notary Public
My Commission Expires at Death

THEA R. SCOTT
NOTARY PUBLIC ID # 135246
STATE OF LOUISIANA
MY COMMISSION IS FOR LIFE