

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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1 **I. Introduction**

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

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

9 **Q. DO YOU HOLD ANY ACADEMIC POSITIONS?**

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

18 **Q. FOR WHOM ARE YOU APPEARING?**

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

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

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1 A. No, I have not.

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

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

7 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

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

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

16 **II. Summary of Findings and Recommendations**

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

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

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

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

A. I recommend the Commission utilize a set of alternative CCROSS 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 CCROSS 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 CCROSS 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 CCROSS and my proposed revenue distribution.

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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

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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

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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.

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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?

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

6 Q. HOW ARE ENERGY-RELATED COSTS DEFINED?

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

10 Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

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

14 Q. IS THIS A RELATIVELY SIMPLE PROCESS?

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

22 Q. HOW DOES A COSS RELATE TO COMMONLY-QUOTED ECONOMIC 23 PRINCIPLES?

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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?

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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

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

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

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

13 **Q. DID THE MPUC APPROVE THE COMPANY’S JURISDICTIONAL**
14 **ALLOCATIONS?**

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

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.

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

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

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

9 **C. Jurisdictional Cost of Service Recommendations**

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

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

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.

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1 **D. Class Cost of Service Study**

2 **Q WHAT IS THE PURPOSE OF THE COMPANY'S PROPOSED CCROSS?**

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

9 **Q. PLEASE DESCRIBE THE DEMAND ALLOCATORS USED WITHIN THE**
10 **COMPANY'S CCROSS.**

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

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

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

A. Yes. I disagree with the use of several of the Company's CCROSS 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. Allocation of Production Plant

Q. PLEASE DESCRIBE THE COMPANY'S D1 ALLOCATOR.

A. The D1 allocator used to allocate production plant in the Company's CCROSS is comparable to the D1 allocator used in its JCROSS. 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.

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

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

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

19 **Q. DOES THE COMPANY USE THE E8760 ALLOCATION FACTOR TO**
20 **ALLOCATE ANY OTHER COSTS IN THE COMPANY CCROSS?**

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.

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

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

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

11 **Q. PLEASE EXPLAIN HOW PRODUCTION PLANT ACCOUNTS ARE TYPICALLY**
12 **ALLOCATED.**

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

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

19 A. Peak demand methods classify all production plant accounts as demand-related
20 with each class receiving a share of those plant costs based upon its contribution to
21 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.

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

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

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

13 **Q. DO YOU AGREE WITH THE COMPANY’S ALLOCATION OF PRODUCTION**
14 **PLANT USING THE E8760 ALLOCATION METHOD?**

15 A. No, not entirely. The Company’s method, admittedly, is consistent with the
16 Commission’s order in its last rate case approving the settlement between parties. The
17 Commission needs to be mindful, however, that there are other ways in which energy-
18 related costs can be blended into a CCROSS, many of which are more common than the
19 strict energy based allocator used by the Company (i.e., the E8760 allocator). This
20 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.

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1 allocated production plant costs using an energy-weighted “Equivalent Peaker”
2 methodology in the past.¹⁵

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

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

17 **2. Allocation of Transmission Plant**

18 **Q. PLEASE DESCRIBE THE COMPANY’S D2 ALLOCATOR.**

19 A. The Company uses the D2 allocation factor to allocate its transmission plant. The
20 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.

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

3 **Q. PLEASE EXPLAIN HOW TRANSMISSION FACILITIES ARE TYPICALLY**
4 **ALLOCATED?**

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

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

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

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.

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

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

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

15 **Q. DO YOU AGREE WITH THE COMPANY’S ALLOCATION OF TRANSMISSION**
16 **PLANT?**

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

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.

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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 CCOS 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.

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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.

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

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

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

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

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

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

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

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

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

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.

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

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

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

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

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

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

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.

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

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

7 **Q. WHAT DOES YOUR ANALYSIS SHOW?**

8 A. My analysis shows that there is no obvious correlation between the number of
9 transformers or the capacity of substations on a per-customer basis with the amount of a
10 utility's fixed charges. For example, MDU Resources has 3.69 transformers per 1,000
11 customers, which is more than four times as many as the Company and is the highest
12 number in the peer group. However, its residential monthly customer charges range from
13 \$5.17 to \$25.00. ALLETE, Inc. has both a higher substation capacity and more
14 transformers on a standardized basis than the Company, but its small commercial
15 customer charge is just \$10.50, less than half of what the Company is proposing. Finally,
16 the two lowest residential customer charges are found in Montana and are from utilities
17 that have relatively high substation capacity and number of transformers on a per-
18 customer basis.

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

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

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

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

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

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

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

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

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1 carrying capability, which can be viewed as a demand-related

2 cost.⁴¹

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

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

12 **Q. ARE THERE ANY OTHER PROBLEMS ASSOCIATED WITH THE COMPANY’S**
13 **PROPOSED MSS?**

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

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.

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

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

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

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

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

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

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.

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1 minimum sized equipment in the form of a code it has not provided any source documents
2 or explanation or details on the size of this “minimum size equipment” nor does it appear
3 that this minimum sized plant item has any actual bearing on the determination of the
4 minimum costs.⁴⁷

5 **Q. IS THE COMPANY’S TREATMENT OF CUSTOMER COSTS CONSISTENT**
6 **BETWEEN THE CCROSS, THE MSS AND THE METHOD IT USES TO SET CUSTOMER**
7 **CHARGES??**

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

⁴⁷ Company’s response to ND-PSC-04.31.

⁴⁸ Company’s response to ND-PSC-04.17.

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

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

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

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

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

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

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

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

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1 A. Yes. The D4 is based on non-coincident kW demands at the secondary service
2 level adjusted for the load carrying capacity included in the hypothetical minimum system.
3 The Company adjusts its NCP demand at the secondary service level by subtracting the
4 3.0 kW/customer it states is “already included in the minimum system portion of the
5 secondary customer component”.⁵⁰

6 **Q. DID YOU MAKE ANY CHANGES TO THE COMPANY’S D4 ALLOCATOR?**

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

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

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

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.

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

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

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

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

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

4 **Q. HOW DID YOU ALLOCATE DISTRIBUTION EXPENSES?**

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

10 **Q. HOW WOULD YOU TYPICALLY ALLOCATE DISTRIBUTION EXPENSES?**

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

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

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

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

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

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

10 **Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE STRUCTURE AND**
11 **FORMAT OF THE COMPANY'S JCOSS AND CCOSS?**

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

18 **E. CCOSS Recommendations**

19 **Q. PLEASE SUMMARIZE YOUR CCOSS RECOMMENDATIONS.**

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

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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 CCROSS 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 CCROSS that documents and maps costs and allocators at the FERC account level to each of its customer classes.

Q. DO YOUR CCROSS 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 CCROSS results in Exhibit DED-2. Using my recommended allocation factors, I have also prepared an alternative CCROSS 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 CCROSS.

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") CCROSS which seeks to determine the allocation of costs across customer classes for a fixed period of time and

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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

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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

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.

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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 to 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.

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1 methodology.⁵⁷ I will discuss this potential inconsistency later in this section of my
2 testimony.

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

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

14 **B. MCCOSS Methodology**

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

17 A. The Company estimates marginal costs in five functional areas that include
18 generation, transmission, ancillary services, distribution, and customer costs. The
19 marginal annualized cost is estimated by adjusting the investment per unit by a general
20 plant loading factor. The resulting figures are multiplied by an annual economic carrying
21 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.

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

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

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

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

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

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.

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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.

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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.

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

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

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

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

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

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

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.

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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?

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.

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1 A. The Company calculated its non-plant-related A&G loader as the average ratio of
2 non-plant-related A&G expenses to O&M expenses over the period 1982-2014. The
3 Company calculated its plant-related A&G loader by regressing its maintenance of
4 general plant expenses on cumulative net additions to its total electric plant from 1982-
5 2014, and then adding its average property and terrorism insurance rate for distribution
6 plant requiring insurance. Finally, a general plant loader was estimated by regressing
7 cumulative net additions to general plant on cumulative net additions to total plant less
8 general plant from 1996-2014.⁷⁵

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

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

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

16 A. As mentioned earlier in this section of my testimony, the Company applied three
17 variations of the EPMC method to allocate the customer class revenue responsibilities to
18 the individual rate schedules. The first method was applied to the Large General Service,
19 Irrigation, Controlled Service Interruptible, and Controlled Service Deferred customer
20 classes.⁷⁷ This method simply assigns each rate schedule a percentage increase equal
21 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.

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

10 [REDACTED]

11 [REDACTED]

12 [REDACTED]

13 [REDACTED]

14 [REDACTED]

15 [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 **Q. HOW DID THE COMPANY ALLOCATE REVENUES FOR THE REMAINING**
19 **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.

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

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

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

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

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

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

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

19 **Q. EXPLAIN HOW THE COMPANY'S MARGINAL COST ANALYSIS IS MORE**
20 **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.

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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 CCROSS 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.

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.

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1 **Q. IS THIS ESTIMATE TRULY MARGINAL IN NATURE?**

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

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

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

17 **E. Recommendations**

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

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

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

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

5 **V. Revenue Distribution and Rate Design**

6 **A. Company Proposed Revenue Distribution**

7 **Q. PLEASE EXPLAIN THE PROCESS BY WHICH CLASS REVENUE** 8 **RESPONSIBILITIES ARE DETERMINED.**

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

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

3 A. The Company's last rate case resulted in a Settlement Agreement which was
4 approved by the Commission.⁸⁹ In the Company's last rate proceeding, all classes
5 received a revenue increase except the large general service ("LGS") rate class.⁹⁰

6 Although there is no explicit discussion regarding how the rates and charges were
7 determined it appears that the rate increase was applied to both customer charges and
8 energy charges, as well as demand charges, where applicable.⁹¹

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

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

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

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

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

6 **Q. PLEASE EXPLAIN WHAT IS MEANT BY A “RELATIVE RATE OF RETURN.”**

7 A. A “relative rate of return” (“RROR”) is simply the ratio of a given class’ estimated
8 rate of return to the overall system rate of return. This ratio can also be thought of as a
9 “unitized” rate of return since each class’ estimate return is standardized to the
10 Company’s overall request. For example, if the residential class is estimated to be
11 earning 11 percent from the CCSS, and if the Company is requesting a 10 percent
12 overall rate of return, then the residential class can be said to have a RROR of 1.10 (i.e.,
13 11 percent divided by 10 percent). RRORs can also be thought of as a special type of
14 index number measuring a specific class’ return relative to the Company’s overall rate of
15 return. Thus, classes with a relative rate of return greater than 1.0 entails that those
16 classes are likely earning an amount greater than the Company’s overall rate of return.
17 Those classes with a relative return below 1.0 can be said to be earning an amount less
18 than the Company’s overall rate of return. Exhibit DED-5 presents the Company’s
19 estimated class relative rates of return under its current and proposed rates.

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

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

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

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

11 A. Yes. Exhibit DED-6 provides a comparison of the RRORs from the 2008 rate case
12 and those filed in this proceeding. The residential class RRORs has remained relatively
13 the same as that filed in the Company's last rate case increasing slightly from 0.51 to
14 0.52. The general service ("GS") and large general service classes are both earning
15 RRORs lower than the prior rate case.

16 **Q. WHAT ARE YOUR REVENUE DISTRIBUTION RECOMMENDATIONS?**

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

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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

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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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

20 A. No, I do not agree with the Company's proposed rate design changes in this
21 proceeding. The Company uses a faulty MCCOSS as the basis in setting its proposed
22 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.

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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 use 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.

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

3 **a. Customer charge proposals are inconsistent with rate continuity**

4 **Q. WHAT IS RATE CONTINUITY?**

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

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

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

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

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

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

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

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

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

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

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

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1 **Q. IS THE COMPANY’S PROPOSED RATE DESIGN, SPECIFICALLY THE**
2 **PROPOSAL TO SIGNIFICANTLY INCREASE THE CUSTOMER CHARGE,**
3 **CONSISTENT WITH THE PROMOTION OF ENERGY EFFICIENCY AND**
4 **CONSERVATION?**

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

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

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

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

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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.

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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?

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.

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

6 **c. Customer charge proposals will likely be regressive**

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

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

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

15 A. Yes. The Company presents an analysis of the average usage of its residential
16 customers broken down by whether the customer is receiving LIHEAP assistance. The
17 Company's analysis states that 58 percent of its LIHEAP customers have an average
18 monthly usage in excess of 750 kWh, while only 40 percent of its non-LIHEAP customers
19 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.

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1 **Q. DO YOU AGREE WITH THE COMPANY’S ARGUMENT THAT AN INCREASE**
2 **IN RESIDENTIAL CUSTOMER CHARGES WILL ASSIST LOW INCOME**
3 **CUSTOMERS?**

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

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

13 A. No. The Company argues that low income households have higher than average
14 electric use because these customers are more reliant on electricity for heating than the
15 Company’s other residential customers.¹⁰¹ While the Company’s general statement
16 about the availability of weatherization and energy efficiency appliances for low income
17 households may be true, the Company’s assertion requires one to assume that low
18 income households are not necessarily or even generally related to lower electrical use
19 households. The suggestion that electric usage falls as income rises is contrary to basic
20 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.

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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.

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.

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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

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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 CCROSS, 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 CCROSS.

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.

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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.

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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.

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1 manner across rate classes, however, the Company in many instances uses its
2 “judgement” to design rates.

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

4 **Q. CAN YOU DISCUSS ANY OTHER CHALLENGES TO THE COMPANY’S RATE**
5 **DESIGN?**

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

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

17 A. No. I disagree with the Company’s claim that their rate design proposals are
18 necessary to correct for intra-class inequities¹¹¹ for a variety of reasons. First the
19 Company’s position for this purported intra-class equity “problem” is unsupported, and
20 their proposed rate design, which shifts intra-rate class revenue responsibilities from
21 high to low usage customers, is simply a solution in search of a problem. Second, to
22 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.

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

4 **Q. PLEASE DISCUSS THE PERCENT INCREASES IN RESIDENTIAL BILLS THAT**
5 **WILL ARISE FROM THE COMPANY’S RATE DESIGN PROPOSALS.**

6 A. An analysis of these impacts, which comes from a modification of information
7 included in the Company’s filing, is provided on page 1 of Exhibit DED-12. The chart
8 examines both absolute bill increases (on the right hand axis) and percent change in bills
9 (on the left hand axis) for residential customers by usage levels. The chart clearly shows
10 that the lowest residential class users will likely see a triple digit percent increase in their
11 bills (119 percent) under the Company’s rate design proposals. In fact, 15 percent of the
12 Company’s residential customers will see, on average, an estimated bill increase of over
13 78 percent. However, the largest 15 percent of the Company’s residential class users,
14 those using about 1,500 kWhs per month or more, will see only a single digit (six percent)
15 percent bill increase.

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

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

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

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

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

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

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

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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 CCROSS. 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.

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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

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.

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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.

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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.

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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 CCOS 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.

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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.

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

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

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

15 **G. Farm And Irrigation Service Rate Design**

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

18 A. The Company is proposing to set the customer charge equal to the customer
19 charge that resulted from its MCCOSS which as shown in exhibit DED-9 is an increase
20 of 45 percent from the current customer charge. The Company is also proposing to
21 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.

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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.

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

3 **H. Lighting Service Rate Design**

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

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

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

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

17 **I. Other Class Rate Design Proposals**

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

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

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

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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.

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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.

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

3 • Customer charges should be increased by the system average increase, except
4 for the Residential Control Demand class which should receive a customer charge
5 increase that is equal to the one proposed by the Company.

6 • Distribution rates should be increased according to the results of my proposed
7 CCROSS with the prescribed increase allocated to the volumetric and demand components
8 on an equal percentage basis.

9 VI. Other Tariff Revisions

10 A. Residential Time of Day Pilot Program Tariff

11 Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RESIDENTIAL TIME OF 12 DAY PILOT PROGRAM TARIFF.

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

22 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.

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

6 **Q. IS THE PILOT LIMITED IN DURATION?**

7 A. Yes. The Company is proposing that the Pilot program remain open for two years
8 beginning January 1, 2019.¹³⁵ The Company states that not opening the tariff until
9 January 1, 2019 is necessary to allow additional time for the Company to develop
10 marketing material, install meters, establish other program monitoring, and sign up
11 customers to participate in the pilot.¹³⁶

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

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

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.

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

2 A. The Company provided in discovery that it used the loaded rate for a lineman with
3 truck of \$67 per hour and assumed 45 minutes for transportation and replacement of the
4 meter, which resulted in a total removal cost of \$50.25.¹³⁹ However, the Company has
5 decided to propose \$20 for the removal cost because it believes that “these revenues to
6 be very minimal but help to contribute to the costs of removal and reduce cross-
7 subsidies.”¹⁴⁰

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

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

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.

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

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

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

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

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

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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.

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

3 **Q. HOW IS THE PROPOSED GCRR DESIGNED?**

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

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

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

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

19 A. Yes. Company documents suggest that it plans on developing or purchasing
20 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.

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

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

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

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

19 A. No. The Company asserts that an investment cap is unnecessary since it is only
20 requesting the establishment of a rider, and there is no pending plan to recover any costs
21 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.

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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.

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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

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.otpc.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.

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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

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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?

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.

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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 CCOS.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 an 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 Direct Testimony of David G. Prazak, 67:6-14.

¹⁶⁹ Direct Testimony of David G. Prazak, 68:11-14.

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1 options are more efficient than the current high-intensity discharge (“HID”) technologies,
2 and LED’s have much longer lifetimes for reduced O&M expenses.¹⁷⁰

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

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

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

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

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

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.

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1 A. Yes. The Maryland Public Service Commission (“MDPSC”) and the Michigan
2 Public Service Commission (“MPSC”) have both acknowledged the importance of the
3 need for a cost analysis for street lighting customers when proposing LED tariffs. For
4 instance, the MDPSC opened a Phase II proceeding in Case No. 9217 after a number of
5 intervenors looking for more efficient lighting options found issues with the Potomac
6 Electric Power Company’s (“Pepco”) proposed revisions to its street lighting tariffs, citing
7 that the proposed revisions were excessive and based on outdated technologies.¹⁷³ The
8 Commission, in opening a Phase II proceeding, appeared to have agreed that further cost
9 analysis was necessary to set rates for the Street lighting customers and such analysis
10 should include LED fixtures as an option.¹⁷⁴ In the Phase II proceeding, Pepco filed a
11 cost of service study specific to the lighting class which identified only the costs to serve
12 its street lighting customers.¹⁷⁵ The case ultimately resulted in a Settlement Agreement
13 that was approved by the Commission. Additionally, DTE Electric Company, in its 2015
14 rate case, Case No. U-17767, proposed to “transition” customers from its experimental
15 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.

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1 failed to support the reasonableness of its revisions¹⁷⁷ and that its lighting proposal was
2 not cost based.¹⁷⁸

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

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

12 **D. Air Conditioning Rider**

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

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

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.

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

3 **Q. HOW DID THE COMPANY DETERMINE THE INCENTIVE AMOUNT?**

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

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

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

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

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

¹⁸⁰ Direct Testimony of David G. Prazak, 69:23-25.

¹⁸¹ Company's response to ND-PSC-18.31.

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1 • The Company's Residential TOD tariff revisions should be rejected since the
2 proposal is not based with any definitive evidence and relies almost exclusively on the
3 results of the Company's flawed MCCOSS. If the Commission chooses to approve the
4 proposed tariff it should require the Company to file the results of its Pilot program within
5 six months of its conclusion. I also recommend that the Commission reject the
6 Company's proposed \$20 meter removal fee since this is a pilot program and customer's
7 should not be required to pay a meter removal fee should they find that the rates are not
8 providing appropriate price signals.

9 • The Commission should reject the Company's Generation Cost Recovery Rider
10 ("GCRR") proposal since the need for this rider has not been proven. If the Commission
11 approves the GCRR, I recommend that GCRR cost recovery be limited to investments
12 associated with the Astoria Project alone and that the GCRR be subject to a sunset review
13 when the Astoria plant is moved into rate base at the time of the Company's next base
14 rate case. Additionally, I recommend that a rate cap of two percent per year be set in this
15 case for the allowed revenue requirement that can be recovered through the GRCC in
16 any year.

17 • The Company's proposed LED tariff should be approved but the current outdoor
18 lighting tariffs should remain open to all customers. No customers should be forced to
19 take LED service as proposed by the Company.

20 • The Company's Air Conditioning Rider should be expanded to include an incentive
21 for commercial customers.

22 VII. Proposed Economic Development Initiatives

23 A. Overview of Company's Proposed Economic Development Initiatives

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

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

10 **B. Test Year Economic Development Expenses**

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

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

16 **Q. WHAT IS THE BASIS FOR THIS REQUEST?**

17 A. The Company claims that its economic development efforts create expanded sales
18 opportunities and slow out-migration of retail customers from rural communities.¹⁸⁴ The
19 Company's arguments suggest that these economic development activities, presumably,
20 will prevent the negative impacts of sales attrition from arising for its remaining retail
21 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.

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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

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.

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

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

10 A. Yes. The Company spent over \$9.7 million on economic development activities
11 from 1989 to 2008.¹⁹⁶ In fact, a settlement related to the Company’s 2008 rate case would
12 have allowed \$450,000 in economic development expenses to be included for cost
13 recovery in rates.¹⁹⁷ The Commission, however, saw matters differently and ordered that
14 economic development expense provision be removed from the Settlement.¹⁹⁸ The
15 Commission was clear in noting that “the use of ratepayer dollars to fund economic
16 development projects absent evidence that the funding results in reduced rates for all
17 customers continues to be of major concern.”¹⁹⁹

18 **Q. WILL ANY PORTION OF THE COMPANY’S PLANNED ECONOMIC**
19 **DEVELOPMENT EXPENDITURES BE SUPPORTED BY SHAREHOLDER FUNDING?**

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.

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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?

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.

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

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

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

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

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

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

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.

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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.

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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

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1 **Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS**
2 **REGARDING THE COMPANY'S JCROSS.**

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

12 **Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS**
13 **REGARDING THE COMPANY'S CCROSS.**

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

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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.

PUBLIC VERSION

- 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.

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1 • The Company's proposed LED tariff should be approved but the current outdoor
2 lighting tariffs should remain open to all customers. No customers should be forced to
3 take LED service as proposed by the Company.

4 • The Company's Air Conditioning Rider should be expanded to include an incentive
5 for commercial customers.

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

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

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

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

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

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(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)
COUNTY OF East Baton Rouge) ss.

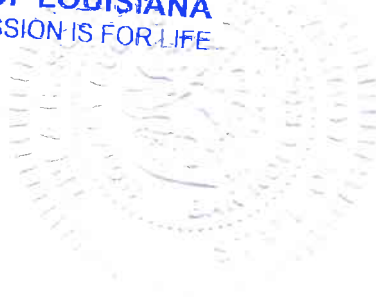
David E. Dismukes being first duly sworn on oath, deposes and states that he has read the testimony and exhibits submitted in the above captioned matter under his name, that they prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the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



DAVID E. DISMUKES, PH.D.

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2014-Current	Executive Director
2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-2014	Associate Executive Director
2001-2006	Associate Professor
1999-2001	Research Fellow and Adjunct Assistant Professor
1995-2000	Assistant Professor

College of the Coast and the Environment (Department of Environmental Studies)

2014-Current	Professor (Joint Appointment with CES)
2010-Current	Director, Coastal Marine Institute
2010-2014	Adjunct Professor

E.J. Ourso College of Business Administration (Department of Economics)

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Michigan State University, East Lansing, Michigan

2018-current Senior Fellow

Florida State University, Tallahassee, Florida

College of Social Sciences, Department of Economics

1995 Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current Consulting Economist/Principal

1995-1999 Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

1999-2001 Senior Economist

Florida Public Service Commission, Tallahassee, Florida

Division of Communications, Policy Analysis Section

1995 Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993 Planning & Research Economist

1992-1993 Economist

Project for an Energy Efficient Florida &

Florida Solar Energy Industries Association, Tallahassee, Florida

1994 Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992 Research Associate

1989-1991 Senior Research Analyst

1988-1989 Research Analyst

GOVERNMENT APPOINTMENTS

2017-Current Member, National Petroleum Council.

U.S. Department of Energy.

2007-Current Louisiana Representative, Interstate Oil and Gas Compact
Commission; Energy Resources, Research & Technology
Committee.

2007-Current Louisiana Representative, University Advisory Board
Representative; Energy Council (Center for Energy,
Environmental and Legislative Research).

2005 Member, Task Force on Energy Sector Workforce and Economic
Development (HCR 322).

2003-2005 Member, Energy and Basic Industries Task Force, Louisiana
Economic Development Council

2001-2003

Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Power System Operations and Planning in a Competitive Market.* (2002). With Fred I. Denny. New York: CRC Press.
2. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy.

PUBLICATIONS: PEER REVIEWED ACADEMIC JOURNALS

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3. "Modeling the impacts of sea-level rise, oil price, and management strategy on the costs of sustaining Mississippi delta marshes with hydraulic dredging." (2018). with Adrian R.H. Wiegman, John W. Day, Christopher F. D'Elia, Jeffrey S. Rutherford, James T. Morris, Eric D. Roy, Robert R. Lane, and Brian F. Synder. *Science of the Total Environment* 618 (2018): 1547-1559.
4. "Identifying Vulnerabilities of Working Coasts Supporting Critical Energy Infrastructure." (2016). With Siddhartha Narra. *Water*. 8(1).
5. "Economies of Scale, Learning Effects and Offshore Wind Development Costs" (2015). With Gregory B. Upton, Jr. *Renewable Energy*. 61-66.
6. "Economic impact of Gulf of Mexico ecosystem goods and services and integration into restoration decision-making." (2014) With Shepard, A.N., J.F. Valentine, C.F. D'Elia, D.W. Yoskowitz. *Gulf Science*.
7. "An Empirical Analysis of Differences in Interstate Oil and Natural Gas Drilling Activity." (2012). With Mark J. Kaiser and Christopher J. Peters. *Exploration & Production: Oil and Gas Review*. 30(1): 18-22.
8. "The Value of Lost Production from the 2004-2005 Hurricane Seasons in the Gulf of Mexico." (2009). With Mark J. Kaiser and Yunke Yu. *Journal of Business Valuation and Economic Loss Analysis*. 4(2).
9. "Estimating the Impact of Royalty Relief on Oil and Gas Production on Marginal State Leases in the US." (2006). With Jeffrey M. Burke and Dmitry V. Mesyanzhinov. *Energy Policy* 34(12): 1389-1398.
10. "Using Competitive Bidding As A Means of Securing the Best of Competitive and Regulated Worlds." (2004). With Tom Ballinger and Elizabeth A. Downer. *NRRI Journal of Applied Regulation*. 2 (November): 69-85. (Received 2005 Best Paper Award by NRRI)
11. "Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes." (2004). With K.E. Hughes II. *International Energy Law and Taxation Review*. 10 (October): 206-212.

12. "Reflections on the U.S. Electric Power Production Industry: Precedent Decisions Vs. Market Pressures." (2003). With Robert F. Cope III and John W. Yeargain. *Journal of Legal, Ethical, and Regulatory Issues*. Volume 6, Number 1.
13. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001) *Public Resources Law Digest*. 38: 2.
14. "A Comment on the Integration of Price Cap and Yardstick Competition Schemes in Electrical Distribution Regulation." (2001). With Steven A. Ostrover. *IEEE Transactions on Power Systems*. 16 (4): 940 -942.
15. "Modeling Regional Power Markets and Market Power." (2001). With Robert F. Cope. *Managerial and Decision Economics*. 22:411-429.
16. "A Data Envelopment Analysis of Levels and Sources of Coal Fired Electric Power Generation Inefficiency" (2000). With Williams O. Olatubi. *Utilities Policy*. 9 (2): 47-59.
17. "Cogeneration and Electric Power Industry Restructuring" (1999). With Andrew N. Kleit. *Resource and Energy Economics*. 21:153-166.
18. "Capacity and Economies of Scale in Electric Power Transmission" (1999). With Robert F. Cope and Dmitry Mesyanzhinov. *Utilities Policy* 7: 155-162.
19. "Oil Spills, Workplace Safety, and Firm Size: Evidence from the U.S. Gulf of Mexico OCS." (1997). With O. O. Iledare, A. G. Pulsipher, and Dmitry Mesyanzhinov. *Energy Journal* 4: 73-90.
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1. "Hydraulic Fracturing: A Look at Efficiency and the Environmental Effects of Fracking" (2014). With Emily C. Jackson. *Environmental Science and Technology: Proceedings from the 7th International Conference on Environmental Science and Technology*. Volume 1 of 2: edited by George A. Sorial and Jihua Hong. (Houston, TX: American Science Press, ISBN: 978-0976885368): 42-46.
2. "Economic and Policy Issues in Sustaining an Adequate Oil Spill Contingency Fund in the Aftermath of a Catastrophic Incident." (2014). With Stephen R. Barnes and Gregory B. Upton. *Proceedings of the Thirty-seventh AMOP Technical Seminar on Environmental contamination and Response*. June: 506-524.
3. "Technology Based Ethical Issues Surrounding the California Energy Crisis." (2002). With Robert F. Cope III and John Yeargain. *Proceedings of the Academy of Legal, Ethical, and Regulatory Issues*. September: 17-21.
4. "Electric Utility Restructuring and Strategies for the Future." (2001). With Scott W. Geiger. *Proceedings of the Southwest Academy of Management*. March.
5. "Applications for Distributed Energy Resources in Oil and Gas Production: Methods for Reducing Flare Gas Emissions and Increasing Generation Availability" (2000). With

- Ritchie D. Priddy. *Proceedings of the International Energy Foundation – ENERGEX 2000*. July.
6. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry" (1998). With Fred I. Denny. *IEEE Proceedings: Large Engineering Systems Conference on Power Engineering*. June: 294-298.
 7. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. *Proceedings of the International Association of Science and Technology for Development*. October: 499-504.
 8. "Safety Regulations, Firm Size, and the Risk of Accidents in E&P Operations on the Gulf of Mexico Outer Continental Shelf" (1996). With Allan Pulsipher, Omowumi Iledare, and Bob Baumann. *Proceedings of the American Society of Petroleum Engineers: Third International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production*, June.
 9. "Comparing the Safety and Environmental Records of Firms Operating Offshore Platforms in the Gulf of Mexico." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the American Society of Mechanical Engineers: Offshore and Arctic Operations 1996*, January.

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1. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements" (2005). *Proceedings of the 23rd Annual Information Technology Meetings*. U.S. Department of the Interior, Minerals Management Service, Gulf Coast Region, New Orleans, LA. January 12, 2005.
2. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) *Proceedings of the 51st Mineral Law Institute*, Louisiana State University, Baton Rouge, LA. April 2, 2004.
3. "Competitive Bidding in the Electric Power Industry." (2003). *Proceedings of the Association of Energy Engineers*. December 2003.
4. "The Role of ANS Gas on Southcentral Alaskan Development." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: Energy Markets in Turmoil: Making Sense of It All*. October.
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3. "Competitive Power Procurement An Appropriate Strategy in a Quasi-Regulated World." (2004). In *Electric and Natural Gas Business: Using New Strategies, Understanding the Issues*. With Elizabeth A. Downer. Edited by Robert Willett. Houston, TX: Financial Communications Company, 91-104.
4. "Alaskan North Slope Natural Gas Development." (2003). In *Natural Gas and Electric Industries Analysis 2003*. With William E. Nebesky, Dmitry Mesyanzhinov, and Jeffrey M. Burke. Edited by Robert Willett. Houston, TX: Financial Communications Company, 185-205.
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7. "Electric Power Generation." (2000). In the *Macmillan Encyclopedia of Energy*. Edited by John Zumerchik. New York: Macmillan Reference.

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1. Review of ***Renewable Resources for Electric Power: Prospects and Challenges***. Raphael Edinger and Sanjay Kaul. (Westport, Connecticut: Quorum Books, 2000), pp 154. ISBN 1-56720-233-0. *Natural Resources Forum*. (2000).
2. Review of ***Electricity Transmission Pricing and Technology***, edited by Michael Einhorn and Riaz Siddiqi. (Boston: Kluwer Academic Publishers, 1996) pp. 282. ISBN 0-7923-9643-X. *Energy Journal* 18 (1997): 146-148.
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2. "Unconventional Natural Gas and the U.S. Manufacturing Renaissance" (2013). *BIC Magazine*. Vol. 30: No. 2, p. 76 (March).
3. "Louisiana's Tuscaloosa Marine Shale Development: Emerging Resource and Economic Potentials" (2012). *Spectrum*. January-April: 18-20.
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6. "Model Framework Can Aid Decision on Redevelopment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.26: 49-53 (July 14) (part 2 of 3).
7. "Field Redevelopment Economics and Storm Impact Assessment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.25: 42-50 (July 7) (part 1 of 3).
8. "The IRS' Latest Proposal on Tax Normalization: A Pyrrhic Victory for Ratepayers," (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 55(1): 217-236
9. "Executive Compensation in the Electric Power Industry: Is It Excessive?" (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(4): 913-940.
10. "Renewable Portfolio Standards in the Electric Power Industry." With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(3): 693-706.
11. "Regulating Mercury Emissions from Electric Utilities: Good Environmental Stewardship or Bad Public Policy? (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54 (2): 401-424

12. "Using Industrial-Only Retail Choice as a Means of Moving Competition Forward in the Electric Power Industry." (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(1): 211-223
13. "The Nuclear Power Plant Endgame: Decommissioning and Permanent Waste Storage." (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (4): 981-997
14. "Can LNG Preserve the Gas-Power Convergence?" (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (3):783-796.
15. "Competitive Bidding as a Means of Securing Opportunities for Efficiency." (2004). With Elizabeth A. Downer. *Electricity and Natural Gas* 21 (4): 15-21.
16. "The Evolving Markets for Polluting Emissions: From Sulfur Dioxide to Carbon Dioxide." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53(2): 479-494.
17. "The Challenges Associated with a Nuclear Power Revival: Its Past." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (1): 193-211.
18. "Deregulation of Generating Assets and The Disposition of Excess Deferred Federal Income Taxes: A 'Catch-22' for Ratepayers." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 873-891.
19. "Will Competitive Bidding Make a Comeback?" (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 659-674
20. "An Electric Utility's Exposure to Future Environmental Costs: Does It Matter? You Bet!" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 457-469.
21. "White Paper or White Flag: Do FERC's Concessions Represent A Withdrawal from Wholesale Power Market Reform?" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 197-207.
22. "Clear Skies" or Storm Clouds Ahead? The Continuing Debate over Air Pollution and Climate Change" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 823-848.
23. "Economic Displacement Opportunities in Southeastern Power Markets." (2003). With Dmitry V. Mesyanzhinov. *USAAE Dialogue*. 11: 20-24.
24. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 635-652.
25. "Is There a Role for the TVA in Post-Restructured Electric Markets?" (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 433-454.
26. "The Role of Alaska North Slope Gas in the Southcentral Alaska Regional Energy Balance." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Natural Gas Journal*. 19: 10-15.
27. "Standardizing Wholesale Markets For Energy." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 207-225.
28. "Do Economic Activities Create Different Economic Impacts to Communities Surrounding the Gulf OCS?" (2002). With Williams O. Olatubi. *IAEE Newsletter*. Second Quarter: 16-20.
29. "Will Electric Restructuring Ever Get Back on Track? Texas is not California." (2002). With

- K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50: 943-960.
30. "An Assessment of the Role and Importance of Power Marketers." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50: 713-731.
 31. "The EPA v. The TVA, et. al. Over New Source Review." (2001) With K.E. Hughes, II. *Oil, Gas and Energy Quarterly*. 50:531-543.
 32. "Energy Policy by Crisis: Proposed Federal Changes for the Electric Power Industry." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50:235-249.
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 38. "The Post-Restructuring Consolidation of Nuclear-Power Generation in the Electric Power Industry." (2000) With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 751-765.
 39. "Issues and Opportunities for Small Scale Electricity Production in the Oil Patch." (2000). With Ritchie D. Priddy. *American Oil and Gas Reporter*. 49: 78-82.
 40. "Distributed Energy Resources: The Next Paradigm Shift in the Electric Power Industry." (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 48:593-602.
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 44. "Reliability or profit? Why Entergy quit the Southwest Power Pool." (1998). With Fred I. Denny. *Public Utilities Fortnightly*. February 1: 30-33.
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5. "Reading the tea leaves for 2017's crude oil markets." (2017). *10/12 Industry Report*. Baton Rouge Business Report. Q:1.
6. "The unappreciated role of energy infrastructure." (2016). *10/12 Industry Report*. Baton Rouge Business Report. Q:4.
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10. Challenging Times for the South Louisiana Energy Economy. (2016). *10/12 Industry Report*. Baton Rouge Business Report. Q:1.
11. "Reading the Signs for the Energy Complex" (2015). *10/12 Industry Report*. Baton Rouge Business Report. Q:1.
12. "Louisiana's Export Opportunities." (2015). *10/12 Industry Report*. Baton Rouge Business Report. September, 15.
13. "Don't Kill Hydraulic Fracturing: It's the Golden Goose." (2015). *Mobile Press Register*. May 22. Also carried by Alabama Media Group and the following newspapers: *Birmingham News*, *Huntsville Times*, and *Birmingham Magazine*.
14. "The Least Effective Way to Invest in Green Energy." (2014). *Wall Street Journal*. Journal Reports: Energy. New York: Dow Jones & Company, October 2.
15. "Stop Picking Winners and Losers." (2013). *Wall Street Journal*. Journal Reports: Energy. New York: Dow Jones & Company, June 18.

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1. *MISO Grid 2033: Preparing for the Transmission Grid of the Future*. (2018). Baton Rouge, LA: LSU Center for Energy Studies, May 7, 87 pp.
2. *Opportunities and challenges in using industrial CHP as a resiliency measure in Louisiana*. (2017). Baton Rouge, LA: Louisiana Department of Natural Resources, December 17, 52 pp.
3. *Efficiency and emissions reduction opportunities at existing Louisiana combined heat and power applications*. (2017). Baton Rouge, LA: Louisiana Department of Natural Resources, December 17, 44 pp.
4. *Louisiana industrial combined heat and power applications: status and operations*. (2017). Baton Rouge, LA: Louisiana Department of Natural Resources, December 17, pp. 54.
5. *The potential economic impacts of the Washington Parish Energy Center*. (2017). With

- Gregory B. Upton, Jr. Report prepared on behalf of Calpine Corporation. 5 pp.
6. *Economic impact and re-employment assessment of PES Philadelphia refining complex.* (2017). Report prepared on the behalf of Philadelphia Energy Solutions. August 31, 43 pp.
 7. *The potential economic impacts of the Bayou Bridge Project.* (2017). With Gregory B. Upton, Jr. Report prepared on behalf of Energy Transfer, LLC. 23 pp.
 8. *Gulf Coast energy outlook (2017).* With Christopher Coombs, Dek Terrell, and Gregory B. Upton. Center for Energy Studies/Applied Economics Group, 18 pp.
 9. *Potential economic impacts of the Lake Charles methanol project.* (2017). Report prepared on behalf of the Lake Charles Methanol Project, LLC. 68 pp.
 10. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers.* (2015). Louisiana Public Service Commission, *In re: Examination of the Comprehensive Costs and Benefits of Net Metering in Louisiana*, Docket No. X-33192. Notice of Issuance of Final Report dated September 11, 2015, 187 pp.
 11. *Beyond the Energy Roadmap: Starting Mississippi's Energy-Based Economic Development Venture.* (2014). Report prepared on behalf of the Mississippi Energy Institute, 310 pp.
 12. *Combined Heat and Power in Louisiana: Status, Potentials, and Policies.* Phase 4 Report: *Policy and Market Opportunities and Challenges for CHP Development.* (2013). Louisiana Department of Natural Resources, Baton Rouge, Louisiana. 17 pp.
 13. *Combined Heat and Power in Louisiana: Status, Potentials, and Policies.* Phase 3 Report: *Empirical Results, Technical and Cost-Effectiveness Potentials.* (2013). Louisiana Department of Natural Resources, Baton Rouge, Louisiana. 65 pp.
 14. *Combined Heat and Power in Louisiana: Status, Potentials, and Policies.* Phase 2 Report: *Technical and Cost Effectiveness Methodologies.* (2013). Louisiana Department of Natural Resources, Baton Rouge, Louisiana. 39 pp.
 15. *Combined Heat and Power in Louisiana: Status, Potentials, and Policies.* Phase 1 Report: *Resource Characterization and Database.* (2013). Louisiana Department of Natural Resources, Baton Rouge, Louisiana. 62 pp.
 16. *Onshore Oil and Gas Infrastructure to Support Development in the Mid-Atlantic OCS Region.* (2014). U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico OCS Region, New Orleans, LA. OCS Study BOEM 2014-657. 360 pp.
 17. *Unconventional Resources and Louisiana's Manufacturing Development Renaissance* (2013). Baton Rouge, LA: LSU Center for Energy Studies, 93 pp.
 18. *Removing Big Wind's "Training Wheels:" The Case for Ending the Production Tax Credit* (2012). Washington, DC: American Energy Alliance, 19 pp.
 19. *The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana.* (2012). Baton Rouge, LA: LSU Center for Energy Studies, 62 pp.
 20. *Diversifying Energy Industry Risk in the GOM: Post-2004 Changes in Offshore Oil and Gas Insurance Markets.* (2011) With Christopher P. Peters. U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region, New Orleans, LA. OCS Study BOEM 2011-054. 95pp.

21. *OCS-Related Infrastructure Fact Book. Volume I: Post-Hurricane Impact Assessment.* (2011). U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region, New Orleans, LA. OCS Study BOEM 2011-043. 372 pp.
22. *Fact Book: Offshore Oil and Gas Industry Support Sectors.* (2010). U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region, New Orleans, LA. OCS Study BOEM 2010-042. 138pp.
23. *The Impacts of Greenhouse Gas Regulation on the Louisiana Economy.* (2011). With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, and Lauren L. Stuart. Louisiana Greenhouse Gas Inventory Project, Task 3 and 4 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 134 pp.
24. *Overview of States' Climate Action and/or Alternative Energy Policy Measures.* (2010). With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, and Lauren L. Stuart. Louisiana Greenhouse Gas Inventory Project, Task 2 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 30 pp.
25. *Louisiana Greenhouse Gas Inventory.* (2010). With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, Lauren L. Stuart, and Jordan L. Gilmore. Louisiana Greenhouse Gas Inventory Project, Task 1 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 114 pp.
26. *Opportunities for Geo-pressured Thermal Energy in Southwestern Louisiana.* (2010). Report prepared on behalf of Louisiana Geothermal, L.L.C, 41 pp.
27. *Economic and Energy Market Benefits of the Proposed Cavern Expansions at the Jefferson Island Storage and Hub Facility.* (2009). Report prepared on behalf of Jefferson Island Storage and Hub, LLC, 28 pp.
28. *The Benefits of Continued and Expanded Investments in the Port of Venice.* (2009). With Christopher Peters and Kathryn Perry. Baton Rouge, LA: LSU Center for Energy Studies. 83 pp.
29. *Examination of the Development of Liquefied Natural Gas on the Gulf of Mexico.* (2008). U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA OCS Study MMS 2008-017. 106 pp.
30. *Gulf of Mexico OCS Oil and Gas Scenario Examination: Onshore Waste Disposal.* (2007). With Michelle Barnett, Derek Vitrano, and Kristen Strellec. OCS Report, MMS 2007-051. New Orleans, LA: U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico Region.
31. *Economic Impact Analysis of the Proposed Lake Charles Gasification Project.* (2007). Report Prepared on Behalf of Leucadia Corporation.
32. *The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard.* (2005) Report Prepared on Behalf of the New Jersey Division of Ratepayer Advocate.
33. *The Importance of Energy Production and Infrastructure in Plaquemines Parish.* (2006). Report Prepared on Behalf of Project Rebuild Plaquemines.
34. *Louisiana's Oil and Gas Industry: A Study of the Recent Deterioration in-State Drilling Activity.* (2005). With Kristi A.R. Darby, Jeffrey M. Burke, and Robert H. Baumann. Baton

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35. *Comparison of Methods for Estimating the NO_x Emission Impacts of Energy Efficiency and Renewable Energy Projects Shreveport, Louisiana Case Study*. (2005). With Adam Chambers, David Kline, Laura Vimmerstedt, Art Diem, and Dmitry Mesyanzhinov. Golden, Colorado: National Renewable Energy Laboratory.
36. *Economic Opportunities for a Limited Industrial Retail Choice Plan in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana State University Center for Energy Studies.
37. *Economic Opportunities for LNG Development in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana Department of Economic Development and Greater New Orleans, Inc.
38. *Marginal Oil and Gas Production in Louisiana: An Empirical Examination of State Activities and Policy Mechanisms for Stimulating Additional Production*. (2004). With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.
39. *Deepwater Program: OCS-Related Infrastructure in the Gulf of Mexico Fact Book*. (2004). With Louis Berger Associates, University of New Orleans National Ports and Waterways Institute, and Research and Planning Associates. MMS Study No. 1435-01-99-CT-30955. U.S. Department of the Interior, Minerals Management Service.
40. *The Power of Generation: The Ongoing Benefits of Independent Power Development in Louisiana*. With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, and Elizabeth A. Downer. Baton Rouge, LA: LSU Center for Energy Studies, 2003.
41. *Modeling the Economic Impact of Offshore Oil and Gas Activities in the Gulf of Mexico: Methods and Application*. (2003). With Williams O. Olatubi, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Prepared by the Center for Energy Studies, Louisiana State University, Baton Rouge, LA. OCS Study MMS2000-0XX. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA.
42. *An Analysis of the Economic Impacts Associated with Oil and Gas Activities on State Leases*. (2002) With Robert H. Baumann, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.
43. *Alaska In-State Natural Gas Demand Study*. (2002). With Dmitry Mesyanzhinov, et.al. Anchorage, Alaska: Alaska Department of Natural Resources, Division of Oil and Gas.
44. *Moving to the Front of the Lines: The Economic Impacts of Independent Power Plant Development in Louisiana*. (2001). With Dmitry Mesyanzhinov and Williams O. Olatubi. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.
45. *The Economic Impacts of Merchant Power Plant Development in Mississippi*. (2001). Report Prepared on Behalf of the US Oil and Gas Association, Alabama and Mississippi Division. Houston, TX: Econ One Research, Inc.
46. *Energy Conservation and Electric Restructuring in Louisiana*. (2000). With Dmitry Mesyanzhinov, Ritchie D. Priddy, Robert F. Cope III, and Vera Tabakova. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.
47. *Assessing the Environmental and Safety Risks of the Expanded Role of Independents in*

- Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS.* (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.
48. *Restructuring the Electric Utility Industry: Implications for Louisiana.* (1996). With Allan Pulsipher and Kimberly H. Dismukes. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

GRANT RESEARCH

1. *Co-investigator.* Estimating offshore Gulf of Mexico carbon capture, sequestration, and utilization opportunities. (2018). With Southern States Energy Board, Advanced Resources International, Argonne Laboratories, University of Alabama, University of South Carolina, and Oklahoma State University. U.S. Department of Energy, National Energy Technology Laboratory. \$731,031 (LSU share of \$4.0 million project, three years, in progress).
2. *Principal Investigator.* Understanding MISO long term infrastructure needs and stakeholder positions. (2017). Midcontinent Independent System Operator. Total Project: \$9,500, six months. Status: In Progress.
3. *Principal Investigator.* Offshore oil and gas activity impacts on ecosystem services in the Gulf of Mexico. (2017) With Brian F. Snyder. U.S. Department of the Interior, Bureau of Ocean Energy Management. Total Project: \$240,982, two years. Status: In Progress.
4. *Principal Investigator.* Economic Impacts of the Bayou Bridge pipeline. (2017). With Gregory B. Upton, Jr., Energy Transfer Corporation. \$9,900. Status: Completed.
5. *Principal Investigator.* Integrated carbon capture, storage and utilization in the Louisiana chemical corridor. (2017). U.S. Department of Energy/National Energy Technology Laboratory. Total funding: \$1,300,000 (18 months). Status: In progress
6. *Co-Principal Investigator.* Gulf coast energy outlook and analysis. (2016). With Gregory B. Upton and Mallory Vachon. Regions Bank. Total funding: \$20,000, one year. Status: Completed.
7. *Principal Investigator.* GOM energy infrastructure trends and factbook update. (2016). With Gregory B. Upton and Mallory Vachon. U.S. Department of the Interior, Bureau of Ocean Energy Management ("BOEM"). Total funding: \$224,995, two years. Status: In progress.
8. *Principal Investigator.* Examining Louisiana's Industrial Carbon Sequestration Potential. Phase 2: Follow-up and estimation. (2016). With Brian F. Snyder. Southern States Energy Board. Total Project: \$69,990, three months. Status: Completed.
9. *Principal Investigator.* Examining Louisiana's Industrial Carbon Sequestration Potential. Phase 1: Scoping and Identification. (2016). With Brian F. Snyder. Southern States Energy Board. Total Project: \$29,919, three months. Status: Completed.
10. *Principal Investigator.* Energy efficiency building codes for Louisiana. (2016). With Brian F. Snyder. Louisiana Department of Natural Resources. Total Project: \$50,000, one year. Status: Completed.
11. *Principal Investigator.* An update of Louisiana's combined heat and power potentials, current utilizations, and barriers to improved operating efficiencies. (2016). Louisiana

- Department of Natural Resources. Total Project: \$90,000, one year. Status: Completed.
12. *Principal Investigator*. Combined Heat and Power Stakeholder Meeting. (2016). Southeastern Energy Efficiency Council. Total Project \$9,160, two months. Status: Completed.
 13. *Co-Investigator*. "Expanding Ecosystem Service Provisioning from Coastal Restoration to Minimize Environmental and Energy Constraints" (2015). With John Day and Chris D'Elia. Gulf Research Program. Total Project: \$147,937. Status: Completed.
 14. *Principal Investigator*. "Coastal Marine Institute Administrative Grant" (2104). U.S. Department of the Interior. Total Project \$45,000. Status: Completed.
 15. *Principal Investigator*. "Analysis of the Potential for Combined Heat and Power (CHP) in Louisiana." (2013). Louisiana Department of Natural Resources. Total Project: \$90,000. Status: Completed.
 16. *Co-Investigator*. "CNH: A Tale of Two Louisianas: Coupled Natural-Human Dynamics in a Vulnerable Coastal System" (2013) With Nina Lam, Margaret Reams, Kam-Biu Liu, Victor Rivera, and Kelley Pace. National Science Foundation. Total Project: \$1.5 million. Status: In Progress (Sept 2012-Feb 2017).
 17. *Principal Investigator*. "Examination of Unconventional Natural Gas and Industrial Economic Development" (2012). America's Natural Gas Alliance. Total Project: \$48,210. Status: Completed.
 18. *Principal Investigator*. "Investigation of the Potential Economic Impacts Associated with Shell's Proposed Gas-To-Liquids Project" (2012). Shell Oil Company, North America. Total Project: \$76,708. Status: Completed.
 19. *Principal Investigator*. "Analysis of the Federal Wind Energy Production Tax Credit." American Energy Alliance. Total Project: \$20,000. Status: Completed.
 20. *Principal Investigator*. "Energy Sector Impacts Associated with the Deepwater Horizon Oil Spill." Louisiana Department of Economic Development. Total Project: approximately \$50,000. Status: Completed.
 21. *Principal Investigator*. "Economic Contributions and Benefits Support by the Port of Venice." Port of Venice Coalition. Total Project: \$20,000. Status: Completed.
 22. *Principal Investigator*. "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: \$150,000. Status: Completed.
 23. *Principal Investigator*. "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: \$98,543. Status: Completed.
 24. *Principal Investigator*. "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: \$377,917 (3 years). Status: Completed.
 25. *Principal Investigator*. "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: \$241,216 (2.5 years). Status: Completed.

26. *Principal Investigator.* "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: \$169,906. (one year). Status: Completed.
27. *Principal Investigator.* "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: \$78,374 (one year). Status: Awarded, In Progress.
28. *Principal Investigator.* "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: \$18,267. Status: Completed.
29. *Principal Investigator.* "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: \$65,302 (two years). Status: Awarded, In Progress.
30. *Principal Investigator.* "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: \$244,837. Status: In Progress.
31. *Principal Investigator.* "Ultra-Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: \$15,000. Status: Completed.
32. *Principal Investigator.* "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: \$75,000. Status: Completed.
33. *Principal Investigator.* "An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding \$101,054. Status: Completed.
34. *Principal Investigator.* "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: \$37,000. Status: Completed.
35. *Principal Investigator.* "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: \$25,000. Status: Completed.
36. *Principal Investigator.* "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: \$72,000. Status: Completed.
37. *Principal Investigator.* "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and

- Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: \$557,744. Status: Awarded, In Progress.
38. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: \$8,000. Status: Completed.
 39. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: \$244,956. Status: Completed.
 40. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: \$190,166. Status: Completed.
 41. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: \$43,169. Status: Completed.
 42. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: \$19,948. Status: Completed.
 43. *Co-Principal Investigator*. "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: \$109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "The changing nature of Gulf of Mexico energy infrastructure." (2017). Session 3B: New Directions in Social Science Research. 27th Gulf of Mexico Region Information Technology Meetings. U.S. Department of the Interior, Bureau of Ocean Energy Management, Environmental Studies Program. New Orleans, LA. August 24.
2. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). U.S. Department of Energy, 2017 Industrial Energy Technology Conference, New Orleans, LA June 21.
3. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). With Gregory Upton. Southern Economic Association Meeting 2015. New Orleans, Louisiana. November 23.
4. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks" (2015). With Gregory Upton. 38th IAEE International Conference, Antalya, Turkey. May 26.
5. "Modifying Renewables Policies to Sustain Positive Economic and Environmental Change" (2015). IEEE Annual Green Technologies ("Greentech") Conference. April 17.

6. "The Gulf Coast Industrial Investment Renaissance and New CHP Development Opportunities." (2014). Industrial Energy and Technology Conference, New Orleans, Louisiana. May 20.
7. "Estimating Critical Energy Infrastructure Value at Risk from Coastal Erosion" (2014). With Siddhartha Narra. American's Estuaries: 7th Annual Summit on Coastal and Estuarine Habitat Restoration. Washington, D.C., November 3-6.
8. "Economies of Scale, Learning Curves, and Offshore Wind Development Costs" (2012). With Gregory Upton. Southern Economic Association Annual Conference, New Orleans, LA November 17.
9. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7.
10. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.
11. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.
12. "Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure." (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7.
13. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19.
14. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16.
15. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.
16. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). U.S. Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.
17. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.
18. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.
19. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Arctic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

20. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.
21. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).
22. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).
23. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.
24. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.
25. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.
26. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.
27. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.
28. "Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring." (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.
29. "Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach." (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.
30. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.
31. "Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation." (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.
32. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

33. "Modeling Regional Power Markets and Market Power." (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.
34. "Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana" (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.
35. "Empirical Issues in Electric Power Transmission and Distribution Cost Modeling." (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.
36. "Modeling Electric Power Markets in a Restructured Environment." (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.
37. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.
38. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.
39. "Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.
40. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.
41. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30
42. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.
43. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.
44. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.
45. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

46. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.
47. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.
48. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.
49. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.
50. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.
51. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. "Air Emissions Regulation and Policy: The Recently Proposed Cross State Air Pollution Rule and the Implications for Louisiana Power Generation." Lecture before School of the Coast & Environment. November 5, 2011.
2. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.
3. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.
4. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.
5. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.
6. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.
7. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNeese State University. Lake Charles, Louisiana. May 2, 2001.
8. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.
9. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

10. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Infrastructure and capacity: challenges for development." (2018). Society of Utility and Regulatory Financial Analysts (SURFA) Annual Meeting, New Orleans, LA, April 20.
2. "Louisiana industrial cogeneration trends." (2018). Annual Louisiana Solid Waste Association Conference, Lafayette, LA, March 16.
3. "Gulf Coast industrial development: overview of trends and issues." (2018). Gulf Coast Power Association Meetings, New Orleans, LA, February 8.
4. "Energy outlook – reflection on market trends and Louisiana implications." (2017). IberiaBank Corporation Bank Board of Directors Meeting, New Orleans, LA. November 15.
5. "Integrated Carbon Capture and Storage in the Louisiana Chemical Corridor." (2017). Industry Associates Advisory Council Meeting, Baton Rouge, LA. November 7.
6. "The outlook for natural gas and energy development on the Gulf Coast." (2017). Louisiana Chemical Association, Annual Meeting, New Orleans, LA. October 26.
7. "Critical energy infrastructure: the big picture on resiliency research." (2017). National Academies of Science, Engineering, and Medicine. New Orleans, LA. September 18.
8. "The changing nature of Gulf of Mexico energy infrastructure." (2017). 27th Gulf of Mexico Region Information Technology Meetings, New Orleans, LA, August 24.
9. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). Industrial Energy Technology Conference, New Orleans, LA. June 21.
10. "Crude oil and natural gas outlook: Where are we and where are we going?" (2017). CCREDC Economic Trends Panel. Corpus Christi, TX, June 15.
11. "Navigating through the energy landscape." (2017). Baton Rouge Rotary Luncheon. Baton Rouge, LA, May 24.
12. "The 2017-2018 Louisiana energy outlook." (2017). Junior Achievement of Greater New Orleans, JA BizTown Speaker Series. New Orleans, LA, May 12.
13. "The Gulf Coast energy economy: trends and outlook." (2017). Society for Municipal Analysts. New Orleans, LA, April 21.
14. "Recent trends in energy: overview and impact for the banking community." (2017). Oil and Gas Industry Update, Louisiana Bankers Association. Baton Rouge, LA, March 24.
15. "How supply, demand and prices have influenced unconventional development." (2016). Energy Annual Meeting, CLEER-University Advisory Board Lecture. New Orleans, LA, September 17.
16. "The Basics of Natural Gas Production, Transportation, and Markets." (2016). Center for Energy Studies. Baton Rouge, LA, August 1.

17. "Gulf Coast industrial development: trends and outlook." (2016). Investor Relations Group Meeting, Edison Electric Institute. New Orleans, LA, June 23.
18. "The future of policy and regulation: Unlocking the Treasures of Utility Regulation." (2016). Annual Meeting, National Conference of Regulatory Attorneys. Tampa, FL, June 20.
19. "Utility mergers: where's the beef?". (2016). National Association of State Utility Consumer Advocates Mid-Year Meetings. New Orleans, LA, June 6.
20. "Overview of the Clean Power Plan and its application to Louisiana." (2016). Shell Oil Company Internal Meeting. April 12.
21. "Energy and economic development on the Gulf Coast: trends and emerging challenges." (2016). Gas Processors Association Meeting. New Orleans, LA, April 11.
22. "Unconventional Oil and Gas Drilling Trends and Issues." (2016). French Delegation Visit, LSU Center for Energy Studies. March 16.
23. "Gulf Coast Industrial Growth: Passing clouds or storms on the horizon?" (2016). Gulf Coast Power Association Meetings. New Orleans, LA, February 18.
24. "The Transition to Crisis: What do the recent changes in energy markets mean for Louisiana?" (2016). Louisiana Independent Study Group. February 2.
25. "Regulatory and Ratepayer Issues in the Analysis of Utility Natural Gas Reserves Purchases" (2016). National Association of State Utility Consumer Advocates Gas Consumer Monthly Meeting. January 25.
26. "Emerging Issues in Fuel Procurement: Opportunities & Challenges in Natural Gas Reserves Investment." (2015). National Association of State Utility Consumer Advocates Annual Meeting. Austin, Texas. November 9.
27. "Trends and Issues in Net Metering and Solar Generation." (2015). Louisiana Rural Electric Cooperative Meeting. November 5.
28. "Electric Power: Industry Overview, Organization, and Federal/State Distinctions." (2015). EUCI. October 16.
29. "Natural Gas 101: The Basics of Natural Gas Production, Transportation, and Markets." (2015). Council of State Governments Special Meeting on Gas Markets. New Orleans, LA. October 14.
30. "Update and General Business Matters." (2015). CES Industry Associates Meeting. Baton Rouge, Louisiana. Fall 2015.
31. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). 38th IAEE 2015 International Conference. Antalya, Turkey. May 26.
32. "Industry on the Move – What's Next?" (2015). Event Sponsored by Regional Bank and 1012 Industry Report. May 5.
33. "The State of the Energy Industry and Other Emerging Issues." (2015). Lex Mundi Energy & Natural Resources Practice Group Global Meeting. May 5.
34. "Energy, Louisiana, and LSU." (2015). LSU Science Café. Baton Rouge, Louisiana. April 28.
35. "Energy Market Changes and Impacts for Louisiana." (2015). Kinetica Partners Shippers

- Meeting, New Orleans, Louisiana. April 22.
36. "Incentives, Risk and the Changing Nature of Utility Regulation." (2015). NARUC Staff Subcommittee on Accounting and Finance Meetings, New Orleans, Louisiana. April 22.
 37. "Modifying Renewables Policies to Sustain Positive and Economic Change." (2015). IEEE Annual Green Technologies ("Greentech Conference"). April 17.
 38. "Louisiana's Changing Energy Environment." (2015). John P. Laborde Energy Law Center Advisory Board Spring Meeting, Baton Rouge, Louisiana. March 27.
 39. "The Latest and the Long on Energy: Outlooks and Implications for Louisiana." (2015). Iberia Bank Advisory Board Meeting, Baton Rouge, Louisiana. February 23.
 40. "A Survey of Recent Energy Market Changes and their Potential Implications for Louisiana." (2015). Vistage Group, New Orleans, Louisiana. February 4.
 41. "Energy Prices and the Outlook for the Tuscaloosa Marine Shale." (2015). Baton Rouge Rotary Club, Baton Rouge, Louisiana. January 28.
 42. "Trends in Energy & Energy-Related Economic Development." (2014). Miller and Thompson Presentation, Baton Rouge, Louisiana. December 30.
 43. "Overview EPA's Proposed Rule Under Section 111(d) of the Clean Air Act: Impacts for Louisiana." (2014). Louisiana State Bar: Utility Section CLE Annual Meeting, Baton Rouge, Louisiana. November 7.
 44. "Overview EPA's Proposed Clean Power Plan and Impacts for Louisiana." (2014). Clean Cities Coalition Meeting, Baton Rouge, Louisiana. November 5.
 45. "Impacts on Louisiana from EPA's Proposed Clean Power Plan." (2014). Air & Waste Management Annual Environmental Conference (Louisiana Chapter), Baton Rouge, Louisiana. October 29, 2014.
 46. "A Look at America's Growing Demand for Natural Gas." (2014). Louisiana Chemical Association Annual Meeting, New Orleans, Louisiana. October 23.
 47. "Trends in Energy & Energy-Related Economic Development." (2014). 2014 Government Finance Officer Association Meetings, Baton Rouge, Louisiana. October 9.
 48. "The Conventional Wisdom Associated with Unconventional Resource Development." (2014). National Association for Business Economics Annual Conference, Chicago, Illinois. September 28.
 49. Unconventional Oil & Natural Gas: Overview of Resources, Economics & Policy Issues. (2014). Society of Environmental Journalists Annual Meeting. New Orleans, Louisiana. September 4.
 50. "Natural Gas Leveraged Economic Development in the South." (2014). Southern Governors Association Meeting, Little Rock, Arkansas. August 16.
 51. "The Past, Present and Future of CHP Development in Louisiana." (2014). Louisiana Public Service Commission CHP Workshop, Baton Rouge, Louisiana. June 25.
 52. "Regional Natural Gas Demand Growth: Industrial and Power Generation Trends." (2014). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 30.
 53. "The Technical and Economic Potential for CHP in Louisiana and the Impact of the

- Industrial Investment Renaissance on New CHP Capacity Development.” (2014). Electric Power 2014, New Orleans, Louisiana. April 1.
54. “Industry Investments and the Economic Development of Unconventional Development.” (2014). Tuscaloosa Marine Shale Conference & Expo, Natchez, Mississippi. March 31.
 55. Discussion Panelist. Energy Outlook 2035: The Global Energy Industry and Its Impact on Louisiana, (2014). Grow Louisiana Coalition, Baton Rouge, Louisiana. March 18.
 56. “Natural Gas and the Polar Vortex: Has Recent Weather Led to a Structural Change in Natural Gas Markets?” (2014). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. February 19.
 57. “Some Unconventional Thoughts on Regional Unconventional Gas and Power Generation Requirements.” (2014). Gulf Coast Power Association Special Briefing, New Orleans, Louisiana. February 6.
 58. “Leveraging Energy for Industrial Development.” (2013). 2013 Governor’s Energy Summit, Jackson, Mississippi. December 5.
 59. “Natural Gas Line Extension Policies: Ratepayer Issues and Considerations.” (2013). National Association of State Utility Consumer Advocates Annual Meeting, Orlando, Florida. November 19.
 60. “Replacement, Reliability & Resiliency: Infrastructure & Ratemaking Issues in the Power & Natural Gas Distribution Industries.” (2013). Louisiana State Bar, Public Utility Section Meetings. November 15.
 61. “Natural Gas Markets: Leveraging the Production Revolution into an Industrial Renaissance.” (2013). International Technical Conference, Houston, TX. October 11.
 62. “Natural Gas, Coal & Power Generation Issues and Trends.” (2013). Southeast Labor and Management Public Affairs Committee Conference, Chattanooga, Tennessee. September 27.
 63. “Recent Trends in Pipeline Replacement Trackers.” (2013). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. September 19.
 64. Discussion Panelist (2013). Think About Energy Summit, America’s Natural Gas Alliance, Columbus Ohio. September 16-17.
 65. “Future Test Years: Issues to Consider.” (2013). National Regulatory Research Institute, Teleseminar on Future Test Years. August 28.
 66. “Industrial Development Outlook for Louisiana.” (2013). Louisiana Water Synergy Project Meetings, Jones Walker Law Firm, Baton Rouge, Louisiana. July 30.
 67. “Natural Gas & Electric Power Coordination Issues and Challenges.” (2013). Utilities State Government Organization Conference, Pointe Clear, Alabama. July 9.
 68. “Natural Gas Market Issues & Trends.” (2013). Western Conference of Public Service Commissioners, Santa Fe, New Mexico. June 3.
 69. “Louisiana Unconventional Natural Gas and Industrial Redevelopment.” (2013). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Annual Legislative Conference, Baton Rouge, Louisiana. May 8.
 70. “Infrastructure Cost Recovery Mechanism: Overview of Issues.” (2013). Energy Bar

- Association Annual Meeting, Washington, D.C. May 1.
71. "GOM Offshore Oil and Gas." (2013). Energy Executive Roundtable, New Orleans, Louisiana. March 27.
 72. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Risk Management Association Luncheon, March 21.
 73. "Natural Gas Market Update and Emerging Issues." (2013). NASUCA Gas Committee Conference Call/Webinar, March 12.
 74. "Unconventional Resources and Louisiana's Manufacturing Development Renaissance." (2013). Baton Rouge Press Club, De La Ronde Hall, Baton Rouge, LA, January 28.
 75. "New Industrial Operations Leveraged by Unconventional Natural Gas." (2013) American Petroleum Institute-Louisiana Chapter. Lafayette, LA, Petroleum Club, January 14.
 76. "What's Going on with Energy? How Unconventional Oil and Gas Development is Impacting Renewables, Efficiency, Power Markets, and All that Other Stuff." (2012). Atlanta Economics Club Monthly Meeting. Atlanta, GA. December 11.
 77. "Trends, Issues, and Market Changes for Crude Oil and Natural Gas." (2012). East Iberville Community Advisory Panel Meeting. St. Gabriel, LA. September 26.
 78. "Game Changers in Crude and Natural Gas Markets." (2012). Chevron Community Advisory Panel Meeting. Belle Chase, LA, September 17.
 79. "The Outlook for Renewables in a Changing Power and Natural Gas Market." (2012). Louisiana Biofuels and Bioprocessing Summit. Baton Rouge, LA. September 11.
 80. "The Changing Dynamics of Crude and Natural Gas Markets." (2012). Chalmette Refining Community Advisory Panel Meeting. Chalmette, LA, September 11.
 81. "The Really Big Game Changer: Crude Oil Production from Shale Resources and the Tuscaloosa Marine Shale." (2012). Baton Rouge Chamber of Commerce Board Meeting. Baton Rouge, LA, June 27.
 82. "The Impact of Changing Natural Gas Prices on Renewables and Energy Efficiency." (2012). NASUCA Gas Committee Conference Call/Webinar. 12 June 2012.
 83. "Issues in Gas-Renewables Coordination: How Changes in Natural Gas Markets Potentially Impact Renewable Development" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.
 84. "Issues in Natural Gas End-Uses: Are We Really Focusing on the Real Opportunities?" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.
 85. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012). Louisiana Oil and Gas Association Annual Meeting, Lake Charles, LA. February 27, 2012.
 86. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012) Louisiana Oil and Gas Association Annual Meeting. Lake Charles, Louisiana. February 27, 2012.
 87. "Louisiana's Unconventional Plays: Economic Opportunities, Policy Challenges. Louisiana Mid-Continent Oil and Gas Association 2012 Annual Meeting. (2012) New

Orleans, Louisiana. January 26, 2012.

88. "EPA's Recently Proposed Cross State Air Pollution Rule ("CSAPR") and Its Impacts on Louisiana." (2011). Bossier Chamber of Commerce. November 18, 2011.
89. "Facilitating the Growth of America's Natural Gas Advantage." (2011). BASF U.S. Shale Gas Workshop Management Meeting. Florham Park, New Jersey. November 1, 2011.
90. "CSAPR and EPA Regulations Impacting Louisiana Power Generation." (2011). Air and Waste Management Association (Louisiana Section) Fall Conference. Environmental Focus 2011: a Multi-Media Forum. Baton Rouge, LA. October 25, 2011.
91. "Natural Gas Trends and Impact on Industrial Development." (2011). Central Gulf Coast Industrial Alliance Conference. Arthur R. Outlaw Convention Center. Mobile, AL. September 22, 2011.
92. "Energy Market Changes and Policy Challenges." (2011). Southeast Manpower Tripartite Alliance ("SEMTA") Summer Conference. Nashville, TN September 2, 2011.
93. "EPA Regulations, Rates & Costs: Implications for U.S. Ratepayers." (2011). Workshop: "A Smarter Approach to Improving Our Environment." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 5, 2011.
94. Panelist/Moderator. Workshop: "Why Wait? Start Energy Independence Today." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 4, 2011.
95. "Facilitating the Growth of America's Natural Gas Advantage." Texas Chemical Council, Board of Directors Summer Meeting. San Antonio, TX. July 28, 2011.
96. "Creating Ratepayer Benefits by Reconciling Recent Gas Supply Opportunities with Past Policy Initiatives." National Association of State Utility Consumer Advocates ("NASUCA"), Monthly Gas Committee Meeting. July 12, 2011.
97. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.
98. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.
99. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.
100. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Consul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.
101. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.
102. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.
103. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas

- Committee, National Association of State Utility Consumer Advocates (“NASUCA”). February 15, 2011.
104. “Regulatory Issues in Inflation Adjustment Mechanisms and Allowances.” (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates (“NASUCA”), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.
 105. “How Current and Proposed Energy Policy Impacts Consumers and Ratepayers.” (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners (“NARUC”), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.
 106. “Energy Outlook: Trends and Policies.” (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L’Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.
 107. “Deepwater Moratorium and Louisiana Impacts.” (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.
 108. “Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon.” (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.
 109. “Long-Term Energy Sector Impacts from the Oil Spill.” (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.
 110. “Overview and Issues Associated with the Deepwater Horizon Accident.” (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.
 111. “Overview and Issues Associated with the Deepwater Horizon Accident.” (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.
 112. “Deepwater Moratorium: Overview of Impacts for Louisiana.” Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.
 113. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.
 114. “The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth.” Second Annual Local Economic Analysis and Research Network (“LEARN”) Conference. Federal Reserve Bank of Atlanta. March 29, 2010.
 115. “Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana.” Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.
 116. “Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry.” LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA
 117. “Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms.” National Association of State Utility Consumer Advocates (“NASUCA”) Annual Meeting. November 10, 2009.
 118. “Louisiana’s Stakes in the Greenhouse Gas Debate.” Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget

- Crisis: Catastrophe or Change? New Orleans, LA.
119. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.
 120. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.
 121. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.
 122. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.
 123. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA
 124. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.
 125. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.
 126. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.
 127. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economics (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.
 128. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.
 129. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.
 130. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.
 131. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.
 132. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.
 133. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007)

- Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.
134. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.
 135. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.
 136. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.
 137. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency." (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.
 138. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.
 139. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.
 140. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.
 141. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.
 142. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.
 143. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.
 144. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.
 145. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.
 146. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.
 147. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.
 148. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.
 149. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG

- Forums.” Los Angeles, California. June 1, 2006.
150. “Regional Energy Infrastructure, Production and Outlook.” (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.
 151. “The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook.” Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.
 152. “Update on Regional Energy Infrastructure and Production.” (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.
 153. “Hurricane Impacts on Energy Production and Infrastructure.” (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.
 154. “LNG—A Premier.” Presentation Given to the U.S. Department of Energy’s “LNG Forums.” Astoria, Washington. April 28, 2006.
 155. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.
 156. The Impacts of Hurricanes Katrina and Rita on Louisiana’s Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.
 157. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L’Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006
 158. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.
 159. “Putting Our Energy Infrastructure Back Together Again.” Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA
 160. “Hurricanes and the Outlook for Energy Markets.” Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.
 161. “Hurricanes, Energy Supplies and Prices.” Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.
 162. “The Impact of the Recent Hurricane’s on Louisiana’s Energy Industry.” Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.
 163. “The Impact of the Recent Hurricanes on Louisiana’s Infrastructure and National Energy Markets.” Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

164. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.
165. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.
166. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.
167. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.
168. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.
169. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.
170. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.
171. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.
172. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.
173. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.
174. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.
175. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.
176. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.
177. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.
178. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.
179. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.
180. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

181. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.
182. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.
183. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.
184. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.
185. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.
186. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.
187. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.
188. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.
189. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.
190. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.
191. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.
192. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.
193. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.
194. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.
195. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

196. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.
197. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.
198. "Power Plant Siting Issues in Louisiana." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 12, 2002.
199. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.
200. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.
201. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.
202. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.
203. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.
204. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development. Baton Rouge, LA, July 16, 2001.
205. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.
206. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.
207. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.
208. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.
209. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

210. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.
211. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.
212. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.
213. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.
214. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.
215. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.
216. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.
217. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.
218. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.
219. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.
220. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.
221. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.
222. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.
223. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.
224. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.
225. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

226. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.
227. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.
228. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.
229. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.
230. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.
231. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.
232. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.
233. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.
234. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996
235. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.
236. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.
237. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.
238. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.
239. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Docket No. 20170179-GU. (2018). Before the Florida Public Service Commission. *In re: Petition for rate increase and approval of depreciation study by Florida City Gas*. On Behalf of the Citizens of the State of Florida. Issues: policy issues concerning long-term gas capacity procurement.
2. Expert Testimony. Docket No. 18-KCPE-095-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval*

- of the Merger of Westar, Inc. and Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.
3. Expert Testimony. Docket No. GR17070776. (2018). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II"). Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.
 4. Expert Affidavit. Case No. 18-489. (2018). Before the Civil District Court for the Parish of Orleans, State of Louisiana. *Bayou Bridge Pipeline, LLC versus The White Castle Lumber and Shingle Company Limited and Jeanerette Lumber & Shingle CO. L.L.C.* Issues: economic impact of crude oil pipeline development.
 5. Expert Testimony. Docket No. 16-036-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: cost of service, rate design, alternative regulation, formula rate plan.
 6. Expert Testimony. Docket No. 2017-AD-0112. (2017). Before the Mississippi Public Service Commission. *In re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project.* On Behalf of the Mississippi Public Utilities Staff. Issues: financial analysis, rates and cost trends, economic impacts of proposal.
 7. Expert Testimony. Case No. 2017-00179. (2017). Before the Public Service Commission, Commonwealth of Kentucky. *Electronic Application of Kentucky power Company For (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish a Regulatory Asset or Liability Related to the Big Sandy 1 Operation Rider; and (5) An Order Granting All Other Required Approvals and Relief.* Issues: rate design, revenue allocation, economic development.
 8. Expert Testimony. Formal Case No. 1142. (2017). Before the Public Service Commission of the District of Columbia. *In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.* On Behalf of the Office of the People's Counsel. Issues: merger/acquisition policy, financial risk, ring-fencing, and reliability.
 9. Expert Testimony. D.P.U. 17-05. (2017). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00.* On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: performance-based ratemaking, multi-factor productivity estimation.
 10. Deposition and Testimony. (2017) Before the Nebraska Section 70, Article 13 Arbitration Panel. *Northeast Nebraska Public Power District, City of South Sioux City Nebraska; City of Wayne, Nebraska; City of Valentine, Nebraska; City of Beatrice, Nebraska; City of Scribner, Nebraska; Village of Walthill, Nebraska, vs. Nebraska Public Power District.* On the Behalf of Baird Holm LLP for the Plaintiffs. Issues: rate discounts; cost of service; utility regulation, economic harm.

11. Expert Testimony. Docket No. 16-052-U. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Application of the Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges and Tariffs*. On the Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.
12. Expert Testimony. Docket No. 16-KCPE-593-ACQ. (2016). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar, Inc. by Great Plains Energy Incorporated*. On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.
13. Expert Testimony. Formal Case No. 1139. (2016). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. On the Behalf of the Office of the People's Counsel for the District of Columbia. Issues: cost of service, rate design, alternative regulation.
14. Expert Affidavit. Docket No. CP15-558-000 (2016). Before the United States of America Federal Energy Regulatory Commission. *PennEast Pipeline Company, LLC*. Affidavit and Reply Affidavit. On the Behalf of the New Jersey Division of Rate Counsel. Issues: pipeline capacity, peak day requirements.
15. Expert Testimony. Docket No. RPU-2016-0002. (2016). Before the Iowa Utilities Board. *In re: Iowa American Water Company application for revision of rates*. On behalf of the Citizens of the State of Florida. Issue: revenue stabilization mechanism, revenue decoupling.
16. Expert Testimony. Docket No. 15-015-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: formula rate plan evaluation.
17. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated)*. On behalf of the Office of Consumer Advocate, Iowa Department of Justice. Issue: load forecasting.
18. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated)*. On behalf of the Citizens of the State of Florida. Issue: off-system sales incentives.
19. Expert Testimony. Project No. 5-103. (2016). United States of America Federal Energy Regulatory Commission. *Confederated Salish and Kootenai Tribes Energy Keepers, Incorporated*. On behalf of the Flathead, Mission, and Jocko Valley Irrigation Districts and the Flathead Joint Board of Control of the Flathead, Mission, and Jocko Valley Irrigation Districts.
20. Expert Testimony. Docket No. 15-098-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas for a General Change or Modification in its Rates,*

- Charges and Tariffs.* On behalf of the Office of the Arkansas Attorney General. Issues: formula rate plan, cost of service and rate design.
21. Expert Testimony. BPU Docket No. GM15101196. (2016). *In the Matter of the Merger of Southern Company and AGL Resources, Inc.* On behalf of the New Jersey Division of Rate Counsel. Issues: merger standards of review, customer dividend contributions, synergy savings and costs to achieve, ratemaking treatment of merger-related costs.
 22. Expert Testimony. Docket No. 15-078-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Joint Application of SourceGas Inc., SourceGas LLC, SourceGas Holdings LLC and Black Hills Utility Holdings, Inc. for all Necessary Authorizations and Approvals for Black Hills Utility Holdings, Inc. to Acquire SourceGas Holdings LLC.* On behalf of the Office of the Arkansas Attorney General. Issues: public policy and regulatory policy associated with the acquisition.
 23. Expert Testimony. Docket No. 15-031-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of SourceGas Arkansas Inc. for an Order Approving the Acquisition of Certain Storage Facilities and the Recovery of Investments and Expenses Associated Therewith.* On behalf of the Office of the Arkansas Attorney General. Issues: cost-benefit analysis, transmission cost analysis, and a due diligence analysis.
 24. Expert Testimony. Docket No. 15-015-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.* On behalf of the Office of the Arkansas Attorney General. Issues: economic development riders and production plant cost allocation.
 25. Expert Testimony. Docket No. 7970. (2015). Before the Vermont Public Service Board. *Petition of Vermont Gas Systems, Inc., for a certificate of public good pursuant to 30 V.S.A. § 248, authorizing the construction of the "Addison Natural Gas Project" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 miles of new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont.* On behalf of AARP-Vermont. Issues: net economic benefits of proposed natural gas transmission project.
 26. Expert Testimony. File No. ER-2014-0370 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of Kansas City Power & Light Company for Authority Implement A General Rate Increase for Electric Service.* On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, class cost of service, and policy and ratemaking considerations in connection with electric vehicle charging stations.
 27. Expert Testimony. File No. ER-2014-0351 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of The Empire District Electric Company for Authority To File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area.* On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, and class cost of service.
 28. Expert Testimony. D.P.U. 14-130 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by*

- the Department of Public Utilities of the Company's 2015 Gas System Enhancement Program Plan, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.*
29. Expert Testimony. D.P.U. 14-131 (2015). Before the Massachusetts Department of Public Utilities. *Petition of The Berkshire Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.*
 30. Expert Testimony. D.P.U. 14-132 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for approval by the Department of Public Utilities of the Companies' Gas System Enhancement Program for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.*
 31. Expert Testimony. D.P.U. 14-133 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Liberty Utilities for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.*
 32. Expert Testimony. D.P.U. 14-134 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.*
 33. Expert Testimony. D.P.U. 14-135 (2015). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.*
 34. Expert Report. Docket No. X-33192 (2015). Before the Louisiana Public Service Commission. *Examination of the Comprehensive Costs and Benefits of Net Metering in Louisiana. On behalf of the Louisiana Public Service Commission. Issues: cost-benefit, cost of service, rate impact.*
 35. Expert Testimony. F.C. 1119 (2014). Before the District of Columbia Public Service Commission. *In the Matter of the Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and new Special Purpose Entity, LLC. On behalf of the Office of the People's Counsel. Issues: economic impact analysis, reliability, consumer investment fund, regulatory oversight, impacts to competitive electricity markets.*
 36. Expert Report. Civil Action 1:08-cv-0046 (2014). Before the U.S. District Court for the Southern District of Ohio. *Anthony Williams, et al., v. Duke Energy International, Inc., et al. On behalf of Markovits, Stock & DeMarco, Attorneys & Counselors at Law. Issues:*

public utility regulation, electric power markets, economic harm.

37. Expert Testimony. D.P.U. 14-64 (2014). Before the Massachusetts Department of Public Utilities. *NSTAR Gas Company/HOPCO Gas Services Agreement. On behalf of the Office of the Public Advocate*. Issues: certain ratemaking features associated with the proposed Gas Service Agreement.
38. Expert Testimony. Docket Nos. 14-0224 and 14-0225 (2014). Before the Illinois Commerce Commission. *In the Matter of the Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service (consolidated)*. On behalf of the People of the State of Illinois. Issues: test year expenses, cost benchmarking analysis, pipeline replacement, and leak rate comparisons.
39. Expert Testimony. Docket 8191 (2014). Before the Vermont Public Service Board. *In Re: Petition of Green Mountain Power Corporation for Approval of a Successor Alternative Regulation Plan*. On the behalf of AARP-Vermont. Issues: Alternative Regulation.
40. Expert Testimony. Docket No. 2013-00168 (2014). Before the Maine Public Utilities Commission. *In the Matter of the Request for Approval of an Alternative Rate Plan (ARP 2014) Pertaining to Central Maine Power Company*. On behalf of the Office of the Public Advocate. Issues: class cost of service study, marginal cost of service study, revenue distribution and rate design.
41. Expert Testimony. D.P.U. 13-90 (2013). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil to the Department of Public Utilities for approval of the rates and charges and increase in base distribution rates for electric service*. On behalf of the Office of the Ratepayer Advocate. Issues: capital cost adjustment mechanism and performance-based regulation.
42. Expert Testimony. BPU Docket Nos. EO13020155 and GO13020156. (2013). Before the State of New Jersey Board of Public Utilities. *I/M/O The Petition of Public Service Electric & Gas Company for the Approval of the Energy Strong Program*. On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.
43. Expert Testimony. D.P.U. 13-75 (2013). Before the Massachusetts Department of Public Utilities. *Investigation by the Department of Public Utilities on its Own Motion as to the Propriety of the Rates and Charges by Bay State Gas Company d/b/a Columbia Gas of Massachusetts set forth in Tariffs M.D.P.U. Nos. 140 through 173, and Approval of an Increase in Base Distribution Rates for Gas Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on April 16, 2013, to be effective May 1, 2013*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement, and leak rate comparisons; environmental benefits analysis; O&M offset; and cost benchmarking analysis.
44. Expert Testimony. Docket No. 13-115 (2013). Before the Delaware Public Service Commission. *In the Matter of the Application of Delmarva Power & Light Company FOR an Increase in Electric Base Rates and Miscellaneous Tariff Changes* (Filed March 22, 2013). On the Behalf of Division of the Public Advocate. Issues: pro forma infrastructure proposal, class cost of service study, revenue distribution, and rate design.

45. Expert Testimony. Formal Case No. 1103 (2013). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. On the Behalf of the Office of the People's Counsel of the District of Columbia. Issues: Pro forma adjustment for reliability investments.
46. Expert Testimony. Case No. 9326 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Electric Reliability Investment ("ERI") initiatives, pro forma gas infrastructure proposal, tracker mechanisms, class cost of service study, revenue distribution, and rate design
47. Rulemaking Testimony. (2013). Before the Louisiana Tax Commission. Examination of Louisiana Assessors' Association Well Diameter Analysis, economic development policies regarding midstream assets and industrial development.
48. Expert Testimony. Case No. 9317 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.
49. Expert Testimony. Case No. 9311 (2013). Before the Public Service Commission of Maryland. *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, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.
50. Expert Testimony. Docket No. 12AL-1268G (2013). Before the Public Utilities Commission of the State of Colorado. *In the Matter of the Tariff Sheets Filed by Public Service Company of Colorado with Advice No. 830 – Gas. Answer*. On the Behalf of the Colorado Office of Consumer Counsel. Issues: Pipeline System Integrity Adjustment, tracker mechanisms, pipeline replacement and leak rate comparisons.
51. Expert Testimony. BPU Docket No. EO12080721 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric & Gas Company for Approval of an Extension of Solar Generation Program*. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal, Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design and net economic benefits.
52. Expert Testimony. BPU Docket No. EO12080726 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Loan III Program*. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal and Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design.
53. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate

- Counsel. December 17, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.
54. Expert Testimony. D.P.U. 12-25. (2012). Before the Massachusetts Department of Public Utilities. *In the Matter of Bay State Gas Company d/b/a/ Columbia Gas Company of Massachusetts Request for Increase in Rates*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement and leak rate comparisons.
 55. Expert Testimony. Docket Nos. UE-120436, et.al. (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms, attrition adjustments.
 56. Expert Testimony. Case No. 9286. (2012) Before the Public Service Commission of Maryland. *In Re: Potomac Electric Power Company ("Pepco") General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.
 57. Expert Testimony. Case No 9285. (2012) Before the Public Service Commission of Maryland. *In Re: the Delmarva Power and Light Company General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.
 58. Expert Testimony. Docket Nos. UE-110876 and UG-110877 (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms.
 59. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. February 3, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.
 60. Expert Testimony. Docket No. NG 0067. (2012). Before the Public Service Commission of Nebraska. *In the Matter of the Application of SourceGas Distribution, LLC Approval of a General Rate Increase*. On the Behalf of the Public Advocate. January 31, 2012. Issues: Revenue Decoupling, Customer Adjustments, Weather Normalization Adjustments, Class Cost of Service Study, Rate Design.
 61. Expert Testimony. Docket No. G-04204A-11-0158. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

62. Expert Testimony. Formal Case Number 1087. (2011). Before the Public Service Commission of the District of Columbia. On the Behalf of the Office of the People's Counsel of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. Issues: Regulatory lag, ratemaking principles, reliability-related capital expenditure tracker proposals.
63. Expert Affidavit. Case No. 11-1364. (2011). *The State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission v. United States Environmental Protection Agency and Lisa P. Jackson*. Before the United States Court of Appeals for the District of Columbia Circuit. On the behalf of the State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.
64. Expert Affidavit. Docket No. EPA-HQ-OAR-2009-0491. (2011). Before the U.S. Environmental Protection Agency. *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*. On the Behalf of the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.
65. Expert Testimony. Case No. 9296. (2011). Before the Maryland Public Service Commission. *On the Behalf of the Maryland Office of People's Counsel. In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and Revise its Terms and Conditions for Gas Service*. Issues: Infrastructure Cost Recovery Rider; Class Cost of Service Modeling; Revenue Distribution; Rate Design.
66. Expert Testimony. Docket No. G-01551A-10-0458. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.
67. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. *In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company*. Issues: Revenue Decoupling and Rate Design. (Direct and Rebuttal)
68. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Capital Cost Rider, Revenue Decoupling.
69. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue*

Decoupling Mechanism. Issues: Pipeline Replacement Rider, Revenue Decoupling.

70. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.
71. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.
72. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.
73. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.
74. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.
75. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.
76. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.
77. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.
78. Congressional Testimony. Before the United States Congress. (2010). U.S. House of

Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

79. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.
80. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.
81. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.
82. Expert Testimony. Docket No. 09505-El. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.
83. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.
84. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.
85. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.
86. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

87. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.
88. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.
89. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.
90. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.
91. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)
92. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)
93. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.
94. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.
95. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August

20, 2008.

96. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).
97. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.
98. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.
99. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.
100. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.
101. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.
102. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.
103. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)
104. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.
105. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public

- Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.
106. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.
 107. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).
 108. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.
 109. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.
 110. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.
 111. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)
 112. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.
 113. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.
 114. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation

- Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).
115. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.
 116. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.
 117. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005
 118. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.
 119. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.
 120. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.
 121. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al.* (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.
 122. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776; 480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778; 489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912; 503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.
 123. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.
 124. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)
 125. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and

- the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.
126. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.
 127. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.
 128. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.
 129. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.
 130. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.
 131. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.
 132. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).
 133. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.
 134. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.
 135. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.
 136. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the

Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

137. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.
138. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.
139. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.
140. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.
141. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.
142. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.
143. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.
144. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.
145. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Contributor, 2014-Current, *Wall Street Journal*, *Journal Reports*, *Energy*

Editorial Board Member, 2015-2017, *Utilities Policy*

Referee, 2014-Current, *Utilities Policy*

Referee, 2010-Current, *Economics of Energy & Environmental Policy*

Referee, 1995-Current, *Energy Journal*

Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*

Referee, 2005, *Energy Policy*

Referee, 2004, *Southern Economic Journal*

Referee, 2002, *Resource & Energy Economics*

Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists ("IAEE"), United States Association of Energy Economics ("USAEE"), the National Association for Business Economics ("NABE"), and the Energy Bar Association (National and Louisiana Chapter; current Board member of LA chapter).

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current).

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Energy and the Environment (Survey Course)

Principles of Microeconomic Theory

Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and

Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept. of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on "Society and the Coast."

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

"Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation." Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

"Regulatory and Ratemaking Issues with Cost and Revenue Trackers." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

"Regulatory and Ratemaking Issues Associated with Cost and Expense Adjustment Mechanisms." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 28, 2011.

"Utility Incentives, Decoupling, and Renewable Energy Programs." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 29, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 6-8, 2012.

"Traditional and Incentive Ratemaking Workshop." New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.

"Traditional and Incentive Ratemaking Workshop." New Jersey Board of Public Utilities Staff. Newark, NJ. March 1, 2013.

“Natural Gas Issues and Recent Market Trends.” Michigan State University Institute of Public Utilities, GridSchool Regulatory Studies Program, East Lansing, Mich., March 29, 2017.

“Gas Supply Planning and Procurement: Regulatory Overview and issues.” Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

“Natural Gas Supply Issues and Challenges.” Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

“Incentives, Risk and Changes in the Nature of Regulation.” Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 18, 2017.

“Traditional and Alternative Forms of Regulation: Background and Overview.” Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

“Traditional and Alternative Forms of Regulation: Utility and policy motivations for risk and change.” Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

“Traditional and Alternative Forms of Regulation: Incentives and Formula Based Methods.” Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

THESIS/DISSERTATIONS COMMITTEES

Active:

1 Thesis Committee Memberships (Environmental Studies)

2 Ph.D. Dissertation Committee (Economics)

Completed:

8 Thesis Committee Memberships (Environmental Studies, Geography)

4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).

2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)

1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Committee Member, Energy Education Curriculum Committee. E.J. Ourso College of Business. LSU (2016-Current).

Chairman, LSU Energy Initiative/LSU Energy Council (2014-Current).

Co-Director & Steering Committee Member, LSU Coastal Marine Institute (2009-2014).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-2014); Full Member (2014-current).

LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Board Member (2018). Energy Bar Association, Louisiana Chapter.

Program Committee Member (2017). Gulf Coast Power Association Conference. New Orleans, LA.

Program Committee Member (2016). Gulf Coast Power Association Conference. New Orleans, LA.

Program Committee Member (2015). Gulf Coast Power Association Workshop/Special Briefing. "Gulf Coast Disaster Readiness: A Past, Present and Future Look at Power and Industry Readiness in MISO South."

Advisor (2008). National Association of Regulatory Utility Commissioners ("NARUC"). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics ("IAEE") Nominating

Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Table of Exhibits

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Customer Density

Witness: Dismukes
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Company	Number of Customers	Substation Capacity (Mva)	Number of Transformers	Substation Capacity (Mva/ 1,000 Customers)	Number of Transformers (Transformers/ 1,000 Customers)	Capacity Rank	Transformer Rank	Residential Customer Charge	Small Commercial Customer Charge
OtterTail Power Company	131,852	5,075	105	38.49	0.80	3	8	\$ 15.23	\$ 24.90
ALLETE, Inc. ³	146,370	8,157	221	55.73	1.51	1	4		
MN								8.00	10.50
Black Hills Energy ^{1,3}	72,026	2,607	95	36.20	1.32	4	5		
SD								9.25	12.00
WY								15.50	28.00
Cheyenne Light Fuel & Power d/b/a Black Hills Energy	42,013	1,633	24	38.87	0.57	2	12		
WY								13.00	16.00
Interstate Power and Light Co ³	489,611	6,364	549	13.00	1.12	13	6		
IA								13.50	24.00
Madison Gas & Electric Co	152,603	1,203	99	7.88	0.65	16	10		
WI								19.00	23.93
MDU Resources	142,901	5,002	528	35.00	3.69	6	1		
MT								5.17	15.21
ND								13.99	25.55
SD								7.51	15.51
WY								25.00	29.99
MidAmerican Energy Co ³	770,335	21,774	517	28.27	0.67	9	9		
IA								8.50	10.00
IL								7.25	18.07
SD								8.00	10.00

¹ Black Hills energy has fewer than 50 Montana customers, so customer charges were excluded.

² Wyoming rates are limited to Yellowstone Park and thus excluded from the analysis.

³ The lowest General Service rate is used due to lack of Small Commercial Service Rates on companies' tariffs.

Customer Density

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-1
Page 2 of 2

Company	Number of Customers	Substation Capacity (Mva)	Number of Transformers	Substation Capacity (Mva/ 1,000 Customers)	Number of Transformers (Transformers/ 1,000 Customers)	Capacity Rank	Transformer Rank	Residential Customer Charge	Small Commercial Customer Charge
Northern States Power (Minnesota)	1,466,398	44,906	630	30.62	0.43	8	15		
MN								8.00	10.00
ND								14.50	16.75
SD								8.25	9.00
Northern States Power (Wisconsin)	257,668	9,180	281	35.63	1.09	5	7		
MI								9.00	11.50
WI								17.00	17.00
NorthWestern Energy LLC ^{2,3}	431,099	14,364	819	33.32	1.90	7	3		
MT								4.10	7.35
SD								6.00	10.00
Northwestern Wisconsin Elec Co³	13,898	304	40	21.87	2.88	12	2		
WI								11.00	16.00
Superior Water and Light Co³	14,782	345	6	23.34	0.41	10	16		
WI								9.00	10.00
Wisconsin Electric Power Co³	1,122,784	25,026	641	22.29	0.57	11	13		
MI								12.00	25.00
WI								16.00	16.00
Wisconsin Power & Light Co³	469,709	5,729	304	12.20	0.65	14	11		
WI								15.00	17.00
Wisconsin Public Service Corp	442,281	4,459	243	10.08	0.55	15	14		
WI								\$ 21.00	\$ 27.63

¹ Black Hills energy has fewer than 50 Montana customers, so customer charges were excluded.

² Wyoming rates are limited to Yellowstone Park and thus excluded from the analysis.

³ The lowest General Service rate is used due to lack of Small Commercial Service Rates on companies' tariffs.

Company's Proposed and Alternative CCROSS RROR

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-2
Page 1 of 1

	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Water Heating	Controlled Service Interruptible	Controlled Service Demand
Company's CCROSS										
Return	2.71%	2.07%	7.67%	8.72%	-3.42%	3.01%	1.88%	-0.90%	-1.16%	5.31%
Relative ROR	0.52	0.40	1.47	1.67	(0.66)	0.58	0.36	(0.17)	(0.22)	1.02
Alternative CCROSS										
Return	4.91%	1.44%	8.11%	7.22%	-5.42%	4.03%	2.75%	-3.42%	-4.67%	1.60%
Relative ROR	0.94	0.28	1.56	1.39	(1.04)	0.77	0.53	(0.66)	(0.90)	0.31

Source: OTP's Class Cost of Service Study; Attachment 1 to DR-PSC-09.6.xlsx; and Results of Alternative CCROSS.

Results of Alternative CCSS

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-3
Page 1 of 1

Account Description	Total North Dakota Distribution	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interrupt	Controlled Service Deferred
Rate Base											
Total Electric Distribution Plant	\$ 758,395,145	\$ 239,241,818	\$ 18,849,481	\$ 184,764,841	\$ 207,391,132	\$ 829,040	\$ 17,065,520	\$ 6,628,209	\$ 9,966,821	\$ 65,093,431	\$ 8,564,852
Less: Depreciation Reserve	\$ (304,752,303)	\$ (96,829,889)	\$ (7,649,350)	\$ (74,177,032)	\$ (83,021,003)	\$ (338,208)	\$ (7,254,581)	\$ (2,699,964)	\$ (4,064,285)	\$ (25,266,858)	\$ (3,451,132)
Total Net Electric Distribution Plant	\$ 453,642,842	\$ 142,411,929	\$ 11,200,130	\$ 110,587,809	\$ 124,370,129	\$ 490,832	\$ 9,810,939	\$ 3,928,245	\$ 5,902,536	\$ 39,826,573	\$ 5,113,720
Plus: Rate Base Additions	\$ 16,593,419	\$ 5,259,318	\$ 392,664	\$ 4,083,450	\$ 4,697,751	\$ 15,229	\$ 357,461	\$ 148,991	\$ 194,256	\$ 1,265,414	\$ 178,884
Less: Rate Base Deductions	\$ (116,044,466)	\$ (36,429,796)	\$ (2,865,058)	\$ (28,289,002)	\$ (31,814,599)	\$ (125,558)	\$ (2,509,695)	\$ (1,004,868)	\$ (1,509,903)	\$ (10,187,868)	\$ (1,308,119)
Total Rate Base	\$ 354,191,795	\$ 111,241,451	\$ 8,727,736	\$ 86,382,257	\$ 97,253,281	\$ 380,503	\$ 7,658,705	\$ 3,072,368	\$ 4,586,888	\$ 30,904,119	\$ 3,984,485
Operating Income											
Electric Operating Revenues											
Retail Sales	148,071,951	48,209,916	2,612,688	38,950,615	43,160,710	59,083	2,869,144	1,203,986	1,085,033	8,397,154	1,523,622
Other Operating Revenues	10,047,294	3,344,556	244,318	2,425,952	2,643,490	10,663	208,870	87,271	125,577	847,695	108,900
Total Electric Operating Revenues	158,119,244	51,554,472	2,857,006	41,376,567	45,804,200	69,746	3,078,014	1,291,258	1,210,610	9,244,848	1,632,523
Electric Operating Expenses											
Operating and Maintenance Expenses	108,238,348	36,179,687	2,137,109	25,459,059	29,189,649	78,658	2,139,562	966,823	1,171,046	9,626,049	1,290,707
Depreciation & Amortization Expense	21,425,301	6,934,831	513,860	5,211,827	5,864,742	21,318	460,292	191,612	265,839	1,722,923	238,058
General Taxes	4,905,891	1,540,105	121,123	1,195,945	1,344,993	5,308	106,100	42,482	63,833	430,702	55,302
Investment Tax Credit	(526,207)	(165,996)	(13,079)	(128,198)	(143,897)	(575)	(11,841)	(4,599)	(6,915)	(45,165)	(5,943)
Total Income Taxes	5,095,310	1,433,177	(40,442)	2,504,202	2,383,568	(14,907)	63,778	5,991	(133,384)	(1,091,485)	(15,188)
Deferred Income Taxes	1,317,383	413,566	32,525	321,148	361,172	1,425	28,491	11,408	17,141	115,657	14,850
Total Electric Operating Expenses	140,456,028	46,335,369	2,751,097	34,563,984	39,000,227	91,227	2,786,382	1,213,716	1,377,560	10,758,681	1,577,786
Total Operating Income	18,454,393	5,466,673	125,356	7,005,534	7,021,249	(20,631)	308,283	84,350	(156,724)	(1,443,341)	63,645
Rate of Return on Rate Base ("ROR")	5.21%	4.91%	1.44%	8.11%	7.22%	-5.42%	4.03%	2.75%	-3.42%	-4.67%	1.60%
Relative Rate of Return ("RROR")	1.00	0.94	0.28	1.56	1.39	(1.04)	0.77	0.53	(0.66)	(0.90)	0.31

Source: Company's Workpaper "53 Vol 3_E.03 2018 ND Budget TEST Year CCSS"; Company's Response to DR ND-PSC-13.04; Company Minimum System Study.

Results of Company's CCROSS

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-4
Page 1 of 1

Account Description	Total North Dakota Distribution	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interrupt	Controlled Service Deferred
Rate Base											
Total Electric Distribution Plant	\$ 758,395,145	\$ 268,789,509	\$ 18,306,082	\$ 188,625,881	\$ 193,923,428	\$ 697,718	\$ 18,079,773	\$ 6,995,635	\$ 8,323,741	\$ 47,634,736	\$ 7,018,641
Less: Depreciation Reserve	(304,752,303)	(107,455,040)	(7,425,306)	(75,381,606)	(78,158,675)	(293,907)	(7,542,558)	(2,820,798)	(3,496,405)	(19,270,108)	(2,907,900)
Total Net Electric Distribution Plant	\$ 453,642,842	\$ 161,334,469	\$ 10,880,777	\$ 113,244,275	\$ 115,764,752	\$ 403,812	\$ 10,537,216	\$ 4,174,837	\$ 4,827,336	\$ 28,364,629	\$ 4,110,741
Plus: Rate Base Additions	\$ 16,593,419	\$ 5,810,634	\$ 381,790	\$ 4,152,341	\$ 4,449,024	\$ 12,752	\$ 375,583	\$ 155,664	\$ 163,271	\$ 942,238	\$ 150,121
Less: Rate Base Deductions	(116,044,466)	(41,270,291)	(2,783,366)	(28,968,541)	(29,613,294)	(103,297)	(2,695,481)	(1,067,947)	(1,234,861)	(7,255,836)	(1,051,551)
Total Rate Base	\$ 354,191,795	\$ 125,874,811	\$ 8,479,201	\$ 88,428,075	\$ 90,600,482	\$ 313,267	\$ 8,217,318	\$ 3,262,553	\$ 3,755,746	\$ 22,051,030	\$ 3,209,311
Operating Income											
Electric Operating Revenues											
Retail Sales	\$ 148,071,951	\$ 48,209,916	\$ 2,612,688	\$ 38,950,615	\$ 43,160,710	\$ 59,083	\$ 2,869,144	\$ 1,203,986	\$ 1,085,033	\$ 8,397,154	\$ 1,523,622
Other Operating Revenues	10,047,294	3,746,203	237,540	2,482,338	2,460,833	8,816	224,286	92,505	102,755	604,405	87,611
Total Electric Operating Revenues	\$ 158,119,244	\$ 51,956,119	\$ 2,850,227	\$ 41,432,953	\$ 45,621,544	\$ 67,899	\$ 3,093,430	\$ 1,296,492	\$ 1,187,788	\$ 9,001,558	\$ 1,611,233
Electric Operating Expenses											
Operating and Maintenance Expenses	\$ 108,238,348	\$ 38,996,151	\$ 2,069,090	\$ 25,770,073	\$ 27,986,807	\$ 64,748	\$ 2,227,844	\$ 998,656	\$ 999,882	\$ 7,981,773	\$ 1,143,324
Depreciation & Amortization Expense	21,425,301	7,575,335	500,518	5,285,496	5,571,743	18,631	478,092	198,961	231,474	1,359,814	205,237
General Taxes	4,905,891	1,744,741	117,669	1,224,673	1,251,930	4,367	113,954	45,149	52,205	306,747	44,455
Investment Tax Credit	(526,207)	(186,498)	(12,702)	(130,877)	(134,552)	(484)	(12,545)	(4,854)	(5,775)	(33,051)	(4,870)
Total Income Taxes	5,095,310	227,473	(12,339)	2,368,914	2,906,339	(9,132)	26,520	(7,740)	(61,854)	(390,558)	47,686
Deferred Income Taxes	1,317,383	468,517	31,598	328,863	336,182	1,173	30,600	12,124	14,019	82,371	11,938
Total Electric Operating Expenses	\$ 140,456,028	\$ 48,825,720	\$ 2,693,835	\$ 34,847,143	\$ 37,918,449	\$ 79,303	\$ 2,864,466	\$ 1,242,296	\$ 1,229,950	\$ 9,307,096	\$ 1,447,771
Total Operating Income	\$ 18,454,393	\$ 3,412,418	\$ 175,289	\$ 6,783,796	\$ 7,904,724	\$ (10,715)	\$ 247,020	\$ 61,466	\$ (33,919)	\$ (256,217)	\$ 170,530
Rate of Return on Rate Base ("ROR")	5.21%	2.71%	2.07%	7.67%	8.72%	-3.42%	3.01%	1.88%	-0.90%	-1.16%	5.31%
Relative Rate of Return ("RROR")	1.00	0.52	0.40	1.47	1.67	-0.66	0.58	0.36	-0.17	-0.22	1.02

Source: Company's Workpaper "53 Vol3_E.03 2018 ND Budget TEST Year CCROSS."

Company's Current and Proposed RROR

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-5
Page 1 of 1

	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Water Heating	Controlled Service Interruptible	Controlled Service Demand
Current										
Return	2.71%	2.07%	7.67%	8.72%	-3.42%	3.01%	1.88%	-0.90%	-1.16%	5.31%
Relative ROR	0.52	0.40	1.47	1.67	(0.66)	0.58	0.36	(0.17)	(0.22)	1.02
Proposed										
Return	5.97%	4.69%	9.94%	11.17%	-1.19%	5.83%	4.87%	1.56%	2.08%	7.75%
Relative ROR	0.75	0.59	1.25	1.40	(0.15)	0.73	0.61	0.20	0.26	0.97

Source: OTP's Class Cost of Service Study; Attachment 1 to DR-ND-PSC-09.6.xlsx.

Company's Prior Case RROR

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-6
Page 1 of 1

	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Water Heating	Controlled Service Interruptible	Controlled Service Demand
Case No. PU-08-862 (as Filed)										
Return	3.51%	2.51%	12.23%	12.09%	-3.21%	-0.59%	-0.01%	-2.27%	-9.54%	1.34%
Relative ROR	0.51	0.36	1.77	1.75	-0.46	-0.09	0.00	-0.33	-1.38	0.19
Case No. PU-08-862 (Approved)										
Return	4.85%	3.50%	12.90%	12.09%	-2.02%	3.50%	3.33%	-0.84%	-3.84%	3.75%
Relative ROR	0.60	0.43	1.60	1.50	(0.25)	0.43	0.41	(0.10)	(0.48)	0.46
Case No. PU-17-398										
Return	2.71%	2.07%	7.67%	8.72%	-3.42%	3.01%	1.88%	-0.90%	-1.16%	5.31%
Relative ROR	0.52	0.40	1.47	1.67	(0.66)	0.58	0.36	(0.17)	(0.22)	1.02

Source: Case No. PU-08-862, OTP's Class Cost of Service Study, Direct Testimony of Peter Beithon, Schedule 10, p.1; and Case No. PU-08-862, Order on Settlement, November 25, 2009, p. 9.

Alternative Revenue Distribution and Rate Design

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-7
Page 1 of 2

	Total North Dakota Distribution	Residential	Farms	General Service	Large General Service
<u>Cost of Service Study Results</u>					
Operating Income	\$ 18,454,393	\$ 5,466,673	\$ 125,356	\$ 7,005,534	\$ 7,021,249
Rate Base	\$ 354,191,795	\$ 111,241,451	\$ 8,727,736	\$ 86,382,257	\$ 97,253,281
ROR	5.21%	4.91%	1.44%	8.11%	7.22%
Unitized ROR	1.00	0.94	0.28	1.56	1.39
<u>Rate Schedule Specific Revenue Increase Allocation</u>					
Revenue Requirement	\$ 15,715,320				
Operating Income Deficiency	\$ 9,774,693				
ROR	7.97%				
<u>Proposed Revenue Allocation</u>					
Operating Income at Fully Equalized (7.97%)	\$ 28,229,086	\$ 8,865,944	\$ 695,601	\$ 6,884,666	\$ 7,751,087
Operating Income Increase at RROR	\$ 9,774,693	\$ 3,399,271	\$ 570,245	\$ (120,868)	\$ 729,838
Revenue Conversion Factor	1.6078	1.6078	1.6078	1.6078	1.6078
Incremental Revenue Requirement at Proposed ROR	15,715,320	5,465,198	916,814	(194,326)	1,173,401
Percent Increase at Proposed ROR	10.62%	11.34%	35.09%	-0.50%	2.72%
Relative Revenue Increase	1.00	1.07	3.30	(0.05)	0.26
<u>Step One Increase</u>					
Maximum Increase at 1.25 times System Average Increase	13.27%	0.00%	13.27%	0.00%	0.00%
Step One Revenue Increase	2,345,960	-	346,795	-	-
Remaining Revenue Deficiency	13,369,360				
<u>Step Two Increase</u>					
Basis to Allocate Step Two Increase	130,321,241	48,209,916	-	38,950,615	43,160,710
Allocation of Shortfall to Remaining Customer Classes	13,369,360	4,945,746	-	3,995,855	4,427,759
Total Required Increase	15,715,320	4,945,746	346,795	3,995,855	4,427,759
<u>Rate Schedule Specific Revenue Increase Allocation</u>					
Annualized Current Base Rate Revenue ¹	\$ 147,995,250	\$ 48,209,916	\$ 2,612,687	\$ 38,950,615	\$ 43,160,710
Revenue Change (\$)	\$ 15,715,320	\$ 4,945,746	\$ 346,795	\$ 3,995,855	\$ 4,427,759
Proposed Revenue	\$ 163,710,570	\$ 53,155,662	\$ 2,959,482	\$ 42,946,470	\$ 47,588,469
Revenue Change based on Annualized Current Revenue (%)	10.62%	10.26%	13.27%	10.26%	10.26%
Rate Change as a Percentage of Overall Base Rate Revenue Change		0.97	1.25	0.97	0.97

Source: Alternative CCROSS; and Company's workpaper "43Vol 2b Schedule 3 (E Schedules) NOT PUBLIC," Schedule E-2.

Alternative Revenue Distribution and Rate Design

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-7
Page 2 of 2

	Irrigation		Outdoor Lighting		OPA		Controlled Water Heating		Controlled Service Interruptible		Controlled Service Deferred	
<u>Cost of Service Study Results</u>												
Operating Income	\$	(20,631)	\$	308,283	\$	84,350	\$	(156,724)	\$	(1,443,341)	\$	63,645
Rate Base	\$	380,503	\$	7,658,705	\$	3,072,368	\$	4,586,888	\$	30,904,119	\$	3,984,485
ROR		-5.42%		4.03%		2.75%		-3.42%		-4.67%		1.60%
Unitized ROR		-1.04		0.77		0.53		-0.66		-0.90		0.31
<u>Proposed Revenue Allocation</u>												
Operating Income at Fully Equalized (7.97%)	\$	30,326	\$	610,399	\$	244,868	\$	365,575	\$	2,463,058	\$	317,563
Operating Income Increase at RROR	\$	50,957	\$	302,116	\$	160,517	\$	522,299	\$	3,906,399	\$	253,919
Revenue Conversion Factor		1.6078		1.6078		1.6078		1.6078		1.6078		1.6078
Incremental Revenue Requirement at Proposed ROR		81,927		485,729		258,073		839,729		6,280,536		408,240
Percent Increase at Proposed ROR		138.67%		16.93%		21.43%		77.39%		75.00%		27.77%
Relative Revenue Increase		13.06		1.59		2.02		7.29		7.06		2.62
<u>Step One Increase</u>												
Maximum Increase at 1.25 times System Average Increase		13.27%		13.27%		13.27%		13.27%		13.27%		13.27%
Step One Revenue Increase		7,842		380,836		159,811		144,022		1,111,548		195,106
Remaining Revenue Deficiency												
<u>Step Two Increase</u>												
Basis to Allocate Step Two Increase		-		-		-		-		-		-
Allocation of Shortfall to Remaining Customer Classes		-		-		-		-		-		-
Total Required Increase		7,842		380,836		159,811		144,022		1,111,548		195,106
<u>Rate Schedule Specific Revenue Increase Allocation</u>												
Annualized Current Base Rate Revenue ¹	\$	59,081	\$	2,869,142	\$	1,203,986	\$	1,085,033	\$	8,374,186	\$	1,469,894
Revenue Change (\$)	\$	7,842	\$	380,836	\$	159,811	\$	144,022	\$	1,111,548	\$	195,106
Proposed Revenue	\$	66,923	\$	3,249,978	\$	1,363,797	\$	1,229,055	\$	9,485,734	\$	1,665,000
Revenue Change based on Annualized Current Revenue (%)		13.27%		13.27%		13.27%		13.27%		13.27%		13.27%
Rate Change as a Percentage of Overall Base Rate Revenue Change		1.25		1.25		1.25		1.25		1.25		1.25

Source: Alternative CCROSS; and Company's workpaper "43Vol 2b Schedule 3 (E Schedules) NOT PUBLIC," Schedule E-2.

Company's Current and Proposed Rates and Recommended Rates

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-8
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Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule Residential							
Residential Monthly Customer Charge	\$ 8.00	\$ 8.52	\$15.23	\$15.23	78.8%	\$ 8.85	3.9%
Seasonal Fixed Charge							
Summer	\$ 32.00	\$ 34.08	\$60.92	\$60.92	78.8%	\$ 35.40	3.9%
Winter	\$ 32.00	\$ 34.08	\$60.92	\$60.92	78.8%	\$ 35.40	3.9%
Kilowatt-hour charge							
Energy Tier 1							
Summer	\$ 0.08444	\$ 0.09704	\$ 0.08155	\$ 0.10831	11.6%	\$ 0.10833	11.6%
Winter	\$ 0.07863	\$ 0.09085	\$ 0.06255	\$ 0.08931	-1.7%	\$ 0.10088	11.0%
Energy Tier 2							
Summer	\$ 0.08444	\$ 0.09704	N/A		N/A	\$ 0.10833	11.6%
Winter	\$ 0.07173	\$ 0.08351	N/A		N/A	\$ 0.09202	10.2%
Schedule Residential Demand Control							
Residential Monthly Customer Charge	\$ 18.38	\$ 19.57	\$ 20.10	\$20.10	2.7%	\$ 20.10	2.7%
Kilowatt-hour charge							
Summer	\$ 0.04627	\$ 0.05639	\$ 0.04912	\$ 0.07588	34.6%	\$ 0.06308	11.9%
Winter	\$ 0.04671	\$ 0.05686	\$ 0.03812	\$ 0.06488	14.1%	\$ 0.06368	12.0%
Demand per kW							
Summer	\$ 6.52	\$ 6.94	\$ 8.00	\$8.00	15.2%	\$ 7.31	5.3%
Winter	\$ 2.63	\$ 2.80	\$ 8.00	\$8.00	185.6%	\$ 2.95	5.3%

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.

Source: Direct Testimony of David G. Prazak, Table 6 – Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Company's Current and Proposed Rates and Recommended Rates

Witness: Dismukes
Case No. PU-17-398
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Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule Farm Service							
Monthly Customer Charge	\$ 12.00	\$ 12.78	\$ 17.40	\$ 17.40	36.2%	\$ 13.27	3.8%
Facilities Charge							
Single Phase Facilities Charge	\$ -		\$ 10.00	\$ 10.00		\$ -	
All Three Phase Facilities			\$ 20.00	\$ 20.00			
Overhead =< 25kVa	\$ 3.37	\$ 3.59	N/A			\$ 3.37	-6.1%
Overhead > 25kVa	\$ 3.93	\$ 4.19	N/A			\$ 3.93	
Underground <= 25kVa	\$ 9.39	\$ 10.00	N/A			\$ 9.39	
Underground > 25kVa	\$ 10.78	\$ 11.48	N/A			\$ 10.78	
Kilowatt-hour charge							
First 1600 kWh							
Summer	\$ 0.07642	\$ 0.09171	\$ 0.07000	\$ 0.09799	6.8%	\$ 0.10691	16.6%
Winter	\$ 0.06971	\$ 0.08457	\$ 0.05100	\$ 0.07899	-6.6%	\$ 0.09753	15.3%
Excess kWh							
Summer	\$ 0.06495	\$ 0.07950	N/A			\$ 0.09087	14.3%
Winter	\$ 0.05925	\$ 0.07343	N/A			\$ 0.08289	12.9%
Schedule Small General Service - Under 20 kW							
Metered Service Secondary							
Monthly Customer Charge	\$ 13.00	\$ 13.84	\$ 24.90	\$ 24.90	79.9%	\$ 14.38	3.9%
Kilowatt-hour charge							
Summer	\$ 0.08509	\$ 0.09756	\$ 0.07371	\$ 0.10041	2.9%	\$ 0.10938	12.1%
Winter	\$ 0.07762	\$ 0.08960	\$ 0.05471	\$ 0.08141	-9.1%	\$ 0.09977	11.3%
Schedule Small General Service - Under 20 kW							
Metered Service Primary							
Monthly Customer Charge	\$ 13.00	\$ 13.84	\$ 24.90	\$ 24.90	79.9%	\$ 14.38	3.9%
Kilowatt-hour charge							
Summer	\$ 0.08471	\$ 0.09715	\$ 0.07103	\$ 0.09773	0.6%	\$ 0.10959	12.8%
Winter	\$ 0.07725	\$ 0.08921	\$ 0.05203	\$ 0.07873	-11.7%	\$ 0.09994	12.0%

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.

Source: Direct Testimony of David G. Prazak, Table 6 – Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Company's Current and Proposed Rates and Recommended Rates

Witness: Dismukes
Case No. PU-17-398
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Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule General Service - 20 kW or Greater							
Secondary Service							
Monthly Customer Charge	\$ 12.00	\$ 12.78	\$ 31.90	\$ 31.90	149.6%	\$ 13.27	3.8%
Facilities Charge	\$ 0.52	\$ 0.55	\$ 0.98	\$ 0.98	77.0%	\$ 0.52	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.08213	\$ 0.09440	\$ 0.07268	\$ 0.09938	5.3%	\$ 0.10540	11.6%
Winter	\$ 0.07492	\$ 0.08673	\$ 0.06168	\$ 0.08838	1.9%	\$ 0.09615	10.9%
Schedule General Service - 20 kW or Greater							
Primary Service							
Monthly Customer Charge	\$ 12.00	\$ 12.78	\$ 21.30	\$ 21.30	66.7%	\$ 13.27	3.8%
Facilities Charge	\$ 0.38	\$ 0.40	\$ 0.65	\$ 0.65	60.6%	\$ 0.38	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.08176	\$ 0.09401	\$ 0.07005	\$ 0.09675	2.9%	\$ 0.10439	11.0%
Winter	\$ 0.07456	\$ 0.08634	\$ 0.05905	\$ 0.08575	-0.7%	\$ 0.09520	10.3%
Schedule General Service - Time of Use							
(Commercial TOU)							
Monthly Customer Charge	\$ 16.00	\$ 17.04	\$ 219.00	\$ 219.00	1185.3%	\$ 17.70	3.9%
Facilities Charge	\$ 0.52	\$ 0.55	\$ 0.98	\$ 0.98	77.0%	\$ 0.52	-6.1%
Demand per kW							
Declared- Peak	N/A		N/A			N/A	
Intermediate							
Summer	\$ 2.51	\$ 2.67	\$ 3.44	\$ 3.44	28.7%	\$ 2.82	5.5%
Winter	\$ 2.90	\$ 3.09	\$ 5.12	\$ 5.12	65.8%	\$ 3.26	5.6%
Off-Peak	\$ -	\$ -	\$ -	\$ -		\$ -	
Kilowatt-hour charge							
Energy - Declared-Peak							
Summer	\$ 0.20663	\$ 0.22699	\$ 0.48071	\$ 0.50741	123.5%	\$ 0.27200	19.8%
Winter	\$ 0.13679	\$ 0.15261	\$ 0.18066	\$ 0.20736	35.9%	\$ 0.18006	18.0%
Energy - Intermediate							
Summer	\$ 0.07004	\$ 0.08153	\$ 0.03294	\$ 0.05964	-26.8%	\$ 0.09220	13.1%
Winter	\$ 0.07098	\$ 0.08253	\$ 0.03379	\$ 0.06049	-26.7%	\$ 0.09343	13.2%
Energy - Off-Peak							
Summer	\$ 0.04149	\$ 0.05113	\$ 0.02180	\$ 0.04850	-5.1%	\$ 0.05462	6.8%
Winter	\$ 0.04295	\$ 0.05268	\$ 0.02363	\$ 0.05033	-4.5%	\$ 0.05654	7.3%

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.

Source: Direct Testimony of David G. Prazak, Table 6 – Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Company's Current and Proposed Rates and Recommended Rates

Witness: Dismukes
Case No. PU-17-398
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Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule Large General Service- Secondary Service							
Monthly Customer Charge	\$ 40.00	\$ 42.60	\$ 215.90	\$ 215.90	406.8%	\$ 44.25	3.9%
Facilities Charge < 1,000 kW	\$ 0.30	\$ 0.32	\$ 0.76	\$ 0.76	137.9%	\$ 0.30	-6.1%
Facilities Charge >= 1,000 kW	\$ 0.15	\$ 0.16	\$ 0.56	\$ 0.56	250.6%	\$ 0.15	-6.1%
Demand per kW							
Summer	\$ 7.29	\$ 7.76	\$ 11.30	\$ 11.30	45.6%	\$ 8.16	5.1%
Winter	\$ 5.61	\$ 5.97	\$ 8.33	\$ 8.33	39.4%	\$ 6.28	5.1%
Kilowatt-hour charge							
First 700,000 kWh (changing to All kWh)			.				
Summer	\$ 0.05115	\$ 0.06002	\$ 0.02907	\$ 0.05513	-8.2%	\$ 0.06722	12.0%
Winter	\$ 0.05165	\$ 0.06056	\$ 0.02977	\$ 0.05583	-7.8%	\$ 0.06788	12.1%
Excess kWh							
Summer	\$ 0.04715	\$ 0.05576	N/A			\$ 0.06197	11.1%
Winter	\$ 0.04761	\$ 0.05625	N/A			\$ 0.06257	11.2%
Schedule Large General Service- Primary Service							
Monthly Customer Charge	\$ 40.00	\$ 42.60	\$ 282.00	\$ 282.00	562.0%	\$ 44.25	3.9%
Facilities Charge	\$ 0.11	\$ 0.12	\$ 0.48	\$ 0.48	309.8%	\$ 0.11	-6.1%
Demand per kW							
Summer	\$ 7.24	\$ 7.71	\$ 11.06	\$ 11.06	43.5%	\$ 8.10	5.0%
Winter	\$ 5.57	\$ 5.93	\$ 8.27	\$ 8.27	39.4%	\$ 6.23	5.0%
Kilowatt-hour charge							
First 700,000 kWh (changing to All kWh)							
Summer	\$ 0.05095	\$ 0.05981	\$ 0.02896	\$ 0.05502	-8.0%	\$ 0.06723	12.4%
Winter	\$ 0.05141	\$ 0.06030	\$ 0.02947	\$ 0.05553	-7.9%	\$ 0.06784	12.5%
Excess kWh							
Summer	\$ 0.04695	\$ 0.05555	N/A			\$ 0.06195	11.5%
Winter	\$ 0.04737	\$ 0.05600	N/A			\$ 0.06251	11.6%
Schedule Real Time Pricing- Primary Service							
Monthly Customer Charge	\$ 199.00	\$ 211.92	\$ 282.00	\$ 282.00	33.1%	\$ 220.13	3.9%

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.

Source: Direct Testimony of David G. Prazak, Table 6 – Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Company's Current and Proposed Rates and Recommended Rates

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-8
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Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule Large General Service Time of Day							
Secondary Service							
Monthly Customer Charge	\$ 60.00	\$ 63.90	\$ 215.90	\$215.90	237.9%	\$ 66.37	3.9%
Facilities Charge < 1,000 kW	\$ 0.30	\$ 0.32	\$ 0.76	\$0.76	137.9%	\$ 0.30	-6.1%
Facilities Charge >= 1,000 kW	\$ 0.15	\$ 0.16	\$ 0.57	\$0.57	256.8%	\$ 0.15	-6.1%
Demand per kW							
On-Peak							
Summer	\$ 5.75	\$ 6.12	\$ 7.86	\$ 7.86	28.4%	\$ 6.46	5.5%
Winter	\$ 4.42	\$ 4.71	\$ 5.13	\$ 5.13	9.0%	\$ 4.97	5.5%
Shoulder							
Summer	\$ 1.59	\$ 1.69	\$ 3.44	\$ 3.44	103.2%	\$ 1.79	5.5%
Winter	\$ 1.22	\$ 1.30	\$ 3.20	\$ 3.20	146.3%	\$ 1.37	5.5%
Kilowatt-hour charge							
Energy - On-Peak							
Summer	\$ 0.08150	\$ 0.09234	\$ 0.04485	\$ 0.07091	-23.2%	\$ 0.10714	16.0%
Winter	\$ 0.07314	\$ 0.08344	\$ 0.03929	\$ 0.06535	-21.7%	\$ 0.09615	15.2%
Energy - Shoulder							
Summer	\$ 0.06247	\$ 0.07208	\$ 0.03412	\$ 0.06018	-16.5%	\$ 0.08213	13.9%
Winter	\$ 0.05949	\$ 0.06890	\$ 0.03500	\$ 0.06106	-11.4%	\$ 0.07821	13.5%
Energy - Off-Peak							
Summer	\$ 0.03721	\$ 0.04518	\$ 0.02258	\$ 0.04864	7.7%	\$ 0.04892	8.3%
Winter	\$ 0.04199	\$ 0.05027	\$ 0.02448	\$ 0.05054	0.5%	\$ 0.05520	9.8%

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.

Source: Direct Testimony of David G. Prazak, Table 6 – Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Company's Current and Proposed Rates and Recommended Rates

Witness: Dismukes
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Description	Company's Present Rate		With Riders	Company's Proposed Rate		With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Standby Service - Option A: Firm									
Transmission Service									
Monthly Customer Charge	\$	199.00	\$	199.00	\$	304.33	\$304.33	52.9%	\$ 220.13 10.6%
Reservation Charge per kW of Contracted Backup									
Summer	\$	0.81704	\$	0.81704	\$	0.58422	\$ 0.58422	-28.5%	\$ 0.92665 13.4%
Winter	\$	0.09254	\$	0.09254	\$	0.19898	\$ 0.19898	115.0%	\$ 0.10495 13.4%
Metered Demand per day per kW On-Peak Backup									
Summer	\$	0.35865	\$	0.35865	\$	0.48812	\$ 0.48812	36.1%	\$ 0.40676 13.4%
Winter	\$	0.28694	\$	0.28694	\$	0.37420	\$ 0.37420	30.4%	\$ 0.32543 13.4%
Kilowatt-hour charge									
Energy - On-Peak									
Summer	\$	0.07900	\$	0.07900	\$	0.04184	\$ 0.04184	-47.0%	\$ 0.07938 0.5%
Winter	\$	0.07063	\$	0.07063	\$	0.03613	\$ 0.03613	-48.8%	\$ 0.08920 26.3%
Energy - Shoulder									
Summer	\$	0.06066	\$	0.06066	\$	0.03210	\$ 0.03210	-47.1%	\$ 0.06464 6.6%
Winter	\$	0.05752	\$	0.05752	\$	0.03247	\$ 0.03247	-43.6%	\$ 0.07265 26.3%
Energy - Off-Peak									
Summer	\$	0.03635	\$	0.03635	\$	0.02140	\$ 0.02140	-41.1%	\$ 0.04574 25.8%
Winter	\$	0.04070	\$	0.04070	\$	0.02292	\$ 0.02292	-43.7%	\$ 0.05140 26.3%

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.

Source: Direct Testimony of David G. Prazak, Table 6 – Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Company's Current and Proposed Rates and Recommended Rates

Witness: Dismukes
Case No. PU-17-398
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Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule Irrigation Service - Option 1							
Non-Time-of-Use							
Monthly Customer Charge	\$ 1.00	\$ 1.06	\$ 24.30	\$24.30	2181.9%	\$ 1.11	3.9%
Kilowatt-hour charge							
Summer	\$ 0.06896	\$ 0.07311	\$ 0.05552	\$ 0.07835	7.2%	\$ 0.08629	18.0%
Winter	\$ 0.05145	\$ 0.05446	\$ 0.03652	\$ 0.05935	9.0%	\$ 0.06438	18.2%
Schedule Irrigation Service - Option 2							
Monthly Customer Charge	\$ 5.00	\$ 5.32	\$ 24.30	\$24.30	356.4%	\$ 5.53094	3.9%
Kilowatt-hour charge							
Energy - Declared-Peak							
Summer	\$ 0.14450	\$ 0.15355	\$ 0.17685	\$ 0.19968	30.0%	\$ 0.18005	17.3%
Winter	\$ 0.08760	\$ 0.09296	\$ 0.14297	\$ 0.16580	78.4%	\$ 0.10915	17.4%
Energy - Intermediate							
Summer	\$ 0.05441	\$ 0.05762	\$ 0.04155	\$ 0.06438	11.7%	\$ 0.06780	17.7%
Winter	\$ 0.05111	\$ 0.05410	\$ 0.04217	\$ 0.06500	20.1%	\$ 0.06369	17.7%
Energy - Off-Peak							
Summer	\$ 0.02642	\$ 0.02781	\$ 0.01802	\$ 0.04085	46.9%	\$ 0.03292	18.4%
Winter	\$ 0.02612	\$ 0.02749	\$ 0.02015	\$ 0.04298	56.3%	\$ 0.03255	18.4%

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.

Source: Direct Testimony of David G. Prazak, Table 6 – Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Company's Current and Proposed Rates and Recommended Rates

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-8
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Description	Company's Present Rate		With Riders		Company's Proposed Rate		With Riders		Increase from Present Rate		Alternative Rates		Increase from Present Rate	
Outdoor Lighting - Metered - Energy Only														
Monthly Customer Charge	\$	2.00	\$	2.13	\$	2.00	\$	2.00	-6.1%	\$	2.00		-6.1%	
Kilowatt-hour charge														
Summer	\$	0.06978	\$	0.07876	\$	0.07047	\$	0.09625	22.2%	\$	0.08977		14.0%	
Winter	\$	0.06978	\$	0.07876	\$	0.07047	\$	0.09625	22.2%	\$	0.08977		14.0%	
Outdoor Lighting - Non-Metered - Energy Only														
Monthly Charge for Connected Kw	\$	23.84	\$	25.39	\$	24.08	\$	24.08	-5.2%	\$	30.39		19.7%	
Sign Lighting														
Monthly Charge for Connected Kw	\$	23.84	\$	25.39	\$	24.08	\$	24.08	-5.2%	\$	30.45		19.9%	
Outdoor Lighting - Street & Area Lighting														
MV-6	\$	7.01	\$	7.47	\$	7.12	\$	7.12	-4.6%	\$	8.74		17.0%	
MV-6PT	\$	10.00	\$	10.65	\$	10.16	\$	10.16	-4.6%	\$	12.46		17.0%	
MV-11	\$	12.70	\$	13.52	\$	12.90	\$	12.90	-4.6%	\$	15.83		17.0%	
MV-21	\$	16.72	\$	17.81	\$	16.99	\$	16.99	-4.6%	\$	20.84		17.0%	
MV-35	\$	24.53	\$	26.12	\$	24.92	\$	24.92	-4.6%	\$	30.57		17.0%	
MV-55	\$	31.36	\$	33.40	\$	31.86	\$	31.86	-4.6%	\$	39.08		17.0%	
MA-8	\$	8.46	\$	9.01	\$	8.59	\$	8.59	-4.6%	\$	10.54		17.0%	
MA-14	\$	16.10	\$	17.15	\$	16.36	\$	16.36	-4.6%	\$	20.06		17.0%	
MA-20	\$	18.38	\$	19.57	\$	18.67	\$	18.67	-4.6%	\$	22.90		17.0%	
MA-36	\$	18.00	\$	19.17	\$	18.29	\$	18.29	-4.6%	\$	22.43		17.0%	
MA-110	\$	38.41	\$	40.90	\$	39.02	\$	39.02	-4.6%	\$	47.86		17.0%	
HPS-9	\$	7.52	\$	8.01	\$	7.64	\$	7.64	-4.6%	\$	9.37		17.0%	
HPS-9PT	\$	9.72	\$	10.35	\$	9.87	\$	9.87	-4.6%	\$	12.11		17.0%	
HPS-14	\$	11.71	\$	12.47	\$	11.90	\$	11.90	-4.6%	\$	14.59		17.0%	
HPS-14PT	\$	12.53	\$	13.34	\$	12.73	\$	12.73	-4.6%	\$	15.61		17.0%	
HPS-19	\$	13.61	\$	14.49	\$	13.83	\$	13.83	-4.6%	\$	16.96		17.0%	
HPS-23	\$	15.40	\$	16.40	\$	15.65	\$	15.65	-4.6%	\$	19.19		17.0%	
HPS-44	\$	19.01	\$	20.24	\$	19.31	\$	19.31	-4.6%	\$	23.69		17.0%	
UHPS23	\$	17.99	\$	19.16	\$	18.11	\$	18.11	-5.5%	\$	22.42		17.0%	
UHPS9	\$	9.86	\$	10.50	\$	10.10	\$	10.10	-3.8%	\$	12.29		17.0%	
UMV6	\$	8.97	\$	9.55	\$	9.58	\$	9.58	0.3%	\$	11.18		17.0%	
Seasonal Charge	\$	10.80	\$	11.50	\$	32.79	\$	32.79	185.1%	\$	13.46		17.0%	
Outdoor Lighting - Flood Lighting														
400MV-F	\$	17.35	\$	18.48	\$	17.63	\$	17.63	-4.6%	\$	21.68		17.4%	
400MA-F	\$	18.49	\$	19.69	\$	18.78	\$	18.78	-4.6%	\$	23.11		17.4%	
400HPS-F	\$	18.90	\$	20.13	\$	19.20	\$	19.20	-4.6%	\$	23.62		17.4%	
1000MV-F	\$	30.44	\$	32.42	\$	30.93	\$	30.93	-4.6%	\$	38.04		17.4%	
1000MA-F	\$	32.11	\$	34.19	\$	32.62	\$	32.62	-4.6%	\$	40.13		17.4%	
1M-HPSF	\$	37.32	\$	39.74	\$	37.91	\$	37.91	-4.6%	\$	46.64		17.4%	
U1M-MAF	\$	39.44	\$	42.00	\$	21.66	\$	21.66	-48.4%	\$	49.29		17.4%	
Underground Service	\$	1.96	\$	2.09	\$	2.46	\$	2.46	17.9%	\$	2.45		17.4%	

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.

Source: Direct Testimony of David G. Prazak, Table 6 – Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Company's Current and Proposed Rates and Recommended Rates

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-8
Page 9 of 11

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Municipal Pumping - Secondary Service							
Monthly Customer Charge	\$ 4.00	\$ 4.26	\$ 26.50	\$ 26.50	522.1%	\$ 4.42	3.9%
Facilities Charge	\$ 4.00	\$ 4.26	\$ 0.65	\$ 0.65	-84.7%	\$ 4.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.06523	\$ 0.07509	\$ 0.05159	\$ 0.07764	3.4%	\$ 0.08562	14.0%
Winter	\$ 0.05950	\$ 0.06898	\$ 0.03490	\$ 0.06095	-11.7%	\$ 0.07809	13.2%
Civil Defense - Fire Sirens							
Monthly Customer Charge	\$ 1.00	\$ 1.06	\$ 1.22	\$ 1.22	14.6%	\$ 1.10619	3.9%
Load Charge	\$ 0.53193	\$ 0.56646	\$ 0.42962	\$ 0.42962	-24.2%	\$ 0.66459	17.3%
Water Heating - Controlled Service							
Monthly Customer Charge	\$ 1.00	\$ 1.06	\$ 4.00	\$ 4.00	\$ 2.76	\$ 1.11	3.9%
Facilities Charge	\$ 1.00	\$ 1.06	\$ 2.00	\$ 2.00	\$ 0.88	\$ 1.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.05773	\$ 0.06369	\$ 0.03317	\$ 0.05818	-8.6%	\$ 0.07359	15.6%
Winter	\$ 0.05638	\$ 0.06225	\$ 0.02868	\$ 0.05369	-13.7%	\$ 0.07187	15.5%

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.

Source: Direct Testimony of David G. Prazak, Table 6 – Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Company's Current and Proposed Rates and Recommended Rates

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-8
Page 10 of 11

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Controlled Service - Interruptible Load Rider CT Metering - Option 1							
Monthly Customer Charge	\$ 4.00	\$ 4.26	\$ 20.20	\$ 20.20	374.2%	\$ 4.42	3.9%
Facilities Charge	\$ 0.08	\$ 0.09	\$ 0.76	\$ 0.76	792.1%	\$ 0.08	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.03166	\$ 0.03690	\$ 0.01060	\$ 0.03633	-1.6%	\$ 0.04213	14.2%
Winter	\$ 0.03044	\$ 0.03561	\$ 0.01005	\$ 0.03578	0.5%	\$ 0.04050	13.8%
Penalty Kilowatt-hour charge							
Summer	\$ 0.39448	\$ 0.42328	\$ 0.41350	\$ 0.43923	3.8%	\$ 0.41350	-2.3%
Winter	\$ 0.12726	\$ 0.13871	\$ 0.14322	\$ 0.16895	21.8%	\$ 0.14322	3.3%
Controlled Service - Interruptible Load Rider CT Metering - Option 2							
Monthly Customer Charge	\$ 5.00	\$ 5.32	\$ 20.20	\$ 20.20	279.4%	\$ 5.53	3.9%
Facilities Charge	\$ 0.08	\$ 0.09	\$ 0.76	\$ 0.76	792.1%	\$ 0.08	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.03336	\$ 0.03871	\$ 0.01060	\$ 0.03633	-6.2%	\$ 0.04435	14.5%
Winter	\$ 0.03208	\$ 0.03735	\$ 0.01005	\$ 0.03578	-4.2%	\$ 0.04264	14.2%
Control Period Demand							
Summer	\$ 7.29	\$ 7.76	\$ 11.38	\$ 11.38	46.6%	\$ 8.44	8.7%
Winter	\$ 5.61	\$ 5.97	\$ 6.25	\$ 6.25	4.6%	\$ 6.49	8.7%
Controlled Service - Interruptible Load Rider Self-Contained Metering							
Monthly Customer Charge	\$ 2.00	\$ 2.13	\$ 8.50	\$ 8.50	299.1%	\$ 2.21	3.9%
Facilities Charge	\$ 5.00	\$ 5.32	\$ 11.70	\$ 11.70	119.7%	\$ 5.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.03659	\$ 0.04215	\$ 0.01111	\$ 0.03683	-12.6%	\$ 0.04888	16.0%
Winter	\$ 0.03451	\$ 0.03994	\$ 0.01037	\$ 0.03609	-9.6%	\$ 0.04610	15.4%
Penalty Kilowatt-hour charge							
Summer	\$ 0.38606	\$ 0.41431	\$ 0.41350	\$ 0.43922	6.0%	\$ 0.41350	-0.2%
Winter	\$ 0.12924	\$ 0.14082	\$ 0.16537	\$ 0.19110	35.7%	\$ 0.16537	17.4%

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.

Source: Direct Testimony of David G. Prazak, Table 6 – Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Company's Current and Proposed Rates and Recommended Rates

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-8
Page 11 of 11

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Controlled Service - Deferred Load Rider							
Monthly Customer Charge	\$ 3.00	\$ 3.19	\$ 8.80	\$ 8.80	175.5%	\$ 3.32	3.9%
Facilities Charge	\$ 4.00	\$ 4.26	\$ 11.60	\$ 11.60	172.3%	\$ 4.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.05154	\$ 0.05831	\$ 0.02762	\$ 0.05355	-8.2%	\$ 0.06659	14.2%
Winter	\$ 0.05002	\$ 0.05669	\$ 0.02516	\$ 0.05110	-9.9%	\$ 0.06463	14.0%
Penalty Kilowatt-hour charge							
Summer	\$ 0.33802	\$ 0.36338	\$ 0.35916	\$ 0.38510	6.0%	\$ 0.35916	-1.2%
Winter	\$ 0.11510	\$ 0.12599	\$ 0.16537	\$ 0.19131	51.8%	\$ 0.16537	31.3%
Fixed Time of Service Rider - Self-Contained Metering							
Monthly Customer Charge	\$ 1.00	\$ 1.06	\$ 6.70	\$ 6.70	529.2%	\$ 1.11	3.9%
Facilities Charge	\$ 3.00	\$ 3.19	\$ 6.00	\$ 6.00	87.8%	\$ 3.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.01626	\$ 0.02074	\$ 0.01525	\$ 0.04118	98.6%	\$ 0.03859	86.1%
Winter	\$ 0.03325	\$ 0.03883	\$ 0.01687	\$ 0.04280	10.2%	\$ 0.04085	5.2%
Penalty Kilowatt-hour charge							
Summer	\$ 0.05676	\$ 0.06044	\$ 0.06736	\$ 0.09330	54.3%	\$ 0.06736	11.4%
Winter	\$ 0.03605	\$ 0.03839	\$ 0.04602	\$ 0.07196	87.4%	\$ 0.04602	19.9%
Fixed Time of Service Rider - CT Metering							
Monthly Customer Charge	\$ 1.50	\$ 1.60	\$ 6.70	\$ 6.70	319.4%	\$ 1.66	3.9%
Facilities Charge	\$ 19.00	\$ 20.23	\$ 38.00	\$ 38.00	87.8%	\$ 19.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.01626	\$ 0.02074	\$ 0.01525	\$ 0.04118	98.6%	\$ 0.03810	83.7%
Winter	\$ 0.03325	\$ 0.03883	\$ 0.01687	\$ 0.04280	10.2%	\$ 0.04034	3.9%
Penalty Kilowatt-hour charge							
Summer	\$ 0.05676	\$ 0.06387	\$ 0.06736	\$ 0.09330	46.1%	\$ 0.06736	5.5%
Winter	\$ 0.03605	\$ 0.04181	\$ 0.04602	\$ 0.07196	72.1%	\$ 0.04602	10.1%

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.

Source: Direct Testimony of David G. Prazak, Table 6 – Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Comparison of Current and Proposed Customer Charges

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-9
Page 1 of 1

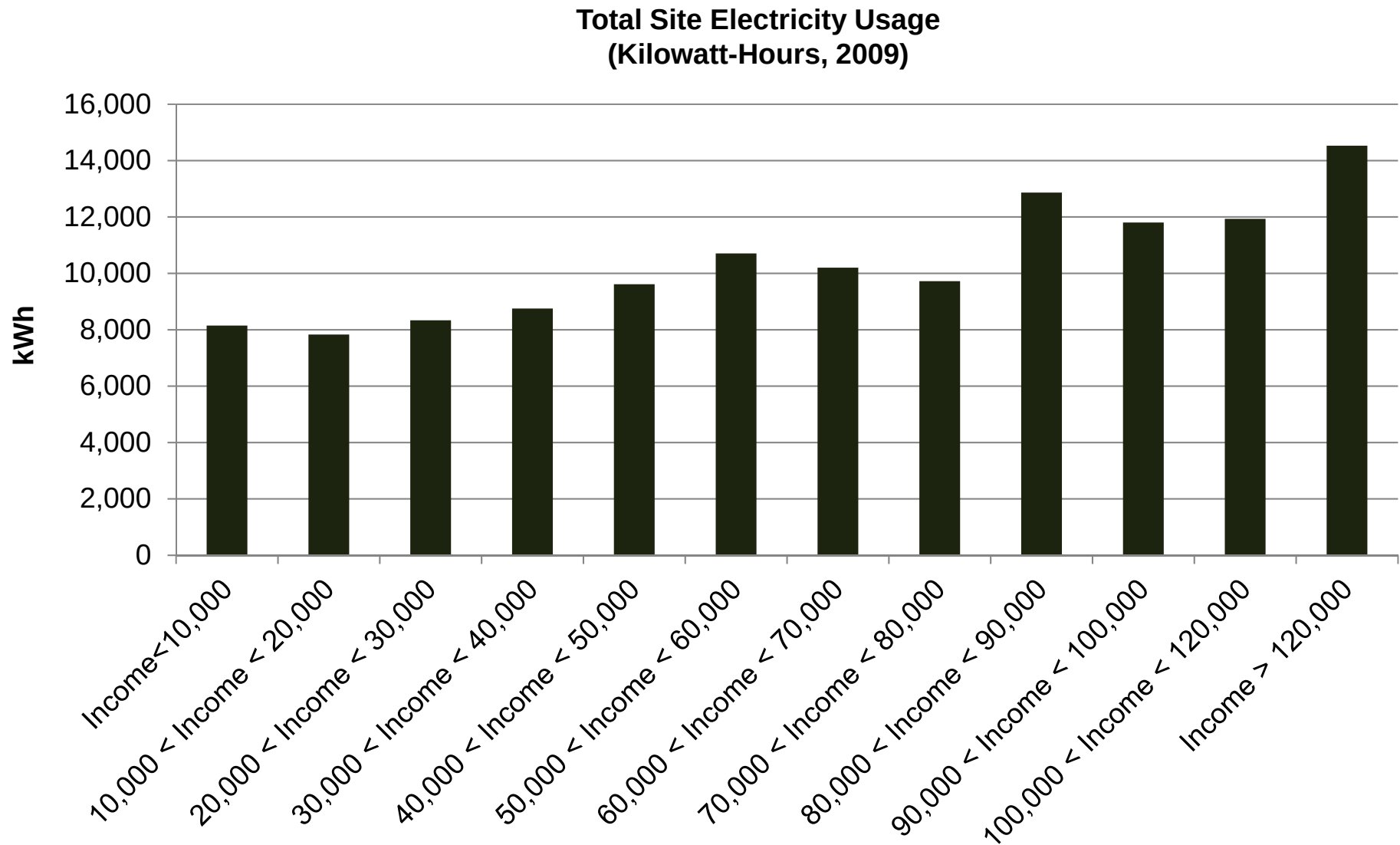
	Residential Service		Farm Services		General Service			Large General Service	
	Residential Service	Residential Demand Control Service	Farm Service Single Phase	Farm Service Three Phase	Sm. General Service	General Service (Secondary)	General Service TOU	Large General Service Secondary	Large General Service Time of Day Primary
Current Charge	\$8.00	\$18.38	\$12.00	\$12.00	\$13.00	\$12.00	\$16.00	\$40.00	\$60.00
Proposed Charge	\$15.23	\$20.10	\$17.40	\$17.40	\$24.90	\$31.90	\$219.00	\$215.90	\$282.00
Percentage Difference	90.4%	9.4%	45.0%	45.0%	91.5%	165.8%	1268.8%	439.8%	370.0%

	Outdoor Lighting		Controlled Service			Irrigation Option 1	Irrigation Option 2	Municipal Pumping	Civil Defense	Water Heating	Deferred Load Service	Fixed Time of Service Secondary
	Outdoor Lighting Metered	Outdoor Lighting Non-metered	Controlled Service Interruptible Large #1	Controlled Service Interruptible Large #2	Controlled Service Interruptible small							
Current Charge	\$2.00	\$0.00	\$4.00	\$5.00	\$2.00	\$1.00	\$5.00	\$4.00	\$1.00	\$1.00	\$3.00	\$1.50
Proposed Charge	\$2.00	\$0.00	\$20.20	\$20.20	\$8.50	\$24.30	\$24.30	\$26.50	\$1.22	\$4.00	\$8.80	\$6.70
Percentage Difference	0.0%	0.0%	405.0%	304.0%	325.0%	2330.0%	386.0%	562.5%	22.0%	300.0%	193.3%	346.7%

Source: Direct Testimony of David G. Prazak, Table 6 through Table 24.

Electricity Usage by Income

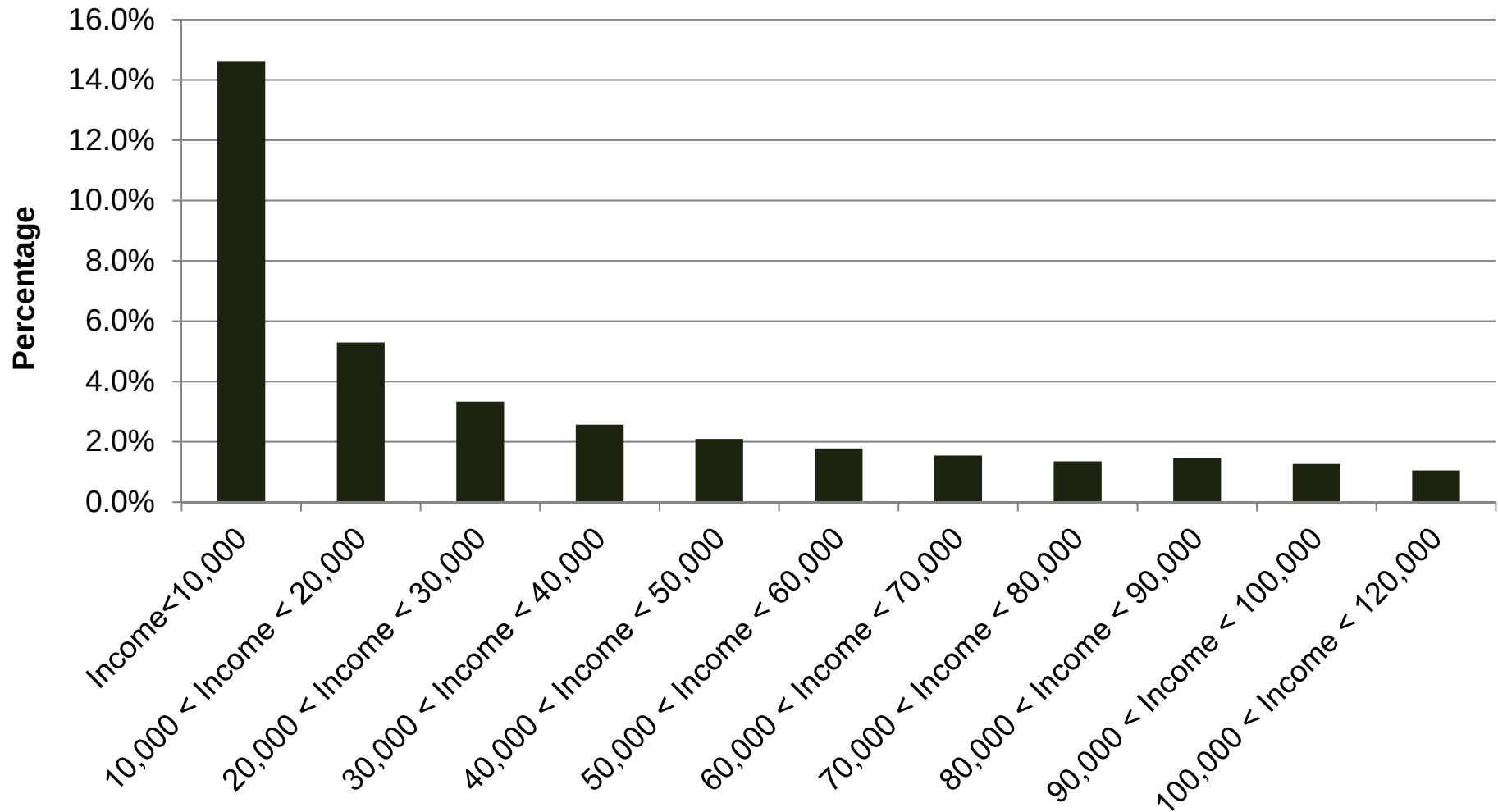
Witness: Dismukes
Case No. PU-17-398
Exhibit DED-10
Page 1 of 1



Source: Energy Information Administration, Residential Electricity Consumption Survey ("RECS")

Spending on Electricity as Percentage of Income

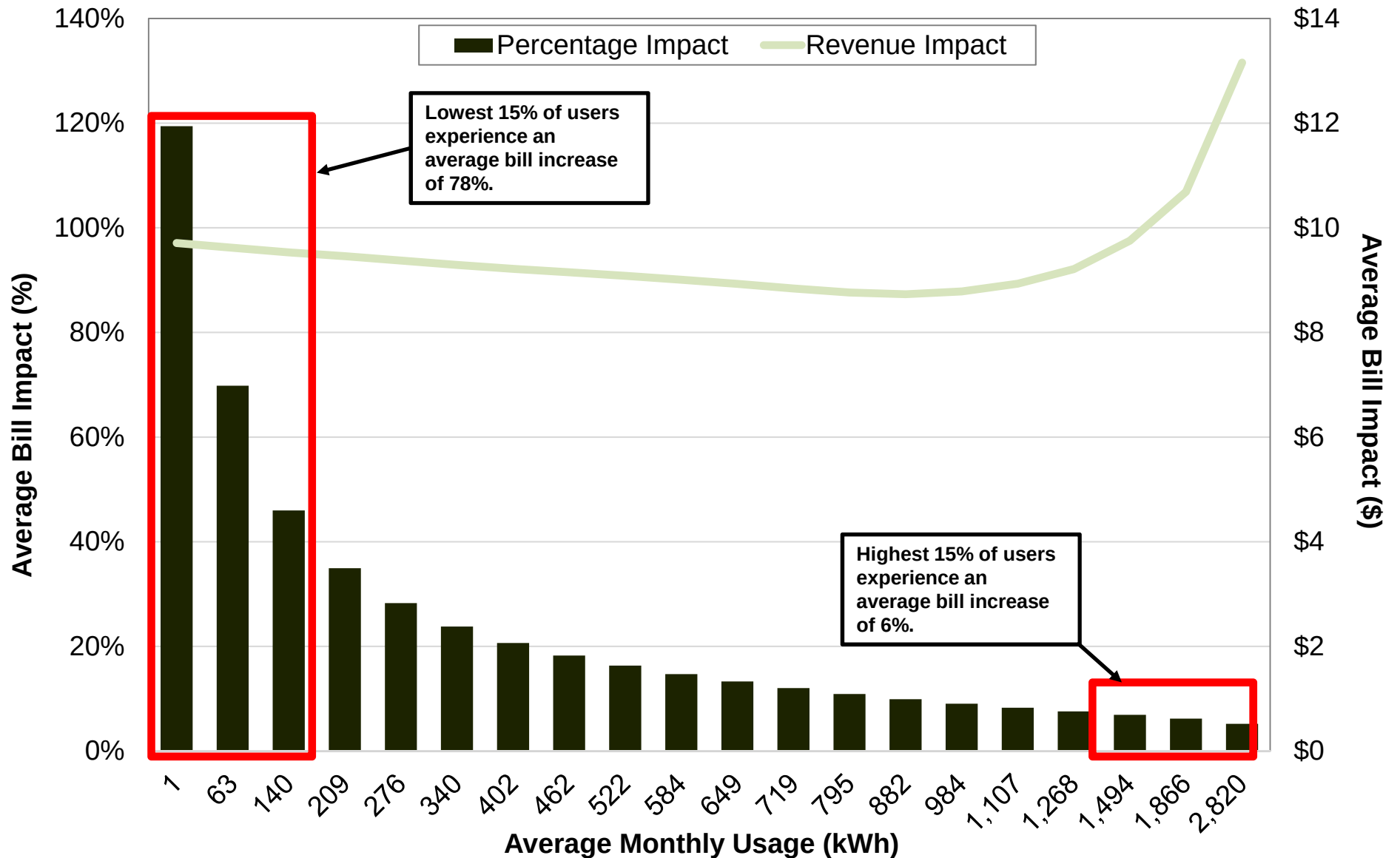
Witness: Dismukes
Case No. PU-17-398
Exhibit DED-11
Page 1 of 1



Source: Energy Information Administration, Residential Electricity Consumption Survey ("RECS")

Bill Impact by Usage: Residential Service

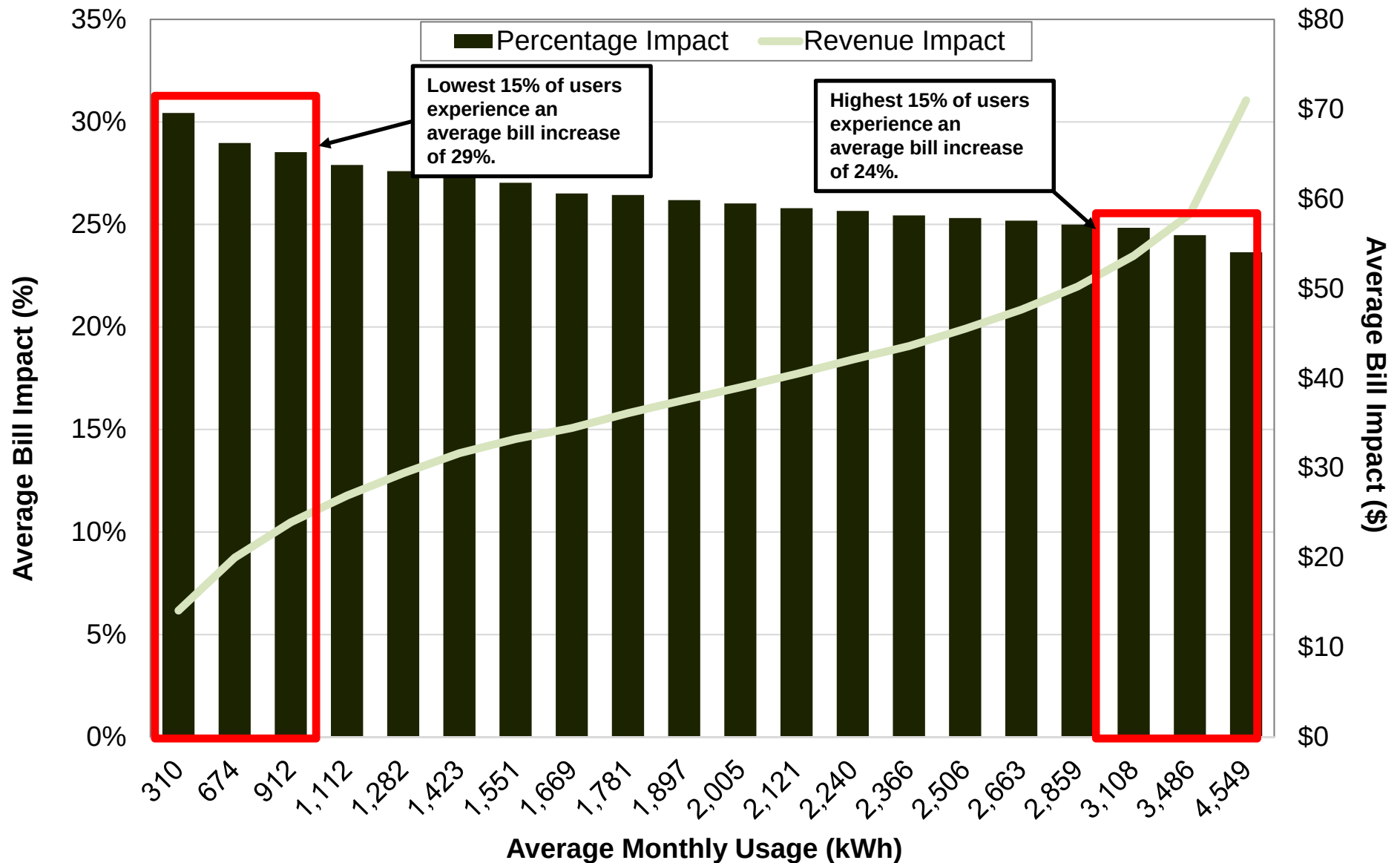
Witness: Dismukes
Case No. PU-17-398
Exhibit DED-12
Page 1 of 3



Source: Company response to ND-PSC-04.18

Bill Impact by Usage: Residential Demand Control

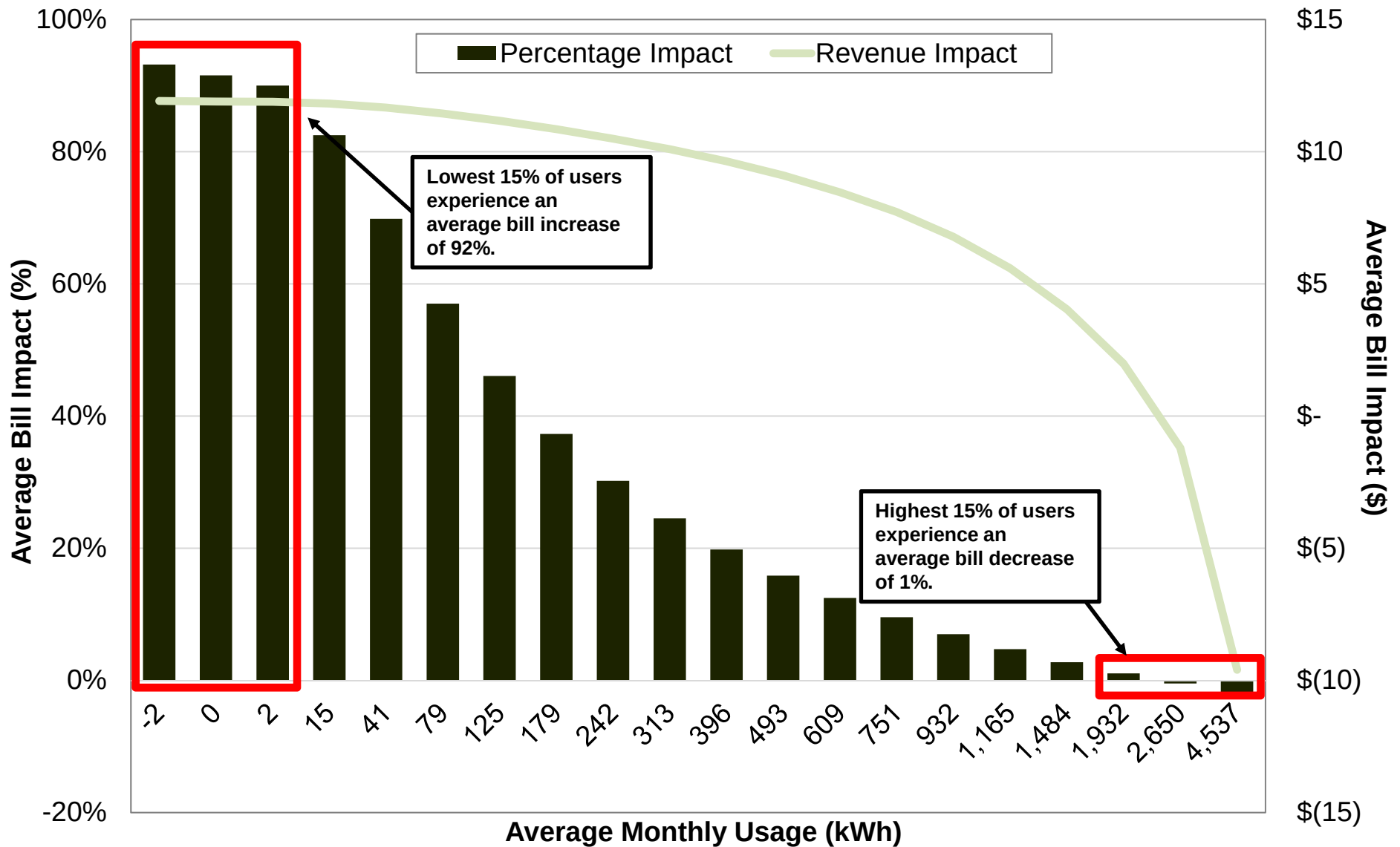
Witness: Dismukes
Case No. PU-17-398
Exhibit DED-12
Page 2 of 3



Source: Company response to ND-PSC-04.18

Bill Impact by Usage: Small General Service

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-12
Page 3 of 3



Comparison of Customer-Related Costs

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-13
Page 1 of 1

	Residential	Farm Service	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interrupt	Controlled Service Deferred
<u>Customer-Related Costs per Company CCOSS</u>										
Total Customer-Related Costs	\$11,716,811	\$293,338	\$3,860,188	\$109,913	\$19,548	\$26,225	\$160,964	\$324,160	\$490,202	\$75,271
Average Number of Customers	46,204	937	11,164	261	35	82	554	35	246	39
Monthly Customer-Related Costs/Customer	\$21.13	\$26.09	\$28.81	\$35.09	\$46.54	\$26.65	\$24.21	\$771.81	\$166.06	\$160.84
Customer Charge Revenues	\$ 4,975,773	\$ 160,541	\$ 1,848,558	\$ 138,625	\$ 893	\$ 2,281	\$ 28,532	\$ 68,012	\$ 198,502	\$ 28,544
Monthly Customer Charge Revenue/Customer	\$ 8.97	\$ 14.28	\$ 13.80	\$ 44.26	\$ 2.13	\$ 2.32	\$ 4.29	\$ 161.93	\$ 67.24	\$ 60.99
Relationship of Customer Charge Revenues to Customer-Related Costs	42%	55%	48%	126%	5%	9%	18%	21%	40%	38%

Source: Company's Response to DR ND-PSC-04.23, Attachment 1; and Direct Testimony of David G. Prazak, Exhibit DGP-1.

Customer Charge Survey

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-14
Page 1 of 1

State	Company	Residential Rate	Small Commercial Rate
IA	Interstate Power and Light Co ¹	\$13.50	\$24.00
IA	MidAmerican Energy Co ¹	\$8.50	\$10.00
MN	ALLETE, Inc. ^{1,2}	\$8.00	\$10.50
MN	Northern States Power Co	\$8.00	\$10.00
MN	Otter Tail Power Co ¹	\$9.75	\$27.00
MT	Montana-Dakota Utilities Co ³	\$5.17	\$15.21
MT	NorthWestern Energy LLC ¹	\$4.10	\$7.35
ND	Montana-Dakota Utilities Co ³	\$13.99	\$25.55
ND	Northern States Power Co ⁴	\$14.50	\$16.75
ND	Otter Tail Power Co ¹	\$8.00	\$12.00
SD	Montana-Dakota Utilities Co ³	\$7.51	\$15.51
SD	MidAmerican Energy Co ¹	\$8.00	\$10.00
SD	Northern States Power Co	\$8.25	\$9.00
SD	NorthWestern Energy ¹	\$6.00	\$10.00
SD	Otter Tail Power Co ¹	\$8.00	\$12.00
SD	Black Hills Power, Inc. ¹	\$9.25	\$12.00
WI	Madison Gas & Electric Co ³	\$19.00	\$23.93
WI	Northern States Power Co ⁴	\$17.00	\$17.00
WI	Northwestern Wisconsin Elec Co ¹	\$11.00	\$16.00
WI	Superior Water and Light Co ¹	\$9.00	\$10.00
WI	Wisconsin Electric Power Co ^{1,3}	\$16.00	\$16.00
WI	Wisconsin Power & Light Co ^{1,3}	\$15.00	\$17.00
WI	Wisconsin Public Service Corp	\$21.00	\$27.63
WY	Cheyenne Light Fuel & Power d/b/a Black Hills Energy ¹	\$13.00	\$16.00
WY	Montana-Dakota Utilities Co ³	\$25.00	\$29.99
WY	PacifiCorp ⁵	\$20.00	\$24.25
WY	Black Hills Power, Inc. ¹	\$15.50	\$28.00

¹The lowest General Service rate is used due to lack of Small Commercial Service rates on companies' tariffs.

²Residential and Commercial rates pulled from Minnesota Power, a division of ALLETE. Seasonal residential charge is \$8.80.

³Rates are daily rates multiplied by 365 and divided by 12 for monthly average.

⁴Residential and Commercial charges are pulled from Xcel Energy, which owns Northern States Power Co.

⁵Residential and Commercial charges are pulled from Rocky Mountain Power in Wyoming, a division of PacifiCorp.

Exhibit DED-15
Cited Responses to Information Requests

This exhibit presents a compilation of the documents and responses to discovery requests cited in the testimony of David E. Dismukes, Ph.D. on Behalf of the North Dakota Public Service Commission as follows:

PSC-01.30	3
PSC-04.17	5
PSC-04.25	8
PSC-04.25, Attachment 1	11
PSC-04.31	27
PSC-04.31, Attachment 1	29
PSC-06.20	128
PSC-08.05	131
PSC-09.06	134
PSC-09.07	137
PSC-09.12	140
PSC-09.12, Attachment 1	143
PSC-09.14	145
PSC-10.01	148
PSC-11.20	151
PSC-11.23	153
PSC-13.01	157
PSC-13.02	160
PSC-13.03	163
PSC-14.01 (NOT PUBLIC)	165
PSC-14.01, Attachment 4 (NOT PUBLIC)	169
PSC-17.25	185
PSC-18.22	188
PSC-18.24	192
PSC-18.25	195
PSC-18.28	197
PSC-18.28, Attachment 1	200

PSC-18.30	208
PSC-18.31	212
MLEC-209	215

PSC-01.30

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Sara Cardwell

Date Received: 11/29/2017

Date Due: 12/13/2017

Date of Response: 12/12/2017

Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

In looking at your Residential Time of Day Pilot, do you believe it is appropriate to just end the pilot and move residential customers back to the standard schedule? How would this work for customers who may be saving significant dollars by being on the time of use schedule and may have installed equipment to facilitate savings?

Attachments: 0

Response:

OTP intends to convert the pilot program to a permanent program based on the outcomes of our three objectives (See Prazak Direct, p 55). There is likely to be a lag between the end of the pilot and implementation of the permanent program where pilot customers will be moved back to standard rates. We believe this is appropriate because the lag will be short, and participation in the pilot will be voluntary with full disclosure to participants regarding the temporary nature of the pilot program. Customer satisfaction/engagement are an important part of our objectives.

PSC-04.17

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Svetlana Fedje, Pricing Analyst - (218) 739-8799

Data Request:

Customer Charges

- a. For each customer class, list each type of cost included in the current and proposed customer charges.
- b. For each type of cost included in the current and proposed customer charges, provide the Company's rationale for including each cost type.
- c. Is the Company proposing any changes to the types of costs included in the customer charges?
- d. Provide all analyses conducted by or for the Company that provides the cost support of the Company's current and proposed customer charges for each class. Provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.
- e. If no such analysis was conducted, provide a detailed explanation of the Company's justification of its customer charge proposals.

Attachments: 0

Response:

- a) The components of the Customer Charge do not change for any customer class and are defined per the tariff sheet glossary as “Part of the monthly basic Distribution charge to partially cover costs for billing, Meter Reading, equipment Service line maintenance and equipment.” There are three main components of the Customer Charge:

- a) Investment - Meter Costs
- b) Investment - Meter Service Drops
- c) O&M - Meter, Customer Accounts Expenses, Customer Service

The type of costs that are included in the customer charges are detailed in the Marginal Cost Study which is presented in Marginal Cost Study spreadsheet on the tab “MONTH CUST COSTS SUM T33”. Please refer to Attachment 42 Vol 2b DGP-1 Schedule 2 2018 Marginal Cost Study to DR ND-PSC-01.1.to see the spreadsheet.

Current Customer Charges were approved in the last case by the ND PUC at a percent of the Marginal Costs. In this case, OTP is asking for close to 100% of Marginal Costs to determine new Customer Charges

- b) Each cost type is an important component of the Customer Charge.
 - a) Investment - Meter Costs. - Meters are necessary to monitor Customers usage.
 - b) Investment - Meter Service Drops. - Meter Service Drop is an unavoidable expense of the service
 - c) O&M - Meter, Customer Accounts Expenses, Customer Service Integral part of providing Customer with accurate and timely billing information.
- c) Otter Tail is not proposing any changes to the components of the Customer Charge. However, Otter Tail is proposing making new customer Charges as close to the calculated Marginal Costs as possible.
- d) Annual Marginal Customer Charges are computed in the Marginal Cost Study and located in the following tabs “Annual Customer T29 P1” - “Annual Customer T29 P5”. They are calculated for each customer class and all costs are transparent in these tables. See Attachment 42 Vol 2b DGP-1 Schedule 2 2018 Marginal Cost Study to DR ND-PSC-01.1.

PSC-04.25

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 02/16/2018

Date Due: 03/05/2018

Date of Response: 03/08/2018

Responding Witness: Gina Ice, Rate Analyst

Data Request:

Provide all subsidiary studies to the Company's CCOSS. This includes all studies used to derive the allocation factors used in the CCOSS and/or used for any other purpose in the CCOSS. These include, but are not limited to special cost allocation studies. Provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Attachments: 3

Attachment 3 to DR ND-PSC-04.25.xlsx

Attachment 2 to DR ND-PSC-04.25.xlsx

Attachment 1 to DR ND-PSC-04.25.xlsx

Response:

The process OTP utilizes to calculate its allocation factors used in the CCOSS is as follows:

Input files from OTP programmers and data queried from internal data repositories are read into our SAS software and aggregated to the jurisdictional and class levels. Please refer to Attachment 1 to DR ND-PSC-04.25 for the output created by SAS, which serves as the basis for calculating the historical C, D, and E allocation factors. This information is then imported into OTP's forecasting system, Utilities International (UI). Line loss factors are applied, and forecasted values are calculated as described in the Forecast Cost Allocation Manual, Schedule 3 of Gina Ice's Direct Testimony. The forecasted factors produced by UI are used in the JCOSS and CCOSS models.

In OTP's current rate case, the use of an E8760 allocator began for class cost of service study development purposes as ordered by the Commission in OTP's last rate case. Please refer to Attachment 2 to DR ND-PSC-04.25 and Attachment 3 to DR ND-PSC-04.25 for the Excel spreadsheet support used in the derivation of the E8760 factors used to reallocate E1 and E2 jurisdictional amounts to the respective classes in the CCOSS. The resulting output is utilized in the CCOSS.

Please also refer to Attachment 1 to DR ND-PSC-04.31 for the minimum size study performed by OTP for use in allocating electric distribution plant costs.

PSC-04.25, ATTACHMENT 1

North Dakota Classes

Factor	Total	MN	ND	SD	FERC	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interrupt	Controlled Service Deferred
D-1	719,488	366,707	284,731	67,075	975	94,960	6,921	82,461	86,514	0	2,816	2,782	183	7,354	740
D-2	724,464	366,707	284,731	67,075	5,951	94,960	6,921	82,461	86,514	0	2,816	2,782	183	7,354	740
D-3	841,602	360,299	392,986	83,140	5,177	89,167	12,217	85,800	102,198	753	5,637	2,710	6,845	79,147	8,512
D-4	1,099,695	453,655	533,900	112,140	0	138,886	19,021	127,398	79,799	1,292	5,332	5,499	21,366	121,338	13,969
E-1	4,595,451	2,520,607	1,642,398	429,038	3,408	462,093	31,442	418,209	669,059	0	24,591	18,161	6,443	0	12,400
E-2	5,121,582	2,731,394	1,923,638	463,142	3,408	513,058	31,442	418,279	669,059	815	24,591	18,161	15,465	203,007	29,761
C-1	132,063	61,696	58,787	11,580	0	45,626	915	11,027	249	33	75	553	37	236	36
C-2	138,714	64,657	61,948	12,105	4	47,609	1,112	12,248	174	80	91	577	11	40	6
C-3	138,639	64,610	61,933	12,096	0	47,609	1,112	12,242	165	80	91	577	11	40	6
C-4	5,464,004	2,475,177	2,381,279	607,548	0	0	0	0	0	0	2,381,279	0	0	0	0
C-5	4,786,865	1,966,717	2,477,820	342,328	0	0	0	0	0	0	2,477,820	0	0	0	0
C-6	52,603,325	24,253,657	23,503,024	4,846,644	0	6,969,736	544,765	8,391,132	567,290	41,786	39,342	247,825	2,451,390	3,668,002	581,756
C-7	180,351	87,159	76,928	16,264	0	47,023	937	19,950	588	48	101	738	3,013	3,978	553
C-8	138,739	64,679	61,951	12,105	4	47,609	1,112	12,248	177	80	91	577	11	40	6
C-9	42,398	19,841	18,457	4,100	0	4,005	5	21	1	23	0	0	6,000	7,694	708

C1 Factor
Total Active Customers by Rate Group

	Class	Rate Group	State			System
			MN	ND	SD	
A	Residential	Group 11	46,517	42,178	8,385	97,080
		Group 12	2,319	3,448	405	6,172
		Class Total	48,836	45,626	8,790	103,252
	Farms	Group 21	1,197	915	342	2,454
		Group 22	0	0	0	0
		Group 23	0	0	0	0
		Group 30	0	0	0	0
		Class Total	1,197	915	342	2,454
	General Service	Group 31	9,707	10,322	2,052	22,081
		Group 36	17	1	0	18
		Group 41	280	704	124	1,108
		Group 48	26	0	0	26
		Class Total	10,030	11,027	2,176	23,233
	Large General Service	Group 42	12	7	3	22
		Group 43	433	240	52	725
		Group 62	11	1	0	12
		Group 63	0	1	0	1
		Class Total	456	249	55	760
	Irrigation	Group 29	194	21	13	228
		Group 37	21	12	2	35
		Class Total	215	33	15	263
	Area & Street Lighting	Group 17	3	1	4	8
		Group 28	0	0	0	0
		Group 38	47	33	29	109
		Group 49	4	1	0	5
		Group 52	0	0	0	0
		Group 61	124	40	2	166
		Class Total	178	75	35	288
	OPA	Group 51	482	553	114	1,149
		Class Total	482	553	114	1,149
	Water Heating	Group 13	43	26	5	74
		Group 24	5	4	3	12
		Group 34	9	6	4	19
		Group 46	1	1	0	2
		Class Total	58	37	12	107
	Service Interrupt	Group 14	119	94	13	226
		Group 15	0	2	0	2
		Group 25	43	50	11	104
		Group 26	2	6	0	8
		Group 32	37	60	4	101
		Group 33	2	5	0	7
		Group 44	2	10	0	12
		Group 45	2	9	2	13
		Class Total	207	236	30	473
	Service Deferred	Group 16	14	6	4	24
		Group 27	8	6	2	16
		Group 35	12	18	4	34
		Group 47	3	6	1	10
		Class Total	37	36	11	84
Sub Total			61,696	58,787	11,580	132,063

C2 Factor
Total Distribution Service Locations Factor

	Class	Rate Group	State			System
			MN	ND	SD	
A	Residential	Group 11	48,188	44,113	8,686	100,987
		Group 12	2,352	3,496	408	6,256
		Class Total	50,540	47,609	9,094	107,243
	Farms	Group 21	1,379	1,112	382	2,873
		Group 22	0	0	0	0
		Group 23	0	0	0	0
		Group 30	0	0	0	0
		Class Total	1,379	1,112	382	2,873
	General Service	Group 31	10,582	11,275	2,229	24,086
		Group 36	52	3	0	55
		Group 41	406	970	167	1,543
		Group 48	83	0	0	83
		Class Total	11,123	12,248	2,396	25,767
	Large General Service	Group 42	16	8	3	27
		Group 43	314	164	33	511
		Group 62	12	1	0	13
		Group 63	0	1	0	1
		Class Total	342	174	36	552
	Irrigation	Group 29	465	56	25	546
		Group 37	46	24	2	72
		Class Total	511	80	27	618
	Area & Street Lighting	Group 17	4	2	4	10
		Group 28				0
		Group 38	56	40	35	131
		Group 49	6	1	0	7
		Group 52				0
		Group 61	135	48	2	185
	Class Total	201	91	41	333	
	OPA	Group 51	500	577	119	1,196
		Class Total	500	577	119	1,196
	Water Heating	Group 13	16	10	2	28
		Group 24	0	0	0	0
		Group 34	4	1	1	6
		Group 46	0	0	0	0
		Class Total	20	11	3	34
	Service Interrupt	Group 14	29	14	1	44
		Group 15	0	1	0	1
		Group 25	0	2	0	2
		Group 26	0	2	0	2
		Group 32	7	18	2	27
		Group 33	0	1	0	1
Group 44		0	0	0	0	
Group 45		0	2	1	3	
Class Total		36	40	4	80	
Service Deferred	Group 16	3	3	0	6	
	Group 27	0	1	1	2	
	Group 35	1	2	2	5	
	Group 47	1	0	0	1	
	Class Total	5	6	3	14	
Grand Total			64,657	61,948	12,105	138,710

C3 Factor
Total Secondary Distribution Service Locations Factor

	Class	Rate Group	State			System
			MN	ND	SD	
A	Residential	Group 11	48,188	44,113	8,686	100,987
		Group 12	2,352	3,496	408	6,256
		Class Total	50,540	47,609	9,094	107,243
	Farms	Group 21	1,379	1,112	382	2,873
		Group 22	0	0	0	0
		Group 23	0	0	0	0
		Group 30	0	0	0	0
		Class Total	1,379	1,112	382	2,873
	General Service	Group 31	10,566	11,270	2,228	24,064
		Group 36	52	3	0	55
		Group 41	404	969	163	1,536
		Group 48	83	0	0	83
		Class Total	11,105	12,242	2,391	25,738
	Large General Service	Group 42	0	0	0	0
		Group 43	314	164	33	511
		Group 62	0	0	0	0
		Group 63	0	1	0	1
		Class Total	314	165	33	512
	Irrigation	Group 29	465	56	25	546
		Group 37	46	24	2	72
		Class Total	511	80	27	618
	Area & Street Lighting	Group 17	4	2	4	10
		Group 28	0	0	0	0
		Group 38	56	40	34	130
		Group 49	6	1	0	7
		Group 52	0	0	0	0
		Group 61	134	48	2	184
		Class Total	200	91	40	331
	OPA	Group 51	500	577	119	1,196
		Class Total	500	577	119	1,196
	Water Heating	Group 13	16	10	2	28
		Group 24	0	0	0	0
		Group 34	4	1	1	6
		Group 46	0	0	0	0
		Class Total	20	11	3	34
	Service Interrupt	Group 14	29	14	1	44
		Group 15	0	1	0	1
		Group 25	0	2	0	2
		Group 26	0	2	0	2
		Group 32	7	18	2	27
		Group 33	0	1	0	1
Group 44		0	0	0	0	
Group 45		0	2	1	3	
Class Total		36	40	4	80	
Service Deferred	Group 16	3	3	0	6	
	Group 27	0	1	1	2	
	Group 35	1	2	2	5	
	Group 47	1	0	0	1	
	Class Total	5	6	3	14	
Grand Total			64,610	61,933	12,096	138,639

Street and Area Light Factors (C4 & C5)

State	Account	
	Area Lights	Street Lights
	Book Cost	Book Cost
	C5	C4
MN	\$1,966,717.35	\$2,475,177.37
ND	\$2,477,820.18	\$2,381,279.34
SD	\$342,327.84	\$607,547.64
System	\$4,786,865.37	\$5,464,004.35

C6 Allocation Factor
Installed Cost of Meters in Service

Class		MN	ND	SD	System	mncost	ndcost	sdcost	systcost
Residential	RDC	2,361	3,491	411	6,263	\$1,213,554	\$1,794,374	\$211,254	\$3,219,182
	RES	47,836	43,859	8,661	100,356	\$5,644,648	\$5,175,362	\$1,021,998	\$11,842,008
	Total	50,197	47,350	9,072	106,619	6,858,202	6,969,736	1,233,252	15,061,190
Farms	FAR	1,378	1,105	389	2,872	\$679,354	\$544,765	\$191,777	\$1,415,896
	Total	1,378	1,105	389	2,872	679,354	544,765	191,777	1,415,896
General Service	CDC	.	.	.	.	.	.	.	.
	GSO	2,128	2,875	529	5,532	\$1,481,088	\$2,001,000	\$368,184	\$3,850,272
	GSU	8,669	9,179	1,850	19,698	\$6,033,624	\$6,388,584	\$1,287,600	\$13,709,808
	TUS	46	1	.	47	\$71,208	\$1,548	.	\$72,756
	Total	10,843	12,055	2,379	25,277	7,585,920	8,391,132	1,655,784	17,632,836
Large General Service	PLG	16	10	3	29	\$157,552	\$98,470	\$29,541	\$285,563
	SLG	514	267	70	851	\$883,566	\$458,973	\$120,330	\$1,462,869
	TLG	36	1	.	37	\$354,492	\$9,847	.	\$364,339
	Total	566	278	73	917	1,395,610	567,290	149,871	2,112,771
Irrigation	IRR	217	34	15	266	\$266,693	\$41,786	\$18,435	\$326,914
	Total	217	34	15	266	266,693	41,786	18,435	326,914
Outdoor Lighting	ALT	184	83	41	308	\$87,216	\$39,342	\$19,434	\$145,992
	Total	184	83	41	308	87,216	39,342	19,434	145,992
OPA	OPA	502	575	120	1,197	\$216,362	\$247,825	\$51,720	\$515,907
	Total	502	575	120	1,197	216,362	247,825	51,720	515,907
Cont Water Heating	WHR	8,248	5,979	2,166	16,393	\$3,381,680	\$2,451,390	\$888,060	\$6,721,130
	Total	8,248	5,979	2,166	16,393	3,381,680	2,451,390	888,060	6,721,130
Cont Serv Int	LDF	189	292	33	514	\$368,739	\$569,692	\$64,383	\$1,002,814
	SDF	6,441	7,430	1,008	14,879	\$2,685,897	\$3,098,310	\$420,336	\$6,204,543
	Total	6,630	7,722	1,041	15,393	3,054,636	3,668,002	484,719	7,207,357
Cont Serv Def	DFL	855	729	195	1,779	\$449,730	\$383,454	\$102,570	\$935,754
	FTD	529	377	97	1,003	\$278,254	\$198,302	\$51,022	\$527,578
	Total	1,384	1,106	292	2,782	727,984	581,756	153,592	1,463,332
Total		80,149	76,287	15,588	172,024	\$24,253,657	\$23,503,024	\$4,846,644	\$52,603,325

Residential = RDC+RES

Farms = FAR

General Service = GSO+GSU+TUS+CDC

Large General Service = PLG+SLG+TLG

Irrigation = IRR

Outdoor Lighting = ALT+SLT

OPA = OPA

Uncontrolled Water Heating = WHR

Controlled Service Interruptable = LDF+SDF

Controlled Service Deferred = DFL

FERC = FSD+FST+FWD+FWT

C7 Factor
Meter Reading Factor

Class	Rate Group	State			System
		MN	ND	SD	
A Residential	Group 11	48,571	43,527	8,672	100,770
	Group 12	2,381	3,496	407	6,284
	Class Total	50,952	47,023	9,079	107,054
Farms	Group 21	1,215	937	344	2,496
	Group 22	0	0	0	0
	Group 23	0	0	0	0
	Group 30	0	0	0	0
	Class Total	1,215	937	344	2,496
General Service	Group 31	23,781	18,435	4,302	46,518
	Group 36	112	3	0	115
	Group 41	679	1,511	302	2,493
	Group 48	154	0	0	154
	Class Total	24,725	19,950	4,604	49,279
Large General Service	Group 42	58	62	29	149
	Group 43	850	511	173	1,535
	Group 62	174	2	0	175
	Group 63	0	14	0	14
	Class Total	1,082	588	202	1,872
Irrigation	Group 29	205	23	13	241
	Group 37	118	25	2	145
	Class Total	323	48	15	387
Area & Street Lighting	Group 17	3	2	4	9
	Group 28	0	0	0	0
	Group 38	129	51	41	221
	Group 49	5	1	0	6
	Group 52	0	0	0	0
	Group 61	245	47	2	294
	Class Total	382	101	46	529
OPA	Group 51	772	738	233	1,743
	Class Total	772	738	233	1,743
Water Heating	Group 13	3,900	2,932	1,031	7,862
	Group 24	7	5	3	14
	Group 34	124	72	50	245
	Group 46	2	6	1	8
	Class Total	4,032	3,013	1,084	8,130
Service Interrupt	Group 14	2,334	2,982	392	5,709
	Group 15	0	5	0	5
	Group 25	48	56	12	117
	Group 26	2	7	0	9
	Group 32	488	677	85	1,250
	Group 33	67	91	9	166
	Group 44	18	37	2	57
	Group 45	74	124	17	214
	Class Total	3,031	3,978	517	7,526
Service Deferred	Group 16	371	248	75	694
	Group 27	10	8	2	21
	Group 35	222	258	55	535
	Group 47	43	40	6	88
	Class Total	646	553	138	1,337
Grand Total		87,159	76,928	16,264	180,351

C8 Factor
Total system Service Locations Factor

	Class	Rate Group	State			System
			MN	ND	SD	
A	Residential	Group 11	48,188	44,113	8,686	100,987
		Group 12	2,352	3,496	408	6,256
		Class Total	50,540	47,609	9,094	107,243
	Farms	Group 21	1,379	1,112	382	2,873
		Group 22	0	0	0	0
		Group 23	0	0	0	0
		Group 30	0	0	0	0
		Class Total	1,379	1,112	382	2,873
	General Service	Group 31	10,582	11,275	2,229	24,086
		Group 36	52	3	0	55
		Group 41	406	970	167	1,543
		Group 48	83	0	0	83
		Class Total	11,123	12,248	2,396	25,767
	Large General Service	Group 42	17	11	3	31
		Group 43	314	164	33	511
		Group 62	33	1	0	34
		Group 63	0	1	0	1
		Class Total	364	177	36	577
	Irrigation	Group 29	465	56	25	546
		Group 37	46	24	2	72
		Class Total	511	80	27	618
	Area & Street Lighting	Group 17	4	2	4	10
		Group 28	0	0	0	0
		Group 38	56	40	35	131
		Group 49	6	1	0	7
		Group 52	0	0	0	0
		Group 61	135	48	2	185
		Class Total	201	91	41	333
	OPA	Group 51	500	577	119	1,196
		Class Total	500	577	119	1,196
	Water Heating	Group 13	16	10	2	28
		Group 24	0	0	0	0
		Group 34	4	1	1	6
		Group 46	0	0	0	0
		Class Total	20	11	3	34
	Service Interrupt	Group 14	29	14	1	44
		Group 15	0	1	0	1
		Group 25	0	2	0	2
		Group 26	0	2	0	2
		Group 32	7	18	2	27
		Group 33	0	1	0	1
		Group 44	0	0	0	0
		Group 45	0	2	1	3
		Class Total	36	40	4	80
	Service Deferred	Group 16	3	3	0	6
		Group 27	0	1	1	2
		Group 35	1	2	2	5
		Group 47	1	0	0	1
		Class Total	5	6	3	14
Grand Total			64,679	61,951	12,105	138,735

C9 Factor
Load Management Factor

Class	Rate Group	State			System
		MN	ND	SD	
A Residential	Group 11	1,595	585	291	2,471
	Group 12	2,280	3,420	408	6,108
	Class Total	3,875	4,005	699	8,579
Farms	Group 21	39	5	15	59
	Group 22	0	0	0	0
	Group 23	0	0	0	0
	Group 30	0	0	0	0
	Class Total	39	5	15	59
General Service	Group 31	58	20	9	87
	Group 36	18	1	0	19
	Group 41	3	0	1	4
	Group 48	25	0	0	25
	Class Total	104	21	10	135
Large General Service	Group 42	0	0	0	0
	Group 43	0	1	1	2
	Group 62	0	0	0	0
	Group 63	0	0	0	0
	Class Total	0	1	1	2
Irrigation	Group 29	123	17	4	144
	Group 37	11	6	0	17
	Class Total	134	23	4	161
Area & Street Lighting	Group 17	0	0	0	0
	Group 28	0	0	0	0
	Group 38	0	0	0	0
	Group 49	0	0	0	0
	Group 52	0	0	0	0
	Group 61	0	0	0	0
	Class Total	0	0	0	0
OPA	Group 51	0	0	0	0
	Class Total	0	0	0	0
Water Heating	Group 13	7,991	5,839	2,068	15,898
	Group 24	42	17	8	67
	Group 34	215	135	71	421
	Group 46	3	9	1	13
	Class Total	8,251	6,000	2,148	16,399
Service Interrupt	Group 14	5,332	5,975	811	12,118
	Group 15	0	5	0	5
	Group 25	178	203	41	422
	Group 26	4	19	0	23
	Group 32	884	1,174	141	2,199
	Group 33	87	109	12	208
	Group 44	29	56	4	89
	Group 45	95	153	19	267
	Class Total	6,609	7,694	1,028	15,331
Service Deferred	Group 16	579	336	122	1,037
	Group 27	22	27	8	57
	Group 35	209	302	59	570
	Group 47	19	43	6	68
	Class Total	829	708	195	1,732
Grand Total		19,841	18,457	4,100	42,398

D1 - Generation Demand Factor
Class Summary Load Data

State	System Peak	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interruptable	Controlled Service Deferred	FERC	Class Total
FRC	15DEC16:09	0	0	0	0	0	0	0	0	0	0	975	975
MN	15DEC16:09	88,751	6,858	64,249	196,430	0	2,400	2,661	252	4,565	541	0	366,707
ND	15DEC16:09	94,960	6,921	82,461	86,514	0	2,816	2,782	183	7,354	740	0	284,731
SD	15DEC16:09	19,681	1,703	15,294	28,259	0	527	620	65	765	161	0	67,075
		203,392	15,482	162,004	311,203	0	5,743	6,063	500	12,684	1,442	975	719,488

Residential = RDC+RES

Farms = FAR

General Service = GSO+GSU+TUS

Large General Service = PLG+SLG+TLG

Irrigation = IRR

Outdoor Lighting = ALT+SLT

OPA = OPA

Uncontrolled Water Heating = WHR

Controlled Service Interruptable = LDF+SDF

Controlled Service Deferred = DFL

FERC = FSD+FST+FWD+FWT

***D2 - Transmission Demand Factor
Class Summary Load Data***

State	System Peak	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interruptable	Controlled Service Deferred	FERC	Class Total
FRC	15DEC16:09	0	0	0	0	0	0	0	0	0	0	5,951	5,951
MN	15DEC16:09	88,751	6,858	64,249	196,430	0	2,400	2,661	252	4,565	541	0	366,707
ND	15DEC16:09	94,960	6,921	82,461	86,514	0	2,816	2,782	183	7,354	740	0	284,731
SD	15DEC16:09	19,681	1,703	15,294	28,259	0	527	620	65	765	161	0	67,075
		203,392	15,482	162,004	311,203	0	5,743	6,063	500	12,684	1,442	5,951	724,464

Residential = RDC+RES

Farms = FAR

General Service = GSO+GSU+TUS

Large General Service = PLG+SLG+TLG

Irrigation = IRR

Outdoor Lighting = ALT+SLT

OPA = OPA

Uncontrolled Water Heating = WHR

Controlled Service Interruptable = LDF+SDF

Controlled Service Deferred = DFL

FERC = FSD+FST+FWD+FWT

***D3 - Distribution Primary Demand Factor
Class Summary Load Data***

State	Year	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interruptable	Controlled Service Deferred	FERC	Class Total
FRC	2016	0	0	0	0	0	0	0	0	0	0	5,177	5,177.0
MN	2016	74,223	10,821	76,522	120,400	6,046	4,827	2,792	9,449	49,087	6,132	0	360,299.0
ND	2016	89,167	12,217	85,800	102,198	753	5,637	2,710	6,845	79,147	8,512	0	392,986.0
SD	2016	17,638	2,423	16,182	31,229	398	1,114	602	2,427	8,691	2,436	0	83,140.0
		181,028	25,461	178,504	253,827	7,197	11,578	6,104	18,721	136,925	17,080	5,177	841,602

Residential = RDC+RES

Farms = FAR

General Service = GSO+GSU+TUS

Large General Service = PLG+SLG+TLG

Irrigation = IRR

Outdoor Lighting = ALT+SLT

OPA = OPA

Uncontrolled Water Heating = WHR

Controlled Service Interruptable = LDF+SDF

Controlled Service Deferred = DFL

FERC = FSD+FST+FWD+FWT

***D4 - Distribution Secondary Demand Factor
Class Summary Load Data***

State	Year	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interruptable	Controlled Service Deferred	FERC	Class Total
FRC	2016	0	0	0	0	0	0	0	0	0	0	0	0
MN	2016	98,080	16,802	112,540	91,798	9,539	4,566	4,476	28,522	76,702	10,630	0	453,655
ND	2016	138,886	19,021	127,398	79,799	1,292	5,332	5,499	21,366	121,338	13,969	0	533,900
SD	2016	29,359	3,493	21,791	30,924	623	1,054	779	7,526	12,806	3,785	0	112,140
		266,325	39,316	261,729	202,521	11,454	10,952	10,754	57,414	210,846	28,384	0	1,099,695

Residential = RDC+RES

Farms = FAR

General Service = GSO+GSU+TUS

Large General Service = PLG+SLG+TLG

Irrigation = IRR

Outdoor Lighting = ALT+SLT

OPA = OPA

Uncontrolled Water Heating = WHR

Controlled Service Interruptable = LDF+SDF

Controlled Service Deferred = DFL

FERC = FSD+FST+FWD+FWT

E1 Factor
Energy Factor

Class	Rate Group	State				System
		MN	ND	SD	FERC	
A Residential	Group 11	429,147	425,689	95,229	0	950,065
	Group 12	22,090	36,404	3,901	0	62,395
	Class Total	451,237	462,093	99,130	0	1,012,460
Farms	Group 21	39,974	31,442	8,336	0	79,752
	Group 22	0	0	0	0	0
	Group 23	0	0	0	0	0
	Group 30	0	0	0	0	0
	Class Total	39,974	31,442	8,336	0	79,752
General Service	Group 31	243,876	221,966	43,261	0	509,103
	Group 36	1,343	50	0	0	1,393
	Group 41	73,800	196,193	34,997	0	304,990
	Group 48	16,086	0	0	0	16,086
	Class Total	335,105	418,209	78,258	0	831,572
Large General Service	Group 42	144,860	180,460	4,511	0	329,831
	Group 43	508,133	409,159	224,696	0	1,141,988
	Group 62	979,908	21,446	0	0	1,001,354
	Group 63	0	57,994	0	0	57,994
	Class Total	1,632,901	669,059	229,207	0	2,531,167
Irrigation	Group 29	0	0	0	0	0
	Group 37	0	0	0	0	0
	Class Total	0	0	0	0	0
Area & Street Lighting	Group 17	2,068	1,791	438	0	4,297
	Group 28	422	383	98	0	903
	Group 38	5,174	6,006	955	0	12,135
	Group 49	2,176	2,471	391	0	5,038
	Group 52	0	0	0	0	0
	Group 61	10,836	13,940	2,852	0	27,628
	Class Total	20,676	24,591	4,734	0	50,001
OPA	Group 51	20,523	18,161	4,251	0	42,935
	Class Total	20,523	18,161	4,251	0	42,935
Water Heating	Group 13	8,420	6,228	2,151	0	16,799
	Group 24	47	18	8	0	73
	Group 34	452	179	163	0	794
	Group 46	5	18	0	0	23
	Class Total	8,924	6,443	2,322	0	17,689
Service Interrupt	Group 14	0	0	0	0	0
	Group 15	0	0	0	0	0
	Group 25	0	0	0	0	0
	Group 26	0	0	0	0	0
	Group 32	0	0	0	0	0
	Group 33	0	0	0	0	0
	Group 44	0	0	0	0	0
	Group 45	0	0	0	0	0
	Class Total	0	0	0	0	0
Service Deferred	Group 16	3,920	2,953	904	0	7,777
	Group 27	647	477	84	0	1,208
	Group 35	4,522	5,512	1,012	0	11,046
	Group 47	2,178	3,458	800	0	6,436
	Class Total	11,267	12,400	2,800	0	26,467
Wholesale	Group 80	0	0	0	3,408	3,408
	Class Total	0	0	0	3,408	3,408
Grand Total		2,520,607	1,642,398	429,038	3,408	4,595,451

E2 Factor
Energy Factor

Class	Rate Group	State				System
		MN	ND	SD	FERC	
A Residential	Group 11	429,147	425,689	95,229	0	950,065
	Group 12	53,017	87,369	9,363	0	149,749
	Class Total	482,164	513,058	104,592	0	1,099,814
Farms	Group 21	39,974	31,442	8,336	0	79,752
	Group 22	0	0	0	0	0
	Group 23	0	0	0	0	0
	Group 30	0	0	0	0	0
	Class Total	39,974	31,442	8,336	0	79,752
General Service	Group 31	243,876	221,966	43,261	0	509,103
	Group 36	3,223	120	0	0	3,343
	Group 41	73,800	196,193	34,997	0	304,990
	Group 48	38,605	0	0	0	38,605
	Class Total	359,504	418,279	78,258	0	856,041
Large General Service	Group 42	144,860	180,460	4,511	0	329,831
	Group 43	508,133	409,159	224,696	0	1,141,988
	Group 62	979,908	21,446	0	0	1,001,354
	Group 63	0	57,994	0	0	57,994
	Class Total	1,632,901	669,059	229,207	0	2,531,167
Irrigation	Group 29	4,644	537	311	0	5,492
	Group 37	418	278	9	0	705
	Class Total	5,062	815	320	0	6,197
Area & Street Lighting	Group 17	2,068	1,791	438	0	4,297
	Group 28	422	383	98	0	903
	Group 38	5,174	6,006	955	0	12,135
	Group 49	2,176	2,471	391	0	5,038
	Group 52	0	0	0	0	0
	Group 61	10,836	13,940	2,852	0	27,628
	Class Total	20,676	24,591	4,734	0	50,001
OPA	Group 51	20,523	18,161	4,251	0	42,935
	Class Total	20,523	18,161	4,251	0	42,935
Water Heating	Group 13	20,208	14,947	5,162	0	40,317
	Group 24	114	43	19	0	176
	Group 34	1,086	431	391	0	1,908
	Group 46	12	44	1	0	57
	Class Total	21,420	15,465	5,573	0	42,458
Service Interrupt	Group 14	65,109	99,408	10,443	0	174,960
	Group 15	50	348	0	0	398
	Group 25	2,827	4,254	551	0	7,632
	Group 26	106	2,449	0	0	2,555
	Group 32	15,376	27,326	2,653	0	45,355
	Group 33	5,686	10,386	416	0	16,488
	Group 44	1,343	3,771	1,339	0	6,453
	Group 45	31,632	55,065	5,749	0	92,446
	Class Total	122,129	203,007	21,151	0	346,287
Service Deferred	Group 16	9,408	7,087	2,170	0	18,665
	Group 27	1,554	1,145	201	0	2,900
	Group 35	10,852	13,230	2,428	0	26,510
	Group 47	5,227	8,299	1,921	0	15,447
	Class Total	27,041	29,761	6,720	0	63,522
Wholesale	Group 80	0	0	0	3,408	3,408
	Class Total	0	0	0	3,408	3,408
Grand Total		2,731,394	1,923,638	463,142	3,408	5,121,582

PSC-04.31

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Gina Ice, Rate Analyst

Data Request:

Please provide the minimum system study and the associated allocators that were used in the Company's CCOSS to allocate its electric distribution plant. Please provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formula intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Attachments: 1

Attachment 1 to DR ND-PSC-04.31.xlsx

Response:

Please see Attachment 1 to DR ND-PSC-04.31 for the minimum size study performed by OTP to allocate its electric distribution plant.

PSC-04.31, ATTACHMENT 1

Minimum System Study

References:

- National Association of Regulatory Utility Commissioners (NARUC)
- OTPCo's Cost Allocation Procedure Manual for Jurisdictional and Class Cost of Service Studies
- Handy-Whitman Index of Public Utility Construction Costs
- National Electric Safety Code (NESC)

Color Index for Cell Fill

Where or what is this?
Engineering data entry
Calculation in the sheet
Display from other sheet in workbook
Display from this sheet in workbook
Accounting area entry
GIS data entry
Input to another sheet

Abbreviations

XFMR	Transformer
NARUC	National Association of Regulatory Utility Commissioners
NESC	National Electric Safety Code
SME	Subject Matter Expert
pdmt	Padmount

Color index for Text Color

Original data/label	black
Notes for the cell, line	Purple
changed/updated data	red
changed/updated data accepted into workbook	blue

Comment

Minimum System Study Workbook Inputs

Year Study Data is pulled from

2015

End of the year from which the study data is pulled from.

Engineering (Construction Data) inputs

Comment

364 Information

Minimum size pole

35C5

Minimum system layout design, Standards and WOE

Number of poles in length of primary

30

Minimum system layout design, Standards and WOE

365 Information

Primary Distribution Circuit miles

5280

Minimum system layout design, Standards and WOE

Primary Minimum Size primary Unit

1/0R

Minimum system layout design, Standards and WOE

Average number of poles in minimum size primary unit of primary conductor

30

Minimum system layout design, Standards and WOE

Secondary Minimum Size primary Unit

3000

Minimum system layout design, Standards and WOE - amount of secondary wire used in sample unit

367 Information

Primary Minimum size primary unit

10J15

the company, Minimum standard Primary UG conductor

Primary Number of feet of conductor in the minimum size primary unit.

5280

WOE, 1-mile sample, length of primary needed for the model

Secondary Minimum Size secondary Unit

10TX6

Minimum Secondary UG conductor needed for the model

Secondary Number of feet of secondary conductor in minimum size unit

4,899

calculation of adjusted average cost of primary for sample

Lighting Percent of total number of lighting units (street and area lights) that is streetlights

90.00%

Need to confirm percentage of street lights vs area lights

369 Information

Number of services in Work order

96

369.1 Information

Minimum size of a service. (100' #2TX)

2TX

Number of services in Work order

96

Accounting (Asset Data) inputs

RETAIL CUSTOMERS

MN

ND

SD

TOTAL

Residential - Urban	42060	44733	8183	94976
Residential - Rural	4598	645	395	5638
Cottages	1955	1	201	2157
Farms	1444	999	370	2813

Current year of the OTTER TAIL POWER
COMPANY RETAIL CUSTOMERS, KWH &
ELECTRIC REVENUE

Average Years of Accounts

Year of Depreciation Study: 2015
Book Date of Depreciation Study: 12/31/2013

FERC Account	FERC Description	Physical Average age of plant
364	Poles, Towers & Fixtures	41
365	Overhead Conductor & Devices	39
366	Underground Conduit	21
367	Underground Conductor & Devices	21
368	Line Transformers polemount	32
368	Line Transformers pdmt	13

364 Accounting Tab ->Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 364 Pole Vintage Count & Cost

365 Accounting Tab ->Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 365 Conductor & Insulator Vintage Count & Cost

Account no longer used

367 Accounting Tab->Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 367 underground Conductor Vintage Count & Cost

368 Polemount Accounting Tab ->Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 368 Pole Mount Transformer Vintage Count & Cost

368 Padmount Accounting Tab ->Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 368 Pole Mount Transformer Vintage Count & Cost

369	Services (Overhead)	46
369.1	Underground Services	23

369 Accounting Tab ->Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 369 Overhead Services Vintage Count & Cost
369.1 Polemount Accounting Tab ->Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 369 Underground Services Vintage Count & Cost

364 Information

Number of streetlights in the system	30,878
Number of area lights in the system	18,876

Qty from account 373, PP - Asset 1115 Report; This is the number of Street Lights in the System
Qty from account 371.2, PP - Asset 1115 Report; This is the number of Area Lights in the System

FERC Account	Type	Quantity	Book Cost
364	C-TRUSS	5	2093.81
364	EASEMENT	422	202321.78
364	Non Unitized	55	152236.58
364	POLE	168009	57464965.61
364	XARM	187936.48	10091111.33

Qty & \$ from account 364, C-Truss, PP - Asset 1115 Report
Qty & \$ from account 364, Easements, PP - Asset 1115 Report
Qty & \$ from account 364, Non-Unitized, PP - Asset 1115 Report
Qty & \$ from account 364, Pole, PP - Asset 1115 Report
Qty & \$ from account 364, Xarm, PP - Asset 1115 Report

365 Information

FERC Account	Type	Quantity	Book Cost
365	ARRESTERS	538	\$105,557.53
365	AUTO BOOSTER	0	\$0.00
365	CAPACITOR BANK	0	\$0.00
365	CIRCUIT SWITCH	0	\$0.00
365	CIRCUIT SWITCHER	0	\$0.00
365	COND ACSR	8,787,649	\$16,098,803.32
365	COND ALL ALUM	896,217	\$2,467,076.00
365	COND ALUM WP	1,736,007	\$2,403,454.14
365	COND COPPER BARE	833,528	\$512,268.45
365	COND COPPER BARE 3 STR	0	\$0.00
365	COND COPPER WP	2,163,441	\$819,365.02

Qty & \$ from account 365, PP - Asset 1115 Report
Not applicable
Not applicable
Not applicable
Not applicable
Qty & \$ from account 365, PP - Asset 1115 Report
Qty & \$ from account 365, PP - Asset 1115 Report
Qty & \$ from account 365, PP - Asset 1115 Report
Qty & \$ from account 365, PP - Asset 1115 Report

Not applicable
Qty & \$ from account 365, PP - Asset 1115 Report

365	COND COPPERWELD	0	\$0.00
365	COND DUPLEX	3,285,588	\$3,158,491.31
365	COND DUPLEX 600 V	3753	\$3,692.51
365	COND IRON	331,456	\$61,091.38
365	COND QUADRUPLX	430,811	\$1,468,486.71
365	COND TRIPLEX	3,883,708	\$7,601,298.82
365	CUTOUTS	2,626	\$522,116.43
365	FAULT INDICATOR	42	\$20,364.26
365	INSULATED GUY STRAIN	10	\$1,316.52
	INSULATOR		
365	INSULATOR	401,835	\$10,941,458.60
365	INTERRUPT SWITCH	0	\$0.00
365	MOTOR OPERAT SW	0	\$0.00
365	MOTOR OPERATOR	13	\$37,077.27
365	NON UNITIZED	53	\$240,525.25
365	OIL SWITCH	0	\$0.00
365	POLE TOP SWITCH	0	\$0.00
365	RECLOSER	73	\$316,147.68
365	RECLOSERS	0	\$0.00
365	SECTIONALIZERS	15	\$144,069.08
365	SWITCH OPERATOR	0	\$0.00
365	SWITCHES POLE TOP	481	\$1,278,877.06

Not applicable
Qty & \$ from account 365, PP - Asset 1115 Report
Qty & \$ from account 365, PP - Asset 1115 Report
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Qty & \$ from account 365, PP - Asset 1115 Report
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Qty & \$ from account 365, PP - Asset 1115 Report
Not applicable
Qty & \$ from account 365, PP - Asset 1115 Report

367 Information

FERC Account	Type	Quantity	Book Cost
367	ARRESTERS	16,605	\$2,517,746.10
367	COND ALL ALUM	13,620	\$69,861.16
367	COND ALUM	15,122,659	\$50,447,964.97
367		0	\$0.00
367		0	\$0.00
	COND ALUM 600 V 1 COND	1,009,544	\$2,104,184.26
367			
367	COND COPPER BARE	3,594	\$3,314.07
367	COND DUPLEX	665	\$331.64
367	COND DUPLEX 600 V	1,715,436	\$2,491,386.07
	COND QUADRUPLX 600 V	6350	\$25,605.18
367			
367	COND TRIPLEX	3685	\$10,024.92
367	COND TRIPLEX 15 KV	2,706	\$16,309.08
367	COND TRIPLEX 600 V	2,370,665	\$5,741,589.51
367	CUTOUTS	14,411	\$2,492,273.20

Qty & \$ from account 367, PP - Asset 1115 Report
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Qty & \$ from account 367, PP - Asset 1115 Report

367	EASEMENT	149	\$9,012.35
367	ENCLOSURE	390	\$524,165.53
367	FAULT INDICATOR	849	\$235,002.94
367	NON UNITIZED	59	\$1,388,562.71
367	RECLOSERS	3	\$116,597.36
367	SPEC. EQUIPMENT	0	\$0.00
367	SPECIAL EQUIP	0	\$0.00
367	SWITCHES LOAD BREAK	88	\$978,545.65

Qty & \$ from account 367, PP - Asset 1115 Report

Qty & \$ from account 367, PP - Asset 1115 Report

Qty & \$ from account 367, PP - Asset 1115 Report

Qty & \$ from account 367, PP - Asset 1115 Report

Qty & \$ from account 367, PP - Asset 1115 Report

Not applicable

Not applicable

Qty & \$ from account 367, PP - Asset 1115 Report

368 Information

FERC			
Account	Type	Quantity	Book Cost
368	ARRESTER-CUTOUT	0	\$0.00
368	ARRESTERS	39,421	\$2,986,955.52
368	AUTO 0-10	0	\$0.00
368	AUTO 11-100	0	\$0.00
368	AUTOBOOSTER	3	\$4,205.49
368	CAPACITOR	875	\$923,494.94
368	CAPACITOR CONTROL	0	\$0.00
368	CAPACITOR BANK	4	\$414.44
368	CUTOUTS	41,419	\$3,795,363.99
368	LINE PROTECTOR	0	\$0.00
368	NON UNITIZED	65	\$1,244,115.14
368	OIL SWITCHES	0	\$0.00
368	PADMT 101-500 1PH	220	\$822,720.01
368	PADMT 101-500 3PH	1,673	\$16,809,188.62
368	PADMT 11-100 1PH	8,285	\$15,078,180.52
368	PADMT 11-100 3PH	2328	\$2,797,350.94
368	PADMT 1501+ 3PH	78	\$2,800,839.95
368	PADMT 501-1500 3PH	248	\$5,641,366.63
368	POLEMT 0-10 1PH	6,640	\$3,636,769.52
368	POLEMT 101-500 1PH	250	\$464,301.23
368	POLEMT 101-500 3PH	0	\$0.00
368	POLEMT 11-100 1PH	27,509	\$28,006,431.69
368	POLEMT 11-100 3PH	2	\$6,237.20
368	POLEMT 1501+ 3PH	0	\$0.00
368	POLEMT 501-1500 1PH	0	\$0.00
368	POLEMT 501-1500 3PH	0	\$0.00
368	POTENTIAL TRANS	0	\$0.00
368	RECLOSER	0	\$0.00
368	REGULATOR	34	\$233,433.65
368	SELF-REG 1-100	0	\$0.00
368	STATION TRANSFORMER	89	\$114,926.97

Not applicable

Qty & \$ from account 368, PP - Asset 1115 Report

Not applicable

Not applicable

Qty & \$ from account 368, PP - Asset 1115 Report

Qty & \$ from account 368, PP - Asset 1115 Report

Not applicable

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Qty & \$ from account 368, PP - Asset 1115 Report

Not applicable

Not applicable

Not applicable

Not applicable

Qty & \$ from account 368, PP - Asset 1115 Report

Not applicable

Qty & \$ from account 368, PP - Asset 1115 Report

368	TRANSFORMER	0	\$0.00
368	TRANSFORMER AUTO	0	\$0.00

Not applicable

Not applicable

369 Information

FERC			
Account	Type	Quantity	Book Cost
369	SERVICE 2 WIRE	24,537	\$467,606.77
369	SERVICE 3 WIRE	59,257	\$10,685,956.55
369	SERVICE 4 WIRE	5,942	\$1,477,127.72

Qty & \$ from account 369, PP - Asset 1115 Report

Qty & \$ from account 369, PP - Asset 1115 Report

Qty & \$ from account 369, PP - Asset 1115 Report

369.1 Information

FERC			
Account	Type	Quantity	Book Cost
369.1	EASEMENT	1	\$20.00
369.1	SERVICE 3 WIRE	52,732	\$32,605,532.18
369.1	SERVICE 4 WIRE	3,885	\$5,374,135.03

Qty & \$ from account 36910, PP - Asset 1115 Report

Qty & \$ from account 36910, PP - Asset 1115 Report

Qty & \$ from account 36910, PP - Asset 1115 Report

Handy-Whitman Index factor - Total Plant - Year end:		2015	
FERC			
Account	Total Distribution Plant (average for year of review)		673
364	Poles, Towers & Fixtures	1974	100
365	Overhead Conductor & Devices	1976	143
366	Underground Conduit	N/A	N/A
367	Underground Conductor & Devices	1994	278
368	Line Transformers polemount	1983	207
368	Line Transformers padmount	2002	339
369	Services (Overhead)	1969	65
369.1	Underground Services	1992	218

Underground							
Trenching cost Primary	\$2.96	per foot	average cost by contractor to install primary cable plow/trench	4	2.4	3	2.45
Trenching cost Secondary	\$2.16	per foot	average cost by contractor to install primary cable plow/trench	3.1	1.75	2	1.8
Trenching cost Service	\$2.48	per foot	average cost by contractor to install primary cable plow/trench	3.1	3	2	1.8

Results of Minimum System Study									
Account		Total \$ in account	DSL	DAL	DPCC	DPDC	DSCC	DSDC	Total
364	Distribution Pole	\$67,912,729	\$3,371,398	\$1,648,773	\$19,438,461	\$43,454,097			\$67,912,729
365	Distribution Conductor	\$47,939,331	\$2,123,629	\$1,038,555	\$6,260,573	\$22,702,984	\$2,930,343	\$12,883,247	\$47,939,331
366	Underground Conduit	\$0							\$0
367	U. G. Conductor	\$69,172,477	\$2,242,546	\$249,172	\$45,004,581	\$13,794,775	\$4,235,809	\$3,645,594	\$69,172,477
368	Transformers	\$85,366,296					\$30,848,676	\$54,517,621	\$85,366,296
369	Overhead services	\$12,630,691					\$4,128,225	\$8,502,466	\$12,630,691
369.1	Underground Services	\$37,979,687					\$25,130,479	\$12,849,208	\$37,979,687
		\$321,001,212	\$7,737,573	\$2,936,499	\$70,703,614	\$79,951,856	\$67,273,533	\$92,398,136	

\$321,001,212 \$321,001,212

2015 Results in Format for Functionalization Percentages										
Account			PRIMARY DEMAND	SECONDARY DEMAND	PRIMARY CUSTOMER	SECONDARY CUSTOMER	STREET LIGHTS	AREA LIGHTS	Totals	
364	Distribution Pole	\$67,912,729	\$43,454,097	\$0	\$19,438,461	\$0	\$3,371,398	\$1,648,773	\$67,912,729	100.00%
365	Distribution Conductor	\$47,939,331	\$22,702,984	\$12,883,247	\$6,260,573	\$2,930,343	\$2,123,629	\$1,038,555	\$47,939,331	100.00%
366	U.G. Conduit	\$0							\$0	0.00%
367	U. G. Conductor	\$69,172,477	\$13,794,775	\$3,645,594	\$45,004,581	\$4,235,809	\$2,242,546	\$249,172	\$69,172,477	100.00%
368	Transformers	\$85,366,296	\$0	\$54,517,621	\$0	\$30,848,676	\$0	\$0	\$85,366,296	100.00%
369	Overhead services	\$12,630,691	\$0	\$8,502,466	\$0	\$4,128,225	\$0	\$0	\$12,630,691	100.00%
369.1	Underground Services	\$37,979,687	\$0	\$12,849,208	\$0	\$25,130,479	\$0	\$0	\$37,979,687	100.00%
	Totals	\$321,001,212	\$79,951,856	\$92,398,136	\$70,703,614	\$67,273,533	\$7,737,573	\$2,936,499		

		% of Total
Total Demand	\$172,349,992	53.69%
Total Customer	\$137,977,147	42.98%
Lighting	\$10,674,073	3.33%

[illegible]

2005 Functionalization Percentages (Previous Minimum System Study)								
		PRIMARY DEMAND	SECONDARY DEMAND	PRIMARY CUSTOMER	SECONDARY CUSTOMER	STREET LIGHTS	AREA LIGHTS	Totals
364	Distribution Pole	52.34%	0.00%	41.56%	0.00%	5.52%	0.58%	100.00%
365	Distribution Conductor	39.31%	28.19%	18.52%	6.61%	6.67%	0.70%	100.00%
366	Underground Conduit	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
367	U. G. Conductor	23.79%	1.07%	56.53%	13.77%	4.35%	0.48%	100.00%
368	Transformers	0.00%	50.64%	0.00%	49.36%	0.00%	0.00%	100.00%
369	Overhead services	0.00%	32.51%	0.00%	67.49%	0.00%	0.00%	100.00%
369.1	Underground Services	0.00%	36.31%	0.00%	63.69%	0.00%	0.00%	100.00%

2005 Study (2003 Data)		% of Total
Total Demand	\$93,133,401	46%
Total Customer	\$99,627,138	50%

Raw Change New Minimum System Study from Previous Study								
		PRIMARY DEMAND	SECONDARY DEMAND	PRIMARY CUSTOMER	SECONDARY CUSTOMER	STREET LIGHTS	AREA LIGHTS	
364	Distribution Pole	11.65%	0.00%	-12.93%	0.00%	-0.56%	1.85%	
365	Distribution Conductor	8.05%	-1.32%	-5.46%	-0.50%	-2.24%	1.46%	
366	Underground Conduit	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
367	U. G. Conductor	-3.85%	4.20%	8.53%	-7.64%	-1.11%	-0.12%	
368	Transformers	0.00%	13.22%	0.00%	-13.22%	0.00%	0.00%	
369	Overhead services	0.00%	34.81%	0.00%	-34.81%	0.00%	0.00%	
369.1	Underground Services	0.00%	-2.47%	0.00%	2.47%	0.00%	0.00%	

	Change in points
Total Demand Change in %	7.25%
Total Customer Change in %	-6.69%

Positive number indicates that 2014 is higher than 2003

Residential - Urban	94,976
Residential - Rural	5,638
Cottages	2,157
Farms	2,813
Total	105,584

- PSL = Poles for Streetlights
- DSL = Dollars allocated to Streetlighting
- DAL = Dollars allocated to Area Lighting
- DPCC = Dollars allocated to Primary Customer Category
- DPDC = Dollars allocated to Primary Demand Category
- DSCC = Dollars allocated to Secondary Customer Category
- DSDC = Dollars allocated to Secondary Demand Category
- UPD = Units of Primary Distribution
- USD = Units of Secondary Distribution

System setup for a 1-mile unit test/sample

City Block	400 feet	8 (lots/cust) per Block	blocks/ mile:	12
Street	45 feet	11 streets/ 12 blocks	Customers in 1-mile	96
NARUC - Customer demand	0.83 kW/Cust	3 Transformers (XFMR) KVA needed:	79.68 KVA	

Layout - Refer to associated layout design in AutoCAD

Riser -> ~800' run cable -> XFMR -> ~1600' run cable -> XFMR -> ~1600' run Cable -> Use 5280 for system
Pedestals: ~200' appart - allow the average service to remain at 165', blocks only allow for 6 connections in each pedestal
xfmrs and ped connections blocks will receive 6 connections each, each ped can serve five customers need 24 peds, 24/4=6; 6 peds must be served by each XFMR
between xfmrs and peds, we need 24 to serve 96 customers.
cost to install secondary with primary \$0.50/ft

WOE - CRs for reference	working CRs (Construction Request in work order estimate system)	62705	62706	62707

Estimate	62705	Primary and secondary										
	CONST CODE	INSTALL	REMOVE	O & M	HOT	DESCRIPTION	ACCT	DIRECT LABOR	MATL	DIRECT MAT	OTHER COS	TOTAL
poi1	1024	1				RISER 1P W/TERM W/100AMP CO 15	36700	7,809.90	18,909.81	0	29,757.58	56,477.29
	UC10J15	5280				CABLE UG 15KV AL 1/0 JACKETED	36800	1,354.74	4,362.46	0	1,772.32	7,489.52
	232B25	2				TRANS 25 KVA 1PPMT 12.47GRDY/7						63,966.81
	232B25	1				TRANS 25 KVA 1PPMT 12.47GRDY/7						
poi2	UC10TX6	4609				CABLE SECONDARY 10TX 600 VOLT						
	1306	20				PEDESTAL ENCLOSURE SECONDARY						
oth	UG CONTRACTOR 4484'@\$3/FT	13452		OTH	36700							
	EASEMENTS 1/2 DIS 4609, .75/FT	3457		OTH	36700							
	INSTALL SECONDARY 4609*\$0.5/FT	2305		OTH	36700							

Estimate	62706	services										
CONST CODE		INSTALL	REMOVE	O & M	HOT	DESCRIPTION	ACCT	DIRECT LABOR	MATL	DIRECT MAT	OTHER COS	TOTAL
poi2	UC10TX6	165				CABLE SECONDARY 10TX 600 VOLT	36700	540.21	151.8	0	658.68	1,350.69
	DN1422051	3				H-TAP STOCK NO. 1422051	36901	0	15.44	0	4.16	19.60
	DLTAP	3				LABOR TAP 1 COMPRESS FITTING W	I'm not able to estimate a service, the total from these will be a service. This is a 1-s					
	ULHDPS	2				LABOR HAND DIG PIT SMALL 2' X	36901	51860.16	16055.04	0	63632.64	131,547.84
	ULMCE	1				LABOR MARK CABLE AND EQ.	MULT:	96				
	SU1547254	2				U-GUARD 2" X 10' STRAIGHT P/FG						

Combined system - summation of Primary, Secondary and Services

ACCT	DIRECT LABOR	MATL	DIRECT MAT	OTHER COS	TOTAL
36700	7,809.90	18,909.81	0.00	29,757.58	56,477.29
36800	1,354.74	4,362.46	0.00	1,772.32	7,489.52
36901	51860.16	16055.04	0	63632.64	131,547.84
					195,514.65

Estimate	62707	secondary										
	CONST CODE	INSTALL	REMOVE	O & M	HOT	DESCRIPTION	ACCT	DIRECT LABOR	MATL	DIRECT MAT	OTHER COS	TOTAL
poi2 UC10TX6		4899				CABLE SECONDARY 10TX 600 VOLT	36700	4,520.21	7,098.84	0	6,868.96	18,488.01
	1306	24				PEDESTAL ENCLOSURE SECONDARY						

working CRs (Construction Request in work order estimate system)	62705	62706	62707
System setup for a 1-mile unit test/sample			
City Block	400 feet	lots/cust per Block:	8
Street	45 feet	streets/ 12 blocks:	11
NARUC - Customer	0.83 kW/Cust	Transformers (XFMR) KVA needed:	79.7 KVA
		blocks/ mile:	12
		Customers in 1-mile:	96

Layout - Refer to associated layout design in AutoCAD

Construction with 35 foot class five poles spaced approximately 180' apart. Poles are located to allow service connection to each lot with minimal encroachment onto the neighbors yard.

Eight transformers are spaced along the line. Each transformer will serve 12 customers

WOE - CRs for reference	Estimates created:	62702	62703	62704

Travel to job and lunch 10 miles

Estimate	62702 distribution primary				1-mile sample							
	CONST CODE	INSTALL	REMOVE	O & M	HOT	DESCRIPTION	ACCT	DIRECT LABOR	MATL	DIRECT MATL	OTHER COST	TOTAL
poi2	DP355	30				POLE WOOD 35 FT CLASS 5	36400	10,205.32	8,160.92	0	11,026.22	29,392.46
	2305	28				SINGLE PHASE, 1PW&N,PIN POLE T	36800	2,538.80	5,600.17	0	2,984.44	11,123.41
	2566	2				DEAD-END VERTICAL 1PW+N ZAG	36500	4,455.44	4,391.62	0	3,769.80	12,616.86
	5028	4				GUY DOWN 3/8" W/GRIP, REFLECTO						53,132.73
	DC10R	5280				CONDUCTOR 1/0 ACSR 6/1 RAVEN						
	DC10R	5280				CONDUCTOR 1/0 ACSR 6/1 RAVEN						
poi3	DSDER3S	22				SECONDARY DEAD-END RACK 3 SPOO						
	DSDER3S	8				SECONDARY DEAD-END RACK 3 SPOO						
	DC2TX	3000				CONDUCTOR 2 TRIPLEX COCKLE						
poi4	205A10	8				XFORMER 7200/12470Y-120/240 10						
oth	EASEMENT 1/2 DIS	2904	OTH		36400							

Estimate	62073 distribution service				1 service sample							
CONST CODE	INSTALL	REMOVE	O & M	HOT	DESCRIPTION	ACCT	DIRECT LABOR	MATL	DIRECT MATL	OTHER COST	TOTAL	
DC2TX	100				CONDUCTOR 2 TRIPLEX COCKLE	36500	299.68	58.30	-	223.34	581.32	
DN1422051	6				H-TAP STOCK NO. 1422051	THIS IS A SAMPLE - ACCOUNT IS REALLY 369 AND WE NEED 96 services						
DCWS	2				CLAMP WEDGE, SMALL 2 THRU 6 AC	36900	28,769.28	5,596.80	-	21,440.64	55,806.72	
DLEQUIPC	1				1 HR LABOR OPERATE EQUIP CONDU	MULT:	96					
crew to do work, travel 10 miles												

Combined system - summation of Primary, Secondary and Services

ACCT	DIRECT LABOR	MATL	DIRECT MATL	OTHER COST	TOTAL
36400	10,205.32	8,160.92	0	11,026.22	29,392.46
36800	2,538.80	5,600.17	0	2,984.44	11,123.41
36500	4,455.44	4,391.62	0	3,769.80	12,616.86
36900	28,769.28	5,596.80	0.00	21,440.64	55,806.72
					108,939.45

Estimate 62704 distribution secondary 1-mile sample											
CONST CODE	INSTALL	REMOVE	O & M	HOT	DESCRIPTION	ACCT	DIRECT LABOR	MATL	DIRECT MATL	OTHER COST	TOTAL
DSDER3S	22				SECONDARY DEAD-END RACK 3 SPOO	36400	1,039.53	810.9	0	828.36	2,678.79
DSDER3S	15				SECONDARY DEAD-END RACK 3 SPOO	36500	746.73	1,680.00	0	891.43	3,318.16
DC2TX	4080				CONDUCTOR 2 TRIPLEX COCKLE	due to how this is being WOE, I can not contain only secondary, we will have to sum this two to get the					
						36500	1,786.26	2,490.90	0.00	1,719.79	5,996.95

due to how this is being WOE, I can not contain only secondary, we will have to sum this two to get the OH secondary

[illegible]

Year Study Performed

2015

O.H. Work Order Data from the Overhead Line Framing tab

	ACCT	DIRECT LABOR	MATL	DIRECT MATL	OTHER COST	TOTAL COST	Avg Install Cost
Poles	36400	10,205.32	8,160.92	0.00	11,026.22	29,392.46	
transformer	36800	2,538.80	5,600.17	0.00	2,984.44	11,123.41	1,390.43
conductor	36500	4,455.44	4,391.62	0.00	3,769.80	12,616.86	
services	36900	28,769.28	5,596.80	0.00	21,440.64	55,806.72	
						108,939.45	

Secondary O.H. work order

	ACCT	DIRECT LABOR	MATL	DIRECT MATL	OTHER COST	TOTAL
	36400					
	36800					
	36500	1,786.26	2,490.90	0.00	1,719.79	5,996.95
	36900					

Primary O.H. Components

numbers were generated by taking the difference between the two above

36400						
36800						
36500	2,669.18	1,900.72	0.00	2,050.01	6,619.91	12,616.86
36900						

UG Work Order CR

	ACCT	DIRECT LABOR	MATL	DIRECT MATL	OTHER COST	TOTAL COST	
	36700	7,809.90	18,909.81	0.00	29,757.58	56,477.29	14119.32
	36800	1,354.74	4,362.46	0.00	1,772.32	7,489.52	2496.51
	36901	51,860.16	16,055.04	0.00	63,632.64	131,547.84	
						195,514.65	

Secondary UG Work Order

CR

	ACCT	DIRECT LABOR	MATL	DIRECT MATL	OTHER COST	TOTAL COST
	36700	4,520.21	7,098.84	0.00	6,868.96	18,488.01
	36901	51,860.16	16,055.04	0.00	63,632.64	131,547.84
						150,035.85

Primary UG Components

ACCT	DIRECT LABOR	MATL	DIRECT MATL	OTHER COST	TOTAL COST
36800					
36700	3,289.69	11,810.97		22,888.62	37,989.28
369.1					

Utility Account	Retire ment Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36400 - Poles, Towers and Fixtures	Pole	1929	961	\$17,732.86	\$18.45	961	\$ 17,732.86	18.45
36400 - Poles, Towers and Fixtures	Pole	1930	899	\$17,926.51	\$19.94	1,860	35,659.37	19.17
36400 - Poles, Towers and Fixtures	Pole	1931	1,584	\$51,577.91	\$32.56	3,444	87,237.28	25.33
36400 - Poles, Towers and Fixtures	Pole	1932	612	\$10,701.57	\$17.49	4,056	97,938.85	24.15
36400 - Poles, Towers and Fixtures	Pole	1933	74	\$1,293.90	\$17.49	4,130	99,232.75	24.03
36400 - Poles, Towers and Fixtures	Pole	1934	278	\$5,162.22	\$18.57	4,408	104,394.97	23.68
36400 - Poles, Towers and Fixtures	Pole	1935	427	\$7,968.40	\$18.66	4,835	112,363.37	23.24
36400 - Poles, Towers and Fixtures	Pole	1936	740	\$15,953.99	\$21.56	5,575	128,317.36	23.02
36400 - Poles, Towers and Fixtures	Pole	1937	1,320	\$25,672.59	\$19.45	6,895	153,989.95	22.33
36400 - Poles, Towers and Fixtures	Pole	1938	554	\$11,588.70	\$20.92	7,449	165,578.65	22.23
36400 - Poles, Towers and Fixtures	Pole	1939	364	\$7,285.28	\$20.01	7,813	172,863.93	22.13
36400 - Poles, Towers and Fixtures	Pole	1940	110	\$2,392.49	\$21.75	7,923	175,256.42	22.12
36400 - Poles, Towers and Fixtures	Pole	1941	1,171	\$27,748.24	\$23.70	9,094	203,004.66	22.32
36400 - Poles, Towers and Fixtures	Pole	1942	553	\$12,353.15	\$22.34	9,647	215,357.81	22.32
36400 - Poles, Towers and Fixtures	Pole	1943	208	\$5,099.11	\$24.51	9,855	220,456.92	22.37
36400 - Poles, Towers and Fixtures	Pole	1944	265	\$7,206.67	\$27.19	10,120	227,663.59	22.50
36400 - Poles, Towers and Fixtures	Pole	1945	380	\$10,428.92	\$27.44	10,500	238,092.51	22.68
36400 - Poles, Towers and Fixtures	Pole	1946	361	\$10,507.50	\$29.11	10,861	248,600.01	22.89
36400 - Poles, Towers and Fixtures	Pole	1947	534	\$18,996.40	\$35.57	11,395	267,596.41	23.48
36400 - Poles, Towers and Fixtures	Pole	1948	1,395	\$50,715.92	\$36.36	12,790	318,312.33	24.89
36400 - Poles, Towers and Fixtures	Pole	1949	3,297	\$123,671.96	\$37.51	16,087	441,984.29	27.47
36400 - Poles, Towers and Fixtures	Pole	1950	1,597	\$60,633.79	\$37.97	17,684	502,618.08	28.42
36400 - Poles, Towers and Fixtures	Pole	1951	1,955	\$120,517.59	\$61.65	19,639	623,135.67	31.73
36400 - Poles, Towers and Fixtures	Pole	1952	1,907	\$99,268.99	\$52.06	21,546	722,404.66	33.53
36400 - Poles, Towers and Fixtures	Pole	1953	3,200	\$164,972.62	\$51.55	24,746	887,377.28	35.86
36400 - Poles, Towers and Fixtures	Pole	1954	2,093	\$106,341.39	\$50.81	26,839	993,718.67	37.03
36400 - Poles, Towers and Fixtures	Pole	1955	2,291	\$167,471.19	\$73.10	29,130	1,161,189.86	39.86
36400 - Poles, Towers and Fixtures	Pole	1956	2,413	\$188,479.77	\$78.11	31,543	1,349,669.63	42.79
36400 - Poles, Towers and Fixtures	Pole	1957	2,632	\$212,927.20	\$80.90	34,175	1,562,596.83	45.72
36400 - Poles, Towers and Fixtures	Pole	1958	2,617	\$229,620.43	\$87.74	36,792	1,792,217.26	48.71
36400 - Poles, Towers and Fixtures	Pole	1959	2,566	\$267,349.99	\$104.19	39,358	2,059,567.25	52.33

Utility Account	Retire ment Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36400 - Poles, Towers and Fixtures	Pole	1960	3,115	\$351,353.00	\$112.79	42,473	2,410,920.25	56.76
36400 - Poles, Towers and Fixtures	Pole	1961	2,641	\$275,845.00	\$104.45	45,114	2,686,765.25	59.56
36400 - Poles, Towers and Fixtures	Pole	1962	2,825	\$327,364.91	\$115.88	47,939	3,014,130.16	62.87
36400 - Poles, Towers and Fixtures	Pole	1963	2,826	\$322,613.04	\$114.16	50,765	3,336,743.20	65.73
36400 - Poles, Towers and Fixtures	Pole	1964	3,188	\$351,789.26	\$110.35	53,953	3,688,532.46	68.37
36400 - Poles, Towers and Fixtures	Pole	1965	3,228	\$354,544.59	\$109.83	57,181	4,043,077.05	70.71
36400 - Poles, Towers and Fixtures	Pole	1966	3,389	\$379,696.60	\$112.04	60,570	4,422,773.65	73.02
36400 - Poles, Towers and Fixtures	Pole	1967	3,276	\$373,658.92	\$114.06	63,846	4,796,432.57	75.13
36400 - Poles, Towers and Fixtures	Pole	1968	3,171	\$375,982.86	\$118.57	67,017	5,172,415.43	77.18
36400 - Poles, Towers and Fixtures	Pole	1969	3,609	\$469,217.33	\$130.01	70,626	5,641,632.76	79.88
36400 - Poles, Towers and Fixtures	Pole	1970	3,025	\$454,514.13	\$150.25	73,651	6,096,146.89	82.77
36400 - Poles, Towers and Fixtures	Pole	1971	3,348	\$526,782.37	\$157.34	76,999	6,622,929.26	86.01
36400 - Poles, Towers and Fixtures	Pole	1972	2,929	\$457,043.09	\$156.04	79,928	7,079,972.35	88.58
36400 - Poles, Towers and Fixtures	Pole	1973	2,734	\$494,509.47	\$180.87	82,662	7,574,481.82	91.63
36400 - Poles, Towers and Fixtures	Pole	1974	2,781	\$392,288.75	\$141.06	85,443	7,966,770.57	93.24
36400 - Poles, Towers and Fixtures	Pole	1975	2,326	\$519,132.50	\$223.19	87,769	8,485,903.07	96.68
36400 - Poles, Towers and Fixtures	Pole	1976	2,946	\$688,084.52	\$233.57	90,715	9,173,987.59	101.13
36400 - Poles, Towers and Fixtures	Pole	1977	3,253	\$845,621.78	\$259.95	93,968	10,019,609.37	106.63
36400 - Poles, Towers and Fixtures	Pole	1978	2,390	\$659,123.20	\$275.78	96,358	10,678,732.57	110.82
36400 - Poles, Towers and Fixtures	Pole	1979	2,404	\$805,145.88	\$334.92	98,762	11,483,878.45	116.28
36400 - Poles, Towers and Fixtures	Pole	1980	2,498	\$860,755.79	\$344.58	101,260	12,344,634.24	121.91
36400 - Poles, Towers and Fixtures	Pole	1981	2,588	\$976,188.40	\$377.20	103,848	13,320,822.64	128.27
36400 - Poles, Towers and Fixtures	Pole	1982	2,828	\$1,294,045.29	\$457.58	106,676	14,614,867.93	137.00
36400 - Poles, Towers and Fixtures	Pole	1983	2,377	\$947,750.88	\$398.72	109,053	15,562,618.81	142.71
36400 - Poles, Towers and Fixtures	Pole	1984	2,295	\$906,412.82	\$394.95	111,348	16,469,031.63	147.91
36400 - Poles, Towers and Fixtures	Pole	1985	2,868	\$1,212,560.42	\$422.79	114,216	17,681,592.05	154.81
36400 - Poles, Towers and Fixtures	Pole	1986	2,261	\$1,083,231.93	\$479.09	116,477	18,764,823.98	161.10
36400 - Poles, Towers and Fixtures	Pole	1987	3,139	\$1,299,214.19	\$413.89	119,616	20,064,038.17	167.74
36400 - Poles, Towers and Fixtures	Pole	1988	2,616	\$1,394,456.57	\$533.05	122,232	21,458,494.74	175.56
36400 - Poles, Towers and Fixtures	Pole	1989	2,149	\$1,059,733.60	\$493.13	124,381	22,518,228.34	181.04
36400 - Poles, Towers and Fixtures	Pole	1990	2,356	\$1,031,867.69	\$437.97	126,737	23,550,096.03	185.82

Utility Account	Retire ment Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36400 - Poles, Towers and Fixtures	Pole	1991	2,669	\$1,104,659.39	\$413.89	129,406	24,654,755.42	190.52
36400 - Poles, Towers and Fixtures	Pole	1992	2,408	\$1,069,095.76	\$443.98	131,814	25,723,851.18	195.15
36400 - Poles, Towers and Fixtures	Pole	1993	2,524	\$1,310,188.53	\$519.09	134,338	27,034,039.71	201.24
36400 - Poles, Towers and Fixtures	Pole	1994	2,030	\$1,121,907.59	\$552.66	136,368	28,155,947.30	206.47
36400 - Poles, Towers and Fixtures	Pole	1995	2,374	\$1,343,164.71	\$565.78	138,742	29,499,112.01	212.62
36400 - Poles, Towers and Fixtures	Pole	1996	1,810	\$1,104,458.76	\$610.20	140,552	30,603,570.77	217.74
36400 - Poles, Towers and Fixtures	Pole	1997	1,776	\$1,034,706.74	\$582.61	142,328	31,638,277.51	222.29
36400 - Poles, Towers and Fixtures	Pole	1998	1,822	\$969,831.10	\$532.29	144,150	32,608,108.61	226.21
36400 - Poles, Towers and Fixtures	Pole	1999	2,306	\$1,228,101.98	\$532.57	146,456	33,836,210.59	231.03
36400 - Poles, Towers and Fixtures	Pole	2000	2,257	\$1,158,347.42	\$513.22	148,713	34,994,558.01	235.32
36400 - Poles, Towers and Fixtures	Pole	2001	1,557	\$981,246.47	\$630.22	150,270	35,975,804.48	239.41
36400 - Poles, Towers and Fixtures	Pole	2002	2,060	\$1,508,308.41	\$732.19	152,330	37,484,112.89	246.07
36400 - Poles, Towers and Fixtures	Pole	2003	1,133	\$1,256,060.26	\$1,108.61	153,463	38,740,173.15	252.44
36400 - Poles, Towers and Fixtures	Pole	2004	1,475	\$1,628,687.92	\$1,104.20	154,938	40,368,861.07	260.55
36400 - Poles, Towers and Fixtures	Pole	2005	1,455	\$1,893,512.95	\$1,301.38	156,393	42,262,374.02	270.23
36400 - Poles, Towers and Fixtures	Pole	2006	1,212	\$1,725,097.73	\$1,423.35	157,605	43,987,471.75	279.10
36400 - Poles, Towers and Fixtures	Pole	2007	1,353	\$2,071,248.15	\$1,530.86	158,958	46,058,719.90	289.75
36400 - Poles, Towers and Fixtures	Pole	2008	1,143	\$1,345,429.56	\$1,177.10	160,101	47,404,149.46	296.09
36400 - Poles, Towers and Fixtures	Pole	2009	1,015	\$1,404,502.37	\$1,383.75	161,116	48,808,651.83	302.94
36400 - Poles, Towers and Fixtures	Pole	2010	1,652	\$1,898,674.00	\$1,149.32	162,768	50,707,325.83	311.53
36400 - Poles, Towers and Fixtures	Pole	2011	1,400	\$1,828,482.58	\$1,306.06	164,168	52,535,808.41	320.01
36400 - Poles, Towers and Fixtures	Pole	2012	1,424	\$2,312,073.92	\$1,623.65	165,592	54,847,882.33	331.22
36400 - Poles, Towers and Fixtures	Pole	2013	1,142	\$1,560,585.72	\$1,366.54	166,734	56,408,468.05	338.31
36400 - Poles, Towers and Fixtures	Pole	2014	1,010	\$1,337,258.37	\$1,324.02	167,744	57,745,726.42	344.25
36400 - Poles, Towers and Fixtures	Pole	2015	156	\$195,037.78	\$1,250.24	167,900	57,940,764.20	345.09
			167,900	\$ 57,940,764.20	\$ 345.09			

mid point

83,950

\$ 28,970,382.10

\$ 172.55

41	Average Physical Age of Poles
20	Weighted Cost Average Age of poles

Utility Account	Retire	Vint	Vintage	Vintage Cost	Average	Accum	Accum Cost	Accum
	ment	age	Quantity		Cost	Quantity		Average
	Unit							Cost
		27	Age of Average Cost of Poles					

Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 364 Pole Vintage Count & Cost

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond All Alum	1921	346	\$44.00	\$0.13	346	\$ 44.00	\$ 0.13
36500 - Overhead Conductors, Device	Cond All Alum	1922	112	\$12.46	\$0.11	458	56.46	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1923	528	\$61.78	\$0.12	986	118.24	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1924	8,981	\$1,024.88	\$0.11	9,967	1,143.12	\$ 0.11
36500 - Overhead Conductors, Device	Cond All Alum	1924	1,191	\$139.81	\$0.12	11,158	1,282.93	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Wp	1925	14,883	\$1,786.62	\$0.12	26,041	3,069.55	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1925	1,192	\$140.51	\$0.12	27,233	3,210.06	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1925	27	\$2.83	\$0.10	27,260	3,212.89	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1926	31,522	\$3,596.79	\$0.11	58,782	6,809.68	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1926	2,988	\$326.19	\$0.11	61,770	7,135.87	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1926	880	\$88.68	\$0.10	62,650	7,224.55	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1927	84,758	\$9,671.04	\$0.11	147,408	16,895.59	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Bare	1927	3,612	\$352.68	\$0.10	151,020	17,248.27	\$ 0.11
36500 - Overhead Conductors, Device	Cond All Alum	1927	2,663	\$269.44	\$0.10	153,683	17,517.71	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Wp	1928	107,519	\$12,906.87	\$0.12	261,202	30,424.58	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1928	9,760	\$778.37	\$0.08	270,962	31,202.95	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1928	5,212	\$555.31	\$0.11	276,174	31,758.26	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Wp	1929	78,104	\$10,316.53	\$0.13	354,278	42,074.79	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1929	10,292	\$860.68	\$0.08	364,570	42,935.47	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1929	3,965	\$442.69	\$0.11	368,535	43,378.16	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1930	78,234	\$8,926.55	\$0.11	446,769	52,304.71	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1930	6,685	\$518.64	\$0.08	453,454	52,823.35	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1930	2,597	\$240.10	\$0.09	456,051	53,063.45	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1931	85,782	\$8,754.59	\$0.10	541,833	61,818.04	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Bare	1931	12,627	\$837.62	\$0.07	554,460	62,655.66	\$ 0.11
36500 - Overhead Conductors, Device	Cond All Alum	1931	4,836	\$416.12	\$0.09	559,296	63,071.78	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Wp	1932	35,944	\$3,451.75	\$0.10	595,240	66,523.53	\$ 0.11
36500 - Overhead Conductors, Device	Insulator	1932	748	\$1,985.98	\$2.66	595,988	68,509.51	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Bare	1932	2,867	\$187.46	\$0.07	598,855	68,696.97	\$ 0.11
36500 - Overhead Conductors, Device	Cond All Alum	1932	608	\$46.36	\$0.08	599,463	68,743.33	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Wp	1933	11,250	\$1,080.13	\$0.10	610,713	69,823.46	\$ 0.11

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Insulator	1933	40	\$105.52	\$2.64	610,753	69,928.98	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Bare	1933	449	\$35.21	\$0.08	611,202	69,964.19	\$ 0.11
36500 - Overhead Conductors, Device	Cond All Alum	1933	139	\$10.90	\$0.08	611,341	69,975.09	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Wp	1934	20,483	\$2,213.62	\$0.11	631,824	72,188.71	\$ 0.11
36500 - Overhead Conductors, Device	Insulator	1934	135	\$398.22	\$2.95	631,959	72,586.93	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Bare	1934	1,227	\$90.21	\$0.07	633,186	72,677.14	\$ 0.11
36500 - Overhead Conductors, Device	Cond All Alum	1934	96	\$8.07	\$0.08	633,282	72,685.21	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Wp	1935	27,506	\$2,972.72	\$0.11	660,788	75,657.93	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Bare	1935	1,164	\$92.60	\$0.08	661,952	75,750.53	\$ 0.11
36500 - Overhead Conductors, Device	Insulator	1935	23	\$67.49	\$2.93	661,975	75,818.02	\$ 0.11
36500 - Overhead Conductors, Device	Cond All Alum	1935	171	\$14.01	\$0.08	662,146	75,832.03	\$ 0.11
36500 - Overhead Conductors, Device	Cond Copper Wp	1936	44,526	\$5,080.55	\$0.11	706,672	80,912.58	\$ 0.11
36500 - Overhead Conductors, Device	Insulator	1936	484	\$1,488.30	\$3.08	707,156	82,400.88	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1936	3,591	\$280.78	\$0.08	710,747	82,681.66	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1936	1,455	\$116.46	\$0.08	712,202	82,798.12	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1937	69,251	\$8,313.08	\$0.12	781,453	91,111.20	\$ 0.12
36500 - Overhead Conductors, Device	Insulator	1937	1,512	\$4,862.74	\$3.22	782,965	95,973.94	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1937	7,754	\$598.83	\$0.08	790,719	96,572.77	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1937	2,204	\$187.93	\$0.09	792,923	96,760.70	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1938	65,113	\$7,429.50	\$0.11	858,036	104,190.20	\$ 0.12
36500 - Overhead Conductors, Device	Insulator	1938	318	\$965.51	\$3.04	858,354	105,155.71	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1938	7,786	\$583.66	\$0.07	866,140	105,739.37	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1938	1,272	\$102.23	\$0.08	867,412	105,841.60	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1939	45,943	\$5,242.26	\$0.11	913,355	111,083.86	\$ 0.12
36500 - Overhead Conductors, Device	Insulator	1939	287	\$865.89	\$3.02	913,642	111,949.75	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1939	7,202	\$523.25	\$0.07	920,844	112,473.00	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1939	1,790	\$141.28	\$0.08	922,634	112,614.28	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1940	17,047	\$1,945.35	\$0.11	939,681	114,559.63	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1940	1,201	\$107.41	\$0.09	940,882	114,667.04	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1940	273	\$21.19	\$0.08	941,155	114,688.23	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1941	56,494	\$6,446.18	\$0.11	997,649	121,134.41	\$ 0.12

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Insulator	1941	357	\$1,063.87	\$2.98	998,006	122,198.28	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1941	8,975	\$688.44	\$0.08	1,006,981	122,886.72	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1941	2,141	\$170.22	\$0.08	1,009,122	123,056.94	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1942	16,361	\$2,062.37	\$0.13	1,025,483	125,119.31	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1942	5,285	\$416.21	\$0.08	1,030,768	125,535.52	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1942	1,100	\$89.64	\$0.08	1,031,868	125,625.16	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1943	336	\$25.23	\$0.08	1,032,204	125,650.39	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1943	76	\$9.59	\$0.13	1,032,280	125,659.98	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1943	93	\$7.52	\$0.08	1,032,373	125,667.50	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1944	14,650	\$1,846.62	\$0.13	1,047,023	127,514.12	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1944	4,115	\$327.53	\$0.08	1,051,138	127,841.65	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1944	576	\$45.69	\$0.08	1,051,714	127,887.34	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1945	47,280	\$6,245.26	\$0.13	1,098,994	134,132.60	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1945	9,254	\$803.04	\$0.09	1,108,248	134,935.64	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1945	1,028	\$83.43	\$0.08	1,109,276	135,019.07	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1946	44,307	\$6,649.33	\$0.15	1,153,583	141,668.40	\$ 0.12
36500 - Overhead Conductors, Device	Insulator	1946	350	\$1,329.78	\$3.80	1,153,933	142,998.18	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Bare	1946	9,038	\$901.76	\$0.10	1,162,971	143,899.94	\$ 0.12
36500 - Overhead Conductors, Device	Cond All Alum	1946	1,405	\$133.47	\$0.09	1,164,376	144,033.41	\$ 0.12
36500 - Overhead Conductors, Device	Cond Copper Wp	1947	42,887	\$7,465.96	\$0.17	1,207,263	151,499.37	\$ 0.13
36500 - Overhead Conductors, Device	Insulator	1947	593	\$2,596.70	\$4.38	1,207,856	154,096.07	\$ 0.13
36500 - Overhead Conductors, Device	Cond Copper Bare	1947	4,414	\$546.57	\$0.12	1,212,270	154,642.64	\$ 0.13
36500 - Overhead Conductors, Device	Cond All Alum	1947	318	\$34.54	\$0.11	1,212,588	154,677.18	\$ 0.13
36500 - Overhead Conductors, Device	Cond Copper Wp	1948	132,277	\$24,620.27	\$0.19	1,344,865	179,297.45	\$ 0.13
36500 - Overhead Conductors, Device	Insulator	1948	2,231	\$10,378.01	\$4.65	1,347,096	189,675.46	\$ 0.14
36500 - Overhead Conductors, Device	Cond Copper Bare	1948	26,093	\$3,246.12	\$0.12	1,373,189	192,921.58	\$ 0.14
36500 - Overhead Conductors, Device	Cond All Alum	1948	1,103	\$127.95	\$0.12	1,374,292	193,049.53	\$ 0.14
36500 - Overhead Conductors, Device	Cond Copper Wp	1949	201,489	\$37,502.47	\$0.19	1,575,781	230,552.00	\$ 0.15
36500 - Overhead Conductors, Device	Insulator	1949	6,339	\$29,298.30	\$4.62	1,582,120	259,850.30	\$ 0.16
36500 - Overhead Conductors, Device	Cond Copper Bare	1949	42,460	\$5,198.64	\$0.12	1,624,580	265,048.94	\$ 0.16
36500 - Overhead Conductors, Device	Cond All Alum	1949	1,695	\$194.55	\$0.11	1,626,275	265,243.49	\$ 0.16

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Copper Wp	1950	93,711	\$19,413.64	\$0.21	1,719,986	284,657.13	\$ 0.17
36500 - Overhead Conductors, Device	Cond Copper Bare	1950	20,031	\$3,061.08	\$0.15	1,740,017	287,718.21	\$ 0.17
36500 - Overhead Conductors, Device	Insulator	1950	294	\$1,178.10	\$4.01	1,740,311	288,896.31	\$ 0.17
36500 - Overhead Conductors, Device	Cond All Alum	1950	795	\$621.79	\$0.78	1,741,106	289,518.10	\$ 0.17
36500 - Overhead Conductors, Device	Cond Copper Wp	1951	77,738	\$38,757.25	\$0.50	1,818,844	328,275.35	\$ 0.18
36500 - Overhead Conductors, Device	Insulator	1951	2,519	\$10,660.14	\$4.23	1,821,363	338,935.49	\$ 0.19
36500 - Overhead Conductors, Device	Cond Copper Bare	1951	19,651	\$8,036.39	\$0.41	1,841,014	346,971.88	\$ 0.19
36500 - Overhead Conductors, Device	Cond Copper Wp	1952	61,173	\$38,296.12	\$0.63	1,902,187	385,268.00	\$ 0.20
36500 - Overhead Conductors, Device	Insulator	1952	2,672	\$11,707.58	\$4.38	1,904,859	396,975.58	\$ 0.21
36500 - Overhead Conductors, Device	Cond Copper Bare	1952	35,908	\$8,427.17	\$0.23	1,940,767	405,402.75	\$ 0.21
36500 - Overhead Conductors, Device	Cond Acsr	1952	485	\$58.92	\$0.12	1,941,252	405,461.67	\$ 0.21
36500 - Overhead Conductors, Device	Cond Copper Wp	1953	180,998	\$86,027.93	\$0.48	2,122,250	491,489.60	\$ 0.23
36500 - Overhead Conductors, Device	Insulator	1953	4,930	\$22,904.10	\$4.65	2,127,180	514,393.70	\$ 0.24
36500 - Overhead Conductors, Device	Cond Copper Bare	1953	24,072	\$5,005.71	\$0.21	2,151,252	519,399.41	\$ 0.24
36500 - Overhead Conductors, Device	Cond Copper Wp	1954	39,394	\$25,250.39	\$0.64	2,190,646	544,649.80	\$ 0.25
36500 - Overhead Conductors, Device	Insulator	1954	2,495	\$11,749.11	\$4.71	2,193,141	556,398.91	\$ 0.25
36500 - Overhead Conductors, Device	Cond Copper Bare	1954	22,704	\$3,164.06	\$0.14	2,215,845	559,562.97	\$ 0.25
36500 - Overhead Conductors, Device	Cond Acsr	1954	15,048	\$1,304.95	\$0.09	2,230,893	560,867.92	\$ 0.25
36500 - Overhead Conductors, Device	Cond Iron	1954	5,120	\$317.90	\$0.06	2,236,013	561,185.82	\$ 0.25
36500 - Overhead Conductors, Device	Cond Copper Wp	1955	37,288	\$41,364.65	\$1.11	2,273,301	602,550.47	\$ 0.27
36500 - Overhead Conductors, Device	Insulator	1955	3,809	\$19,500.64	\$5.12	2,277,110	622,051.11	\$ 0.27
36500 - Overhead Conductors, Device	Cond Acsr	1955	48,135	\$18,456.64	\$0.38	2,325,245	640,507.75	\$ 0.28
36500 - Overhead Conductors, Device	Cond Copper Bare	1955	16,513	\$5,003.06	\$0.30	2,341,758	645,510.81	\$ 0.28
36500 - Overhead Conductors, Device	Cond Iron	1955	20,025	\$1,964.57	\$0.10	2,361,783	647,475.38	\$ 0.27
36500 - Overhead Conductors, Device	Cond Copper Wp	1956	24,554	\$41,443.08	\$1.69	2,386,337	688,918.46	\$ 0.29
36500 - Overhead Conductors, Device	Cond Acsr	1956	193,845	\$35,617.64	\$0.18	2,580,182	724,536.10	\$ 0.28
36500 - Overhead Conductors, Device	Insulator	1956	3,789	\$21,196.91	\$5.59	2,583,971	745,733.01	\$ 0.29
36500 - Overhead Conductors, Device	Cond Alum Wp	1956	44,014	\$15,492.81	\$0.35	2,627,985	761,225.82	\$ 0.29
36500 - Overhead Conductors, Device	Cond Iron	1956	24,538	\$2,362.19	\$0.10	2,652,523	763,588.01	\$ 0.29
36500 - Overhead Conductors, Device	Cond Copper Bare	1956	5,816	\$1,069.22	\$0.18	2,658,339	764,657.23	\$ 0.29
36500 - Overhead Conductors, Device	Cond Acsr	1957	180,189	\$63,746.56	\$0.35	2,838,528	828,403.79	\$ 0.29

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Copper Wp	1957	41,692	\$39,174.73	\$0.94	2,880,220	867,578.52	\$ 0.30
36500 - Overhead Conductors, Device	Insulator	1957	4,369	\$23,980.34	\$5.49	2,884,589	891,558.86	\$ 0.31
36500 - Overhead Conductors, Device	Cond Alum Wp	1957	49,874	\$17,839.11	\$0.36	2,934,463	909,397.97	\$ 0.31
36500 - Overhead Conductors, Device	Cond Iron	1957	17,679	\$2,736.03	\$0.15	2,952,142	912,134.00	\$ 0.31
36500 - Overhead Conductors, Device	Cond Copper Bare	1957	4,905	\$1,102.74	\$0.22	2,957,047	913,236.74	\$ 0.31
36500 - Overhead Conductors, Device	Cond Acsr	1958	178,099	\$70,919.26	\$0.40	3,135,146	984,156.00	\$ 0.31
36500 - Overhead Conductors, Device	Cond Copper Wp	1958	33,704	\$32,414.44	\$0.96	3,168,850	1,016,570.44	\$ 0.32
36500 - Overhead Conductors, Device	Insulator	1958	4,171	\$25,538.10	\$6.12	3,173,021	1,042,108.54	\$ 0.33
36500 - Overhead Conductors, Device	Cond Alum Wp	1958	47,814	\$21,911.78	\$0.46	3,220,835	1,064,020.32	\$ 0.33
36500 - Overhead Conductors, Device	Cond Copper Bare	1958	25,040	\$10,016.65	\$0.40	3,245,875	1,074,036.97	\$ 0.33
36500 - Overhead Conductors, Device	Cond Iron	1958	27,497	\$3,217.86	\$0.12	3,273,372	1,077,254.83	\$ 0.33
36500 - Overhead Conductors, Device	Cond Acsr	1959	134,073	\$56,415.97	\$0.42	3,407,445	1,133,670.80	\$ 0.33
36500 - Overhead Conductors, Device	Cond Copper Wp	1959	30,160	\$45,731.92	\$1.52	3,437,605	1,179,402.72	\$ 0.34
36500 - Overhead Conductors, Device	Insulator	1959	5,052	\$33,043.76	\$6.54	3,442,657	1,212,446.48	\$ 0.35
36500 - Overhead Conductors, Device	Cond Alum Wp	1959	68,285	\$32,140.35	\$0.47	3,510,942	1,244,586.83	\$ 0.35
36500 - Overhead Conductors, Device	Cond Copper Bare	1959	61,828	\$14,848.99	\$0.24	3,572,770	1,259,435.82	\$ 0.35
36500 - Overhead Conductors, Device	Cond Iron	1959	43,930	\$9,230.23	\$0.21	3,616,700	1,268,666.05	\$ 0.35
36500 - Overhead Conductors, Device	Cond Acsr	1960	236,380	\$95,511.69	\$0.40	3,853,080	1,364,177.74	\$ 0.35
36500 - Overhead Conductors, Device	Cond Copper Wp	1960	52,696	\$57,492.41	\$1.09	3,905,776	1,421,670.15	\$ 0.36
36500 - Overhead Conductors, Device	Cond Alum Wp	1960	72,635	\$39,586.52	\$0.55	3,978,411	1,461,256.67	\$ 0.37
36500 - Overhead Conductors, Device	Insulator	1960	4,468	\$27,982.07	\$6.26	3,982,879	1,489,238.74	\$ 0.37
36500 - Overhead Conductors, Device	Cond Copper Bare	1960	56,917	\$16,900.99	\$0.30	4,039,796	1,506,139.73	\$ 0.37
36500 - Overhead Conductors, Device	Cond All Alum	1960	26,261	\$9,456.56	\$0.36	4,066,057	1,515,596.29	\$ 0.37
36500 - Overhead Conductors, Device	Cond Iron	1960	28,819	\$9,425.93	\$0.33	4,094,876	1,525,022.22	\$ 0.37
36500 - Overhead Conductors, Device	Cond Acsr	1961	196,537	\$87,058.18	\$0.44	4,291,413	1,612,080.40	\$ 0.38
36500 - Overhead Conductors, Device	Cond Copper Wp	1961	29,214	\$42,036.81	\$1.44	4,320,627	1,654,117.21	\$ 0.38
36500 - Overhead Conductors, Device	Insulator	1961	4,863	\$28,967.79	\$5.96	4,325,490	1,683,085.00	\$ 0.39
36500 - Overhead Conductors, Device	Cond Alum Wp	1961	51,594	\$26,453.57	\$0.51	4,377,084	1,709,538.57	\$ 0.39
36500 - Overhead Conductors, Device	Cond Copper Bare	1961	36,510	\$9,427.14	\$0.26	4,413,594	1,718,965.71	\$ 0.39
36500 - Overhead Conductors, Device	Cond Iron	1961	29,077	\$7,132.83	\$0.25	4,442,671	1,726,098.54	\$ 0.39
36500 - Overhead Conductors, Device	Cond All Alum	1961	7,947	\$4,138.60	\$0.52	4,450,618	1,730,237.14	\$ 0.39

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Acsr	1962	229,193	\$117,398.69	\$0.51	4,679,811	1,847,635.83	\$ 0.39
36500 - Overhead Conductors, Device	Cond Copper Wp	1962	21,141	\$46,102.52	\$2.18	4,700,952	1,893,738.35	\$ 0.40
36500 - Overhead Conductors, Device	Insulator	1962	5,666	\$42,051.15	\$7.42	4,706,618	1,935,789.50	\$ 0.41
36500 - Overhead Conductors, Device	Cond Alum Wp	1962	49,613	\$30,922.75	\$0.62	4,756,231	1,966,712.25	\$ 0.41
36500 - Overhead Conductors, Device	Cond Iron	1962	30,152	\$11,798.20	\$0.39	4,786,383	1,978,510.45	\$ 0.41
36500 - Overhead Conductors, Device	Cond Copper Bare	1962	38,179	\$10,440.67	\$0.27	4,824,562	1,988,951.12	\$ 0.41
36500 - Overhead Conductors, Device	Cond All Alum	1962	17,225	\$6,900.43	\$0.40	4,841,787	1,995,851.55	\$ 0.41
36500 - Overhead Conductors, Device	Cond Acsr	1963	197,158	\$115,380.22	\$0.59	5,038,945	2,111,231.77	\$ 0.42
36500 - Overhead Conductors, Device	Cond Alum Wp	1963	50,606	\$42,194.14	\$0.83	5,089,551	2,153,425.91	\$ 0.42
36500 - Overhead Conductors, Device	Insulator	1963	5,592	\$35,384.51	\$6.33	5,095,143	2,188,810.42	\$ 0.43
36500 - Overhead Conductors, Device	Cond Copper Wp	1963	19,614	\$29,870.66	\$1.52	5,114,757	2,218,681.08	\$ 0.43
36500 - Overhead Conductors, Device	Cond All Alum	1963	24,833	\$14,047.01	\$0.57	5,139,590	2,232,728.09	\$ 0.43
36500 - Overhead Conductors, Device	Cond Copper Bare	1963	29,673	\$8,331.43	\$0.28	5,169,263	2,241,059.52	\$ 0.43
36500 - Overhead Conductors, Device	Cond Iron	1963	37,341	\$1,469.79	\$0.04	5,206,604	2,242,529.31	\$ 0.43
36500 - Overhead Conductors, Device	Cond Acsr	1964	301,235	\$196,829.43	\$0.65	5,507,839	2,439,358.74	\$ 0.44
36500 - Overhead Conductors, Device	Cond Alum Wp	1964	70,159	\$74,255.06	\$1.06	5,577,998	2,513,613.80	\$ 0.45
36500 - Overhead Conductors, Device	Insulator	1964	6,243	\$40,971.77	\$6.56	5,584,241	2,554,585.57	\$ 0.46
36500 - Overhead Conductors, Device	Cond Copper Bare	1964	42,228	\$18,689.56	\$0.44	5,626,469	2,573,275.13	\$ 0.46
36500 - Overhead Conductors, Device	Cond Copper Wp	1964	17,829	\$12,323.69	\$0.69	5,644,298	2,585,598.82	\$ 0.46
36500 - Overhead Conductors, Device	Cond All Alum	1964	2,880	\$2,274.99	\$0.79	5,647,178	2,587,873.81	\$ 0.46
36500 - Overhead Conductors, Device	Cond Iron	1964	13,185	\$1,970.39	\$0.15	5,660,363	2,589,844.20	\$ 0.46
36500 - Overhead Conductors, Device	Cond Acsr	1965	224,131	\$169,630.69	\$0.76	5,884,494	2,759,474.89	\$ 0.47
36500 - Overhead Conductors, Device	Cond Alum Wp	1965	78,968	\$83,236.05	\$1.05	5,963,462	2,842,710.94	\$ 0.48
36500 - Overhead Conductors, Device	Insulator	1965	5,460	\$35,602.30	\$6.52	5,968,922	2,878,313.24	\$ 0.48
36500 - Overhead Conductors, Device	Cond All Alum	1965	14,540	\$16,036.99	\$1.10	5,983,462	2,894,350.23	\$ 0.48
36500 - Overhead Conductors, Device	Cond Copper Bare	1965	39,402	\$15,483.76	\$0.39	6,022,864	2,909,833.99	\$ 0.48
36500 - Overhead Conductors, Device	Cond Copper Wp	1965	5,366	\$5,672.83	\$1.06	6,028,230	2,915,506.82	\$ 0.48
36500 - Overhead Conductors, Device	Cond Iron	1965	17,710	\$1,740.38	\$0.10	6,045,940	2,917,247.20	\$ 0.48
36500 - Overhead Conductors, Device	Cond Acsr	1966	280,937	\$211,525.12	\$0.75	6,326,877	3,128,772.32	\$ 0.49
36500 - Overhead Conductors, Device	Cond Alum Wp	1966	97,507	\$93,846.60	\$0.96	6,424,384	3,222,618.92	\$ 0.50
36500 - Overhead Conductors, Device	Insulator	1966	6,880	\$45,258.78	\$6.58	6,431,264	3,267,877.70	\$ 0.51

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Copper Bare	1966	33,811	\$16,582.81	\$0.49	6,465,075	3,284,460.51	\$ 0.51
36500 - Overhead Conductors, Device	Cond All Alum	1966	17,840	\$16,453.88	\$0.92	6,482,915	3,300,914.39	\$ 0.51
36500 - Overhead Conductors, Device	Cond Copper Wp	1966	2,034	\$3,843.19	\$1.89	6,484,949	3,304,757.58	\$ 0.51
36500 - Overhead Conductors, Device	Cond Iron	1966	4,921	\$1,016.75	\$0.21	6,489,870	3,305,774.33	\$ 0.51
36500 - Overhead Conductors, Device	Cond Acsr	1967	266,462	\$217,710.65	\$0.82	6,756,332	3,523,484.98	\$ 0.52
36500 - Overhead Conductors, Device	Cond Alum Wp	1967	117,460	\$117,028.05	\$1.00	6,873,792	3,640,513.03	\$ 0.53
36500 - Overhead Conductors, Device	Insulator	1967	6,813	\$46,412.01	\$6.81	6,880,605	3,686,925.04	\$ 0.54
36500 - Overhead Conductors, Device	Cond Copper Bare	1967	32,922	\$17,204.56	\$0.52	6,913,527	3,704,129.60	\$ 0.54
36500 - Overhead Conductors, Device	Cond All Alum	1967	14,363	\$12,037.83	\$0.84	6,927,890	3,716,167.43	\$ 0.54
36500 - Overhead Conductors, Device	Cond Duplex	1967	19,002	\$3,656.52	\$0.19	6,946,892	3,719,823.95	\$ 0.54
36500 - Overhead Conductors, Device	Cond Iron	1967	4,599	\$2,796.18	\$0.61	6,951,491	3,722,620.13	\$ 0.54
36500 - Overhead Conductors, Device	Cond Copper Wp	1967	1,069	\$2,053.55	\$1.92	6,952,560	3,724,673.68	\$ 0.54
36500 - Overhead Conductors, Device	Cond Triplex	1967	509	\$147.88	\$0.29	6,953,069	3,724,821.56	\$ 0.54
36500 - Overhead Conductors, Device	Cond Acsr	1968	300,554	\$227,592.93	\$0.76	7,253,623	3,952,414.49	\$ 0.54
36500 - Overhead Conductors, Device	Cond Alum Wp	1968	98,908	\$94,833.67	\$0.96	7,352,531	4,047,248.16	\$ 0.55
36500 - Overhead Conductors, Device	Insulator	1968	6,678	\$46,340.34	\$6.94	7,359,209	4,093,588.50	\$ 0.56
36500 - Overhead Conductors, Device	Cond All Alum	1968	22,946	\$17,822.89	\$0.78	7,382,155	4,111,411.39	\$ 0.56
36500 - Overhead Conductors, Device	Cond Copper Bare	1968	14,851	\$12,815.37	\$0.86	7,397,006	4,124,226.76	\$ 0.56
36500 - Overhead Conductors, Device	Cond Duplex	1968	64,193	\$12,235.40	\$0.19	7,461,199	4,136,462.16	\$ 0.55
36500 - Overhead Conductors, Device	Cond Copper Wp	1968	3,534	\$6,788.79	\$1.92	7,464,733	4,143,250.95	\$ 0.56
36500 - Overhead Conductors, Device	Cond Iron	1968	3,163	\$434.69	\$0.14	7,467,896	4,143,685.64	\$ 0.55
36500 - Overhead Conductors, Device	Cond Acsr	1969	331,986	\$277,126.62	\$0.83	7,799,882	4,420,812.26	\$ 0.57
36500 - Overhead Conductors, Device	Cond Alum Wp	1969	127,671	\$141,261.18	\$1.11	7,927,553	4,562,073.44	\$ 0.58
36500 - Overhead Conductors, Device	Insulator	1969	7,108	\$53,059.81	\$7.46	7,934,661	4,615,133.25	\$ 0.58
36500 - Overhead Conductors, Device	Cond All Alum	1969	9,369	\$14,062.58	\$1.50	7,944,030	4,629,195.83	\$ 0.58
36500 - Overhead Conductors, Device	Cond Duplex	1969	78,769	\$10,168.45	\$0.13	8,022,799	4,639,364.28	\$ 0.58
36500 - Overhead Conductors, Device	Cond Copper Bare	1969	5,244	\$9,006.00	\$1.72	8,028,043	4,648,370.28	\$ 0.58
36500 - Overhead Conductors, Device	Cond Copper Wp	1969	1,003	\$3,766.85	\$3.76	8,029,046	4,652,137.13	\$ 0.58
36500 - Overhead Conductors, Device	Cond Iron	1969	1,626	\$1,049.98	\$0.65	8,030,672	4,653,187.11	\$ 0.58
36500 - Overhead Conductors, Device	Cond Triplex	1969	2,483	\$824.31	\$0.33	8,033,155	4,654,011.42	\$ 0.58
36500 - Overhead Conductors, Device	Cond Acsr	1970	341,282	\$301,652.62	\$0.88	8,374,437	4,955,664.04	\$ 0.59

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Alum Wp	1970	111,337	\$120,774.85	\$1.08	8,485,774	5,076,438.89	\$ 0.60
36500 - Overhead Conductors, Device	Insulator	1970	4,868	\$39,661.62	\$8.15	8,490,642	5,116,100.51	\$ 0.60
36500 - Overhead Conductors, Device	Cond All Alum	1970	20,090	\$22,018.81	\$1.10	8,510,732	5,138,119.32	\$ 0.60
36500 - Overhead Conductors, Device	Cond Triplex	1970	29,944	\$10,259.06	\$0.34	8,540,676	5,148,378.38	\$ 0.60
36500 - Overhead Conductors, Device	Cond Duplex	1970	76,935	\$9,873.31	\$0.13	8,617,611	5,158,251.69	\$ 0.60
36500 - Overhead Conductors, Device	Cond Copper Bare	1970	5,027	\$5,369.84	\$1.07	8,622,638	5,163,621.53	\$ 0.60
36500 - Overhead Conductors, Device	Cond Copper Wp	1970	394	\$1,479.70	\$3.76	8,623,032	5,165,101.23	\$ 0.60
36500 - Overhead Conductors, Device	Cond Iron	1970	4,979	\$378.68	\$0.08	8,628,011	5,165,479.91	\$ 0.60
36500 - Overhead Conductors, Device	Cond Acsr	1971	263,075	\$268,822.47	\$1.02	8,891,086	5,434,302.38	\$ 0.61
36500 - Overhead Conductors, Device	Cond Alum Wp	1971	73,207	\$114,597.26	\$1.57	8,964,293	5,548,899.64	\$ 0.62
36500 - Overhead Conductors, Device	Insulator	1971	7,319	\$63,828.86	\$8.72	8,971,612	5,612,728.50	\$ 0.63
36500 - Overhead Conductors, Device	Cond Triplex	1971	116,848	\$45,731.52	\$0.39	9,088,460	5,658,460.02	\$ 0.62
36500 - Overhead Conductors, Device	Cond Duplex	1971	104,560	\$31,243.27	\$0.30	9,193,020	5,689,703.29	\$ 0.62
36500 - Overhead Conductors, Device	Cond All Alum	1971	17,913	\$18,428.73	\$1.03	9,210,933	5,708,132.02	\$ 0.62
36500 - Overhead Conductors, Device	Cond Copper Bare	1971	1,533	\$1,392.32	\$0.91	9,212,466	5,709,524.34	\$ 0.62
36500 - Overhead Conductors, Device	Cond Copper Wp	1971	85	\$319.23	\$3.76	9,212,551	5,709,843.57	\$ 0.62
36500 - Overhead Conductors, Device	Cond Iron	1971	403	\$176.34	\$0.44	9,212,954	5,710,019.91	\$ 0.62
36500 - Overhead Conductors, Device	Cond Acsr	1972	218,578	\$197,141.44	\$0.90	9,431,532	5,907,161.35	\$ 0.63
36500 - Overhead Conductors, Device	Cond Triplex	1972	187,389	\$148,686.65	\$0.79	9,618,921	6,055,848.00	\$ 0.63
36500 - Overhead Conductors, Device	Cond Alum Wp	1972	70,696	\$67,903.35	\$0.96	9,689,617	6,123,751.35	\$ 0.63
36500 - Overhead Conductors, Device	Cond Duplex	1972	97,709	\$63,502.35	\$0.65	9,787,326	6,187,253.70	\$ 0.63
36500 - Overhead Conductors, Device	Insulator	1972	5,944	\$50,962.97	\$8.57	9,793,270	6,238,216.67	\$ 0.64
36500 - Overhead Conductors, Device	Cond All Alum	1972	41,812	\$30,785.63	\$0.74	9,835,082	6,269,002.30	\$ 0.64
36500 - Overhead Conductors, Device	Cond Copper Bare	1972	15,327	\$6,756.03	\$0.44	9,850,409	6,275,758.33	\$ 0.64
36500 - Overhead Conductors, Device	Cond Copper Wp	1972	93	\$349.27	\$3.76	9,850,502	6,276,107.60	\$ 0.64
36500 - Overhead Conductors, Device	Cond Quadruplex	1972	157	\$88.82	\$0.57	9,850,659	6,276,196.42	\$ 0.64
36500 - Overhead Conductors, Device	Cond Iron	1972	1,487	\$66.90	\$0.04	9,852,146	6,276,263.32	\$ 0.64
36500 - Overhead Conductors, Device	Cond Acsr	1973	210,625	\$240,444.31	\$1.14	10,062,771	6,516,707.63	\$ 0.65
36500 - Overhead Conductors, Device	Cond Triplex	1973	151,086	\$95,321.38	\$0.63	10,213,857	6,612,029.01	\$ 0.65
36500 - Overhead Conductors, Device	Cond Alum Wp	1973	31,849	\$53,603.24	\$1.68	10,245,706	6,665,632.25	\$ 0.65
36500 - Overhead Conductors, Device	Insulator	1973	5,688	\$47,812.57	\$8.41	10,251,394	6,713,444.82	\$ 0.65

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Duplex	1973	100,881	\$42,133.73	\$0.42	10,352,275	6,755,578.55	\$ 0.65
36500 - Overhead Conductors, Device	Cond All Alum	1973	33,095	\$20,472.35	\$0.62	10,385,370	6,776,050.90	\$ 0.65
36500 - Overhead Conductors, Device	Cond Copper Bare	1973	5,484	\$1,147.99	\$0.21	10,390,854	6,777,198.89	\$ 0.65
36500 - Overhead Conductors, Device	Cond Copper Wp	1973	277	\$1,040.29	\$3.76	10,391,131	6,778,239.18	\$ 0.65
36500 - Overhead Conductors, Device	Cond Iron	1973	419	\$453.64	\$1.08	10,391,550	6,778,692.82	\$ 0.65
36500 - Overhead Conductors, Device	Cond Acsr	1974	198,737	\$193,590.72	\$0.97	10,590,287	6,972,283.54	\$ 0.66
36500 - Overhead Conductors, Device	Cond Triplex	1974	161,275	\$71,990.62	\$0.45	10,751,562	7,044,274.16	\$ 0.66
36500 - Overhead Conductors, Device	Insulator	1974	5,245	\$49,023.13	\$9.35	10,756,807	7,093,297.29	\$ 0.66
36500 - Overhead Conductors, Device	Cond Alum Wp	1974	37,524	\$28,095.51	\$0.75	10,794,331	7,121,392.80	\$ 0.66
36500 - Overhead Conductors, Device	Cond Duplex	1974	78,532	\$17,252.58	\$0.22	10,872,863	7,138,645.38	\$ 0.66
36500 - Overhead Conductors, Device	Cond All Alum	1974	23,420	\$15,122.22	\$0.65	10,896,283	7,153,767.60	\$ 0.66
36500 - Overhead Conductors, Device	Cond Copper Wp	1974	176	\$660.98	\$3.76	10,896,459	7,154,428.58	\$ 0.66
36500 - Overhead Conductors, Device	Cond Copper Bare	1974	707	\$458.60	\$0.65	10,897,166	7,154,887.18	\$ 0.66
36500 - Overhead Conductors, Device	Cond Iron	1974	79	\$88.49	\$1.12	10,897,245	7,154,975.67	\$ 0.66
36500 - Overhead Conductors, Device	Cond Acsr	1975	147,295	\$247,991.44	\$1.68	11,044,540	7,402,967.11	\$ 0.67
36500 - Overhead Conductors, Device	Cond Triplex	1975	121,875	\$102,913.43	\$0.84	11,166,415	7,505,880.54	\$ 0.67
36500 - Overhead Conductors, Device	Cond Duplex	1975	79,454	\$66,717.36	\$0.84	11,245,869	7,572,597.90	\$ 0.67
36500 - Overhead Conductors, Device	Insulator	1975	3,536	\$35,110.41	\$9.93	11,249,405	7,607,708.31	\$ 0.68
36500 - Overhead Conductors, Device	Cond All Alum	1975	32,166	\$19,563.52	\$0.61	11,281,571	7,627,271.83	\$ 0.68
36500 - Overhead Conductors, Device	Cond Alum Wp	1975	17,113	\$18,266.25	\$1.07	11,298,684	7,645,538.08	\$ 0.68
36500 - Overhead Conductors, Device	Cond Copper Wp	1975	234	\$878.80	\$3.76	11,298,918	7,646,416.88	\$ 0.68
36500 - Overhead Conductors, Device	Cond Quadruplex	1975	251	\$180.09	\$0.72	11,299,169	7,646,596.97	\$ 0.68
36500 - Overhead Conductors, Device	Cond Iron	1975	46	\$49.68	\$1.08	11,299,215	7,646,646.65	\$ 0.68
36500 - Overhead Conductors, Device	Cond Copper Bare	1975	76	\$37.94	\$0.50	11,299,291	7,646,684.59	\$ 0.68
36500 - Overhead Conductors, Device	Cond Acsr	1976	181,000	\$297,066.66	\$1.64	11,480,291	7,943,751.25	\$ 0.69
36500 - Overhead Conductors, Device	Cond Triplex	1976	161,908	\$138,538.32	\$0.86	11,642,199	8,082,289.57	\$ 0.69
36500 - Overhead Conductors, Device	Cond Duplex	1976	90,542	\$77,050.26	\$0.85	11,732,741	8,159,339.83	\$ 0.70
36500 - Overhead Conductors, Device	Insulator	1976	5,006	\$56,999.77	\$11.39	11,737,747	8,216,339.60	\$ 0.70
36500 - Overhead Conductors, Device	Cond All Alum	1976	38,843	\$55,855.72	\$1.44	11,776,590	8,272,195.32	\$ 0.70
36500 - Overhead Conductors, Device	Cond Alum Wp	1976	24,049	\$24,186.42	\$1.01	11,800,639	8,296,381.74	\$ 0.70
36500 - Overhead Conductors, Device	Cond Quadruplex	1976	1,373	\$1,204.72	\$0.88	11,802,012	8,297,586.46	\$ 0.70

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Copper Wp	1976	45	\$169.00	\$3.76	11,802,057	8,297,755.46	\$ 0.70
36500 - Overhead Conductors, Device	Cond Copper Bare	1976	259	\$152.75	\$0.59	11,802,316	8,297,908.21	\$ 0.70
36500 - Overhead Conductors, Device	Cond Iron	1976	5,228	\$52.15	\$0.01	11,807,544	8,297,960.36	\$ 0.70
36500 - Overhead Conductors, Device	Cond Acsr	1977	245,972	\$260,861.05	\$1.06	12,053,516	8,558,821.41	\$ 0.71
36500 - Overhead Conductors, Device	Cond Triplex	1977	138,941	\$139,293.85	\$1.00	12,192,457	8,698,115.26	\$ 0.71
36500 - Overhead Conductors, Device	Cond Alum Wp	1977	57,180	\$108,834.94	\$1.90	12,249,637	8,806,950.20	\$ 0.72
36500 - Overhead Conductors, Device	Insulator	1977	6,081	\$75,013.89	\$12.34	12,255,718	8,881,964.09	\$ 0.72
36500 - Overhead Conductors, Device	Cond All Alum	1977	64,632	\$71,780.88	\$1.11	12,320,350	8,953,744.97	\$ 0.73
36500 - Overhead Conductors, Device	Cond Duplex	1977	76,593	\$26,888.01	\$0.35	12,396,943	8,980,632.98	\$ 0.72
36500 - Overhead Conductors, Device	Cond Quadruplex	1977	10,228	\$14,075.91	\$1.38	12,407,171	8,994,708.89	\$ 0.72
36500 - Overhead Conductors, Device	Cond Copper Wp	1977	56	\$58.06	\$1.04	12,407,227	8,994,766.95	\$ 0.72
36500 - Overhead Conductors, Device	Cond Copper Bare	1977	91	\$46.84	\$0.51	12,407,318	8,994,813.79	\$ 0.72
36500 - Overhead Conductors, Device	Cond Iron	1977	2	\$0.42	\$0.21	12,407,320	8,994,814.21	\$ 0.72
36500 - Overhead Conductors, Device	Cond Acsr	1978	101,650	\$166,073.06	\$1.63	12,508,970	9,160,887.27	\$ 0.73
36500 - Overhead Conductors, Device	Cond Triplex	1978	137,836	\$163,586.91	\$1.19	12,646,806	9,324,474.18	\$ 0.74
36500 - Overhead Conductors, Device	Insulator	1978	5,333	\$71,229.33	\$13.36	12,652,139	9,395,703.51	\$ 0.74
36500 - Overhead Conductors, Device	Cond Alum Wp	1978	21,689	\$49,604.66	\$2.29	12,673,828	9,445,308.17	\$ 0.75
36500 - Overhead Conductors, Device	Cond Duplex	1978	73,239	\$31,273.04	\$0.43	12,747,067	9,476,581.21	\$ 0.74
36500 - Overhead Conductors, Device	Cond Quadruplex	1978	18,139	\$29,167.37	\$1.61	12,765,206	9,505,748.58	\$ 0.74
36500 - Overhead Conductors, Device	Cond All Alum	1978	13,258	\$27,563.73	\$2.08	12,778,464	9,533,312.31	\$ 0.75
36500 - Overhead Conductors, Device	Cond Copper Bare	1978	769	\$1,041.69	\$1.35	12,779,233	9,534,354.00	\$ 0.75
36500 - Overhead Conductors, Device	Cond Copper Wp	1978	134	\$168.80	\$1.26	12,779,367	9,534,522.80	\$ 0.75
36500 - Overhead Conductors, Device	Cond Iron	1978	2,374	\$30.09	\$0.01	12,781,741	9,534,552.89	\$ 0.75
36500 - Overhead Conductors, Device	Cond Acsr	1979	175,804	\$307,503.50	\$1.75	12,957,545	9,842,056.39	\$ 0.76
36500 - Overhead Conductors, Device	Cond Triplex	1979	132,882	\$175,692.58	\$1.32	13,090,427	10,017,748.97	\$ 0.77
36500 - Overhead Conductors, Device	Insulator	1979	6,095	\$81,180.38	\$13.32	13,096,522	10,098,929.35	\$ 0.77
36500 - Overhead Conductors, Device	Cond All Alum	1979	30,581	\$72,063.06	\$2.36	13,127,103	10,170,992.41	\$ 0.77
36500 - Overhead Conductors, Device	Cond Alum Wp	1979	24,049	\$61,691.00	\$2.57	13,151,152	10,232,683.41	\$ 0.78
36500 - Overhead Conductors, Device	Cond Duplex	1979	76,586	\$38,135.42	\$0.50	13,227,738	10,270,818.83	\$ 0.78
36500 - Overhead Conductors, Device	Cond Quadruplex	1979	20,026	\$35,322.21	\$1.76	13,247,764	10,306,141.04	\$ 0.78
36500 - Overhead Conductors, Device	Cond Copper Bare	1979	479	\$636.82	\$1.33	13,248,243	10,306,777.86	\$ 0.78

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Copper Wp	1979	18	\$26.25	\$1.46	13,248,261	10,306,804.11	\$ 0.78
36500 - Overhead Conductors, Device	Cond Acsr	1980	158,954	\$309,361.77	\$1.95	13,407,215	10,616,165.88	\$ 0.79
36500 - Overhead Conductors, Device	Cond Triplex	1980	177,617	\$255,982.10	\$1.44	13,584,832	10,872,147.98	\$ 0.80
36500 - Overhead Conductors, Device	Cond Alum Wp	1980	43,659	\$122,370.27	\$2.80	13,628,491	10,994,518.25	\$ 0.81
36500 - Overhead Conductors, Device	Insulator	1980	5,647	\$91,561.35	\$16.21	13,634,138	11,086,079.60	\$ 0.81
36500 - Overhead Conductors, Device	Cond Duplex	1980	75,854	\$42,943.84	\$0.57	13,709,992	11,129,023.44	\$ 0.81
36500 - Overhead Conductors, Device	Cond Quadruplex	1980	22,050	\$41,386.70	\$1.88	13,732,042	11,170,410.14	\$ 0.81
36500 - Overhead Conductors, Device	Cond All Alum	1980	9,848	\$25,381.55	\$2.58	13,741,890	11,195,791.69	\$ 0.81
36500 - Overhead Conductors, Device	Cond Copper Bare	1980	108	\$193.97	\$1.80	13,741,998	11,195,985.66	\$ 0.81
36500 - Overhead Conductors, Device	Cond Copper Wp	1980	21	\$34.64	\$1.65	13,742,019	11,196,020.30	\$ 0.81
36500 - Overhead Conductors, Device	Cond Iron	1980	171	\$4.27	\$0.02	13,742,190	11,196,024.57	\$ 0.81
36500 - Overhead Conductors, Device	Cond Acsr	1981	128,447	\$301,502.10	\$2.35	13,870,637	11,497,526.67	\$ 0.83
36500 - Overhead Conductors, Device	Cond Triplex	1981	150,877	\$251,783.60	\$1.67	14,021,514	11,749,310.27	\$ 0.84
36500 - Overhead Conductors, Device	Cond Alum Wp	1981	33,940	\$111,204.93	\$3.28	14,055,454	11,860,515.20	\$ 0.84
36500 - Overhead Conductors, Device	Insulator	1981	6,366	\$108,731.20	\$17.08	14,061,820	11,969,246.40	\$ 0.85
36500 - Overhead Conductors, Device	Cond All Alum	1981	31,987	\$96,398.40	\$3.01	14,093,807	12,065,644.80	\$ 0.86
36500 - Overhead Conductors, Device	Cond Duplex	1981	67,426	\$44,682.01	\$0.66	14,161,233	12,110,326.81	\$ 0.86
36500 - Overhead Conductors, Device	Cond Quadruplex	1981	18,045	\$38,668.35	\$2.14	14,179,278	12,148,995.16	\$ 0.86
36500 - Overhead Conductors, Device	Cond Copper Bare	1981	57	\$132.28	\$2.32	14,179,335	12,149,127.44	\$ 0.86
36500 - Overhead Conductors, Device	Cond Copper Wp	1981	25	\$49.04	\$1.96	14,179,360	12,149,176.48	\$ 0.86
36500 - Overhead Conductors, Device	Cond Acsr	1982	199,150	\$611,465.40	\$3.07	14,378,510	12,760,641.88	\$ 0.89
36500 - Overhead Conductors, Device	Cond Triplex	1982	172,047	\$365,749.48	\$2.13	14,550,557	13,126,391.36	\$ 0.90
36500 - Overhead Conductors, Device	Cond Alum Wp	1982	43,740	\$185,894.12	\$4.25	14,594,297	13,312,285.48	\$ 0.91
36500 - Overhead Conductors, Device	Insulator	1982	7,478	\$134,753.51	\$18.02	14,601,775	13,447,038.99	\$ 0.92
36500 - Overhead Conductors, Device	Cond Duplex	1982	76,515	\$69,115.99	\$0.90	14,678,290	13,516,154.98	\$ 0.92
36500 - Overhead Conductors, Device	Cond All Alum	1982	17,230	\$67,415.44	\$3.91	14,695,520	13,583,570.42	\$ 0.92
36500 - Overhead Conductors, Device	Cond Quadruplex	1982	15,159	\$40,813.02	\$2.69	14,710,679	13,624,383.44	\$ 0.93
36500 - Overhead Conductors, Device	Cond Copper Bare	1982	238	\$682.48	\$2.87	14,710,917	13,625,065.92	\$ 0.93
36500 - Overhead Conductors, Device	Cond Copper Wp	1982	38	\$99.18	\$2.61	14,710,955	13,625,165.10	\$ 0.93
36500 - Overhead Conductors, Device	Cond Acsr	1983	99,400	\$271,135.42	\$2.73	14,810,355	13,896,300.52	\$ 0.94
36500 - Overhead Conductors, Device	Cond Triplex	1983	128,772	\$247,137.77	\$1.92	14,939,127	14,143,438.29	\$ 0.95

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Insulator	1983	8,926	\$163,806.36	\$18.35	14,948,053	14,307,244.65	\$ 0.96
36500 - Overhead Conductors, Device	Cond Duplex	1983	73,372	\$56,485.37	\$0.77	15,021,425	14,363,730.02	\$ 0.96
36500 - Overhead Conductors, Device	Cond All Alum	1983	12,229	\$40,602.17	\$3.32	15,033,654	14,404,332.19	\$ 0.96
36500 - Overhead Conductors, Device	Cond Alum Wp	1983	9,610	\$34,830.63	\$3.62	15,043,264	14,439,162.82	\$ 0.96
36500 - Overhead Conductors, Device	Cond Quadruplex	1983	14,588	\$32,376.38	\$2.22	15,057,852	14,471,539.20	\$ 0.96
36500 - Overhead Conductors, Device	Cond Copper Bare	1983	3,142	\$9,090.25	\$2.89	15,060,994	14,480,629.45	\$ 0.96
36500 - Overhead Conductors, Device	Cond Copper Wp	1983	16	\$35.88	\$2.24	15,061,010	14,480,665.33	\$ 0.96
36500 - Overhead Conductors, Device	Cond Acsr	1984	148,485	\$364,456.17	\$2.45	15,209,495	14,845,121.50	\$ 0.98
36500 - Overhead Conductors, Device	Cond Triplex	1984	120,237	\$347,307.19	\$2.89	15,329,732	15,192,428.69	\$ 0.99
36500 - Overhead Conductors, Device	Insulator	1984	9,848	\$133,866.61	\$13.59	15,339,580	15,326,295.30	\$ 1.00
36500 - Overhead Conductors, Device	Cond Alum Wp	1984	15,576	\$65,525.49	\$4.21	15,355,156	15,391,820.79	\$ 1.00
36500 - Overhead Conductors, Device	Cond All Alum	1984	24,254	\$65,208.58	\$2.69	15,379,410	15,457,029.37	\$ 1.01
36500 - Overhead Conductors, Device	Cond Quadruplex	1984	19,943	\$45,787.21	\$2.30	15,399,353	15,502,816.58	\$ 1.01
36500 - Overhead Conductors, Device	Cond Duplex	1984	59,968	\$37,860.35	\$0.63	15,459,321	15,540,676.93	\$ 1.01
36500 - Overhead Conductors, Device	Cond Copper Bare	1984	2,177	\$6,598.48	\$3.03	15,461,498	15,547,275.41	\$ 1.01
36500 - Overhead Conductors, Device	Cond Acsr	1985	249,267	\$612,907.94	\$2.46	15,710,765	16,160,183.35	\$ 1.03
36500 - Overhead Conductors, Device	Insulator	1985	17,532	\$310,913.22	\$17.73	15,728,297	16,471,096.57	\$ 1.05
36500 - Overhead Conductors, Device	Cond Triplex	1985	105,923	\$300,689.79	\$2.84	15,834,220	16,771,786.36	\$ 1.06
36500 - Overhead Conductors, Device	Cond All Alum	1985	46,401	\$131,092.28	\$2.83	15,880,621	16,902,878.64	\$ 1.06
36500 - Overhead Conductors, Device	Cond Alum Wp	1985	20,451	\$86,604.47	\$4.23	15,901,072	16,989,483.11	\$ 1.07
36500 - Overhead Conductors, Device	Cond Duplex	1985	67,815	\$76,214.44	\$1.12	15,968,887	17,065,697.55	\$ 1.07
36500 - Overhead Conductors, Device	Cond Quadruplex	1985	17,919	\$54,603.36	\$3.05	15,986,806	17,120,300.91	\$ 1.07
36500 - Overhead Conductors, Device	Cond Copper Bare	1985	5,702	\$25,719.26	\$4.51	15,992,508	17,146,020.17	\$ 1.07
36500 - Overhead Conductors, Device	Cond Acsr	1986	119,806	\$287,425.48	\$2.40	16,112,314	17,433,445.65	\$ 1.08
36500 - Overhead Conductors, Device	Insulator	1986	10,796	\$267,309.91	\$24.76	16,123,110	17,700,755.56	\$ 1.10
36500 - Overhead Conductors, Device	Cond Triplex	1986	87,143	\$219,946.69	\$2.52	16,210,253	17,920,702.25	\$ 1.11
36500 - Overhead Conductors, Device	Cond Quadruplex	1986	20,475	\$73,404.89	\$3.59	16,230,728	17,994,107.14	\$ 1.11
36500 - Overhead Conductors, Device	Cond Duplex	1986	62,175	\$69,842.44	\$1.12	16,292,903	18,063,949.58	\$ 1.11
36500 - Overhead Conductors, Device	Cond Alum Wp	1986	9,880	\$44,553.72	\$4.51	16,302,783	18,108,503.30	\$ 1.11
36500 - Overhead Conductors, Device	Cond Copper Bare	1986	4,129	\$23,438.14	\$5.68	16,306,912	18,131,941.44	\$ 1.11
36500 - Overhead Conductors, Device	Cond All Alum	1986	4,039	\$15,066.23	\$3.73	16,310,951	18,147,007.67	\$ 1.11

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Copper Wp	1986	24	\$91.74	\$3.82	16,310,975	18,147,099.41	\$ 1.11
36500 - Overhead Conductors, Device	Cond Acsr	1987	151,236	\$374,861.99	\$2.48	16,462,211	18,521,961.40	\$ 1.13
36500 - Overhead Conductors, Device	Cond Triplex	1987	116,451	\$286,793.62	\$2.46	16,578,662	18,808,755.02	\$ 1.13
36500 - Overhead Conductors, Device	Insulator	1987	10,973	\$272,467.05	\$24.83	16,589,635	19,081,222.07	\$ 1.15
36500 - Overhead Conductors, Device	Cond Duplex	1987	91,693	\$115,073.24	\$1.25	16,681,328	19,196,295.31	\$ 1.15
36500 - Overhead Conductors, Device	Cond Quadruplex	1987	16,036	\$55,240.40	\$3.44	16,697,364	19,251,535.71	\$ 1.15
36500 - Overhead Conductors, Device	Cond All Alum	1987	12,197	\$42,007.19	\$3.44	16,709,561	19,293,542.90	\$ 1.15
36500 - Overhead Conductors, Device	Cond Alum Wp	1987	8,274	\$40,144.69	\$4.85	16,717,835	19,333,687.59	\$ 1.16
36500 - Overhead Conductors, Device	Cond Copper Bare	1987	6,204	\$30,024.49	\$4.84	16,724,039	19,363,712.08	\$ 1.16
36500 - Overhead Conductors, Device	Cond Copper Wp	1987	20	\$94.74	\$4.74	16,724,059	19,363,806.82	\$ 1.16
36500 - Overhead Conductors, Device	Cond Iron	1987	606	\$11.10	\$0.02	16,724,665	19,363,817.92	\$ 1.16
36500 - Overhead Conductors, Device	Insulator	1988	10,580	\$405,919.52	\$38.37	16,735,245	19,769,737.44	\$ 1.18
36500 - Overhead Conductors, Device	Cond Triplex	1988	90,492	\$260,757.02	\$2.88	16,825,737	20,030,494.46	\$ 1.19
36500 - Overhead Conductors, Device	Cond Acsr	1988	87,496	\$251,107.10	\$2.87	16,913,233	20,281,601.56	\$ 1.20
36500 - Overhead Conductors, Device	Cond Duplex	1988	81,252	\$118,624.45	\$1.46	16,994,485	20,400,226.01	\$ 1.20
36500 - Overhead Conductors, Device	Cond Quadruplex	1988	13,797	\$54,003.49	\$3.91	17,008,282	20,454,229.50	\$ 1.20
36500 - Overhead Conductors, Device	Cond All Alum	1988	6,013	\$26,437.56	\$4.40	17,014,295	20,480,667.06	\$ 1.20
36500 - Overhead Conductors, Device	Cond Alum Wp	1988	3,025	\$16,408.37	\$5.42	17,017,320	20,497,075.43	\$ 1.20
36500 - Overhead Conductors, Device	Cond Copper Bare	1988	3,284	\$16,071.08	\$4.89	17,020,604	20,513,146.51	\$ 1.21
36500 - Overhead Conductors, Device	Cond Copper Wp	1988	29	\$132.63	\$4.57	17,020,633	20,513,279.14	\$ 1.21
36500 - Overhead Conductors, Device	Cond Acsr	1989	92,767	\$328,967.41	\$3.55	17,113,400	20,842,246.55	\$ 1.22
36500 - Overhead Conductors, Device	Cond Triplex	1989	97,819	\$281,692.55	\$2.88	17,211,219	21,123,939.10	\$ 1.23
36500 - Overhead Conductors, Device	Insulator	1989	7,715	\$277,781.91	\$36.01	17,218,934	21,401,721.01	\$ 1.24
36500 - Overhead Conductors, Device	Cond Duplex	1989	87,784	\$138,643.44	\$1.58	17,306,718	21,540,364.45	\$ 1.24
36500 - Overhead Conductors, Device	Cond Quadruplex	1989	11,743	\$49,415.87	\$4.21	17,318,461	21,589,780.32	\$ 1.25
36500 - Overhead Conductors, Device	Cond Alum Wp	1989	2,726	\$14,093.12	\$5.17	17,321,187	21,603,873.44	\$ 1.25
36500 - Overhead Conductors, Device	Cond All Alum	1989	1,239	\$6,053.88	\$4.89	17,322,426	21,609,927.32	\$ 1.25
36500 - Overhead Conductors, Device	Cond Copper Bare	1989	856	\$4,894.11	\$5.72	17,323,282	21,614,821.43	\$ 1.25
36500 - Overhead Conductors, Device	Insulator	1990	8,938	\$355,737.31	\$39.80	17,332,220	21,970,558.74	\$ 1.27
36500 - Overhead Conductors, Device	Cond Acsr	1990	78,930	\$280,998.64	\$3.56	17,411,150	22,251,557.38	\$ 1.28
36500 - Overhead Conductors, Device	Cond Triplex	1990	93,474	\$244,362.32	\$2.61	17,504,624	22,495,919.70	\$ 1.29

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Duplex	1990	81,019	\$115,707.26	\$1.43	17,585,643	22,611,626.96	\$ 1.29
36500 - Overhead Conductors, Device	Cond All Alum	1990	11,192	\$55,639.67	\$4.97	17,596,835	22,667,266.63	\$ 1.29
36500 - Overhead Conductors, Device	Cond Quadruplex	1990	13,893	\$50,264.42	\$3.62	17,610,728	22,717,531.05	\$ 1.29
36500 - Overhead Conductors, Device	Cond Alum Wp	1990	2,610	\$13,440.77	\$5.15	17,613,338	22,730,971.82	\$ 1.29
36500 - Overhead Conductors, Device	Cond Copper Bare	1990	1,429	\$6,594.89	\$4.62	17,614,767	22,737,566.71	\$ 1.29
36500 - Overhead Conductors, Device	Cond Acsr	1991	85,828	\$296,500.87	\$3.45	17,700,595	23,034,067.58	\$ 1.30
36500 - Overhead Conductors, Device	Insulator	1991	7,955	\$292,847.84	\$36.81	17,708,550	23,326,915.42	\$ 1.32
36500 - Overhead Conductors, Device	Cond Triplex	1991	100,616	\$262,792.48	\$2.61	17,809,166	23,589,707.90	\$ 1.32
36500 - Overhead Conductors, Device	Cond Duplex	1991	106,419	\$138,043.10	\$1.30	17,915,585	23,727,751.00	\$ 1.32
36500 - Overhead Conductors, Device	Cond Quadruplex	1991	16,639	\$60,545.65	\$3.64	17,932,224	23,788,296.65	\$ 1.33
36500 - Overhead Conductors, Device	Cond Alum Wp	1991	2,681	\$16,449.20	\$6.14	17,934,905	23,804,745.85	\$ 1.33
36500 - Overhead Conductors, Device	Cond Copper Bare	1991	2,788	\$11,360.60	\$4.07	17,937,693	23,816,106.45	\$ 1.33
36500 - Overhead Conductors, Device	Cond Copper Wp	1991	6	\$2.82	\$0.47	17,937,699	23,816,109.27	\$ 1.33
36500 - Overhead Conductors, Device	Cond Acsr	1992	70,612	\$283,297.10	\$4.01	18,008,311	24,099,406.37	\$ 1.34
36500 - Overhead Conductors, Device	Insulator	1992	6,624	\$270,076.80	\$40.77	18,014,935	24,369,483.17	\$ 1.35
36500 - Overhead Conductors, Device	Cond Triplex	1992	80,884	\$234,437.90	\$2.90	18,095,819	24,603,921.07	\$ 1.36
36500 - Overhead Conductors, Device	Cond Duplex	1992	107,984	\$149,786.56	\$1.39	18,203,803	24,753,707.63	\$ 1.36
36500 - Overhead Conductors, Device	Cond All Alum	1992	22,311	\$107,242.76	\$4.81	18,226,114	24,860,950.39	\$ 1.36
36500 - Overhead Conductors, Device	Cond Quadruplex	1992	11,309	\$52,719.89	\$4.66	18,237,423	24,913,670.28	\$ 1.37
36500 - Overhead Conductors, Device	Cond Alum Wp	1992	3,654	\$18,085.65	\$4.95	18,241,077	24,931,755.93	\$ 1.37
36500 - Overhead Conductors, Device	Cond Copper Bare	1992	1,109	\$5,476.20	\$4.94	18,242,186	24,937,232.13	\$ 1.37
36500 - Overhead Conductors, Device	Cond Copper Wp	1992	184	\$758.08	\$4.12	18,242,370	24,937,990.21	\$ 1.37
36500 - Overhead Conductors, Device	Cond Acsr	1993	116,520	\$457,944.37	\$3.93	18,358,890	25,395,934.58	\$ 1.38
36500 - Overhead Conductors, Device	Insulator	1993	9,334	\$341,008.19	\$36.53	18,368,224	25,736,942.77	\$ 1.40
36500 - Overhead Conductors, Device	Cond Triplex	1993	91,399	\$275,987.32	\$3.02	18,459,623	26,012,930.09	\$ 1.41
36500 - Overhead Conductors, Device	Cond Duplex	1993	97,497	\$139,892.52	\$1.43	18,557,120	26,152,822.61	\$ 1.41
36500 - Overhead Conductors, Device	Cond Quadruplex	1993	14,007	\$62,560.65	\$4.47	18,571,127	26,215,383.26	\$ 1.41
36500 - Overhead Conductors, Device	Cond All Alum	1993	8,240	\$54,973.07	\$6.67	18,579,367	26,270,356.33	\$ 1.41
36500 - Overhead Conductors, Device	Cond Alum Wp	1993	3,575	\$19,606.94	\$5.48	18,582,942	26,289,963.27	\$ 1.41
36500 - Overhead Conductors, Device	Cond Copper Bare	1993	1,932	\$8,385.38	\$4.34	18,584,874	26,298,348.65	\$ 1.42
36500 - Overhead Conductors, Device	Cond Copper Wp	1993	16	\$11.36	\$0.71	18,584,890	26,298,360.01	\$ 1.42

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Insulator	1994	6,802	\$311,895.93	\$45.85	18,591,692	26,610,255.94	\$ 1.43
36500 - Overhead Conductors, Device	Cond Acsr	1994	78,638	\$287,982.61	\$3.66	18,670,330	26,898,238.55	\$ 1.44
36500 - Overhead Conductors, Device	Cond Triplex	1994	76,259	\$256,457.31	\$3.36	18,746,589	27,154,695.86	\$ 1.45
36500 - Overhead Conductors, Device	Cond Duplex	1994	79,641	\$138,957.54	\$1.74	18,826,230	27,293,653.40	\$ 1.45
36500 - Overhead Conductors, Device	Cond Quadruplex	1994	10,707	\$46,793.62	\$4.37	18,836,937	27,340,447.02	\$ 1.45
36500 - Overhead Conductors, Device	Cond Alum Wp	1994	4,062	\$25,391.90	\$6.25	18,840,999	27,365,838.92	\$ 1.45
36500 - Overhead Conductors, Device	Cond All Alum	1994	5,051	\$20,366.05	\$4.03	18,846,050	27,386,204.97	\$ 1.45
36500 - Overhead Conductors, Device	Cond Copper Bare	1994	2,078	\$11,340.25	\$5.46	18,848,128	27,397,545.22	\$ 1.45
36500 - Overhead Conductors, Device	Cond Acsr	1995	118,741	\$422,644.52	\$3.56	18,966,869	27,820,189.74	\$ 1.47
36500 - Overhead Conductors, Device	Cond Triplex	1995	89,428	\$311,466.02	\$3.48	19,056,297	28,131,655.76	\$ 1.48
36500 - Overhead Conductors, Device	Insulator	1995	6,192	\$298,142.17	\$48.15	19,062,489	28,429,797.93	\$ 1.49
36500 - Overhead Conductors, Device	Cond Duplex	1995	94,572	\$164,119.19	\$1.74	19,157,061	28,593,917.12	\$ 1.49
36500 - Overhead Conductors, Device	Cond Quadruplex	1995	10,981	\$50,509.06	\$4.60	19,168,042	28,644,426.18	\$ 1.49
36500 - Overhead Conductors, Device	Cond All Alum	1995	5,385	\$27,626.66	\$5.13	19,173,427	28,672,052.84	\$ 1.50
36500 - Overhead Conductors, Device	Cond Alum Wp	1995	2,940	\$16,151.60	\$5.49	19,176,367	28,688,204.44	\$ 1.50
36500 - Overhead Conductors, Device	Cond Copper Bare	1995	1,316	\$7,065.55	\$5.37	19,177,683	28,695,269.99	\$ 1.50
36500 - Overhead Conductors, Device	Cond Copper Wp	1995	200	\$354.37	\$1.77	19,177,883	28,695,624.36	\$ 1.50
36500 - Overhead Conductors, Device	Insulator	1996	5,879	\$352,220.76	\$59.91	19,183,762	29,047,845.12	\$ 1.51
36500 - Overhead Conductors, Device	Cond Triplex	1996	74,345	\$273,396.47	\$3.68	19,258,107	29,321,241.59	\$ 1.52
36500 - Overhead Conductors, Device	Cond Acsr	1996	60,290	\$232,558.01	\$3.86	19,318,397	29,553,799.60	\$ 1.53
36500 - Overhead Conductors, Device	Cond Duplex	1996	85,559	\$163,157.51	\$1.91	19,403,956	29,716,957.11	\$ 1.53
36500 - Overhead Conductors, Device	Cond Quadruplex	1996	10,813	\$57,053.35	\$5.28	19,414,769	29,774,010.46	\$ 1.53
36500 - Overhead Conductors, Device	Cond All Alum	1996	4,335	\$48,388.64	\$11.16	19,419,104	29,822,399.10	\$ 1.54
36500 - Overhead Conductors, Device	Cond Alum Wp	1996	3,328	\$15,079.70	\$4.53	19,422,432	29,837,478.80	\$ 1.54
36500 - Overhead Conductors, Device	Cond Copper Bare	1996	261	\$2,238.96	\$8.58	19,422,693	29,839,717.76	\$ 1.54
36500 - Overhead Conductors, Device	Cond Copper Wp	1996	387	\$568.64	\$1.47	19,423,080	29,840,286.40	\$ 1.54
36500 - Overhead Conductors, Device	Cond Acsr	1997	106,814	\$453,549.41	\$4.25	19,529,894	30,293,835.81	\$ 1.55
36500 - Overhead Conductors, Device	Cond Triplex	1997	96,019	\$327,607.98	\$3.41	19,625,913	30,621,443.79	\$ 1.56
36500 - Overhead Conductors, Device	Insulator	1997	4,776	\$264,918.90	\$55.47	19,630,689	30,886,362.69	\$ 1.57
36500 - Overhead Conductors, Device	Cond Duplex	1997	84,454	\$154,100.01	\$1.82	19,715,143	31,040,462.70	\$ 1.57
36500 - Overhead Conductors, Device	Cond Quadruplex	1997	11,047	\$58,968.11	\$5.34	19,726,190	31,099,430.81	\$ 1.58

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond All Alum	1997	7,966	\$57,561.61	\$7.23	19,734,156	31,156,992.42	\$ 1.58
36500 - Overhead Conductors, Device	Cond Alum Wp	1997	4,958	\$28,546.22	\$5.76	19,739,114	31,185,538.64	\$ 1.58
36500 - Overhead Conductors, Device	Cond Copper Bare	1997	883	\$13,414.76	\$15.19	19,739,997	31,198,953.40	\$ 1.58
36500 - Overhead Conductors, Device	Cond Copper Wp	1997	735	\$1,981.29	\$2.70	19,740,732	31,200,934.69	\$ 1.58
36500 - Overhead Conductors, Device	Insulator	1998	5,918	\$281,819.70	\$47.62	19,746,650	31,482,754.39	\$ 1.59
36500 - Overhead Conductors, Device	Cond Acsr	1998	76,437	\$255,237.44	\$3.34	19,823,087	31,737,991.83	\$ 1.60
36500 - Overhead Conductors, Device	Cond Triplex	1998	53,708	\$150,771.86	\$2.81	19,876,795	31,888,763.69	\$ 1.60
36500 - Overhead Conductors, Device	Cond Duplex	1998	65,897	\$92,508.62	\$1.40	19,942,692	31,981,272.31	\$ 1.60
36500 - Overhead Conductors, Device	Cond Quadruplex	1998	10,537	\$41,832.75	\$3.97	19,953,229	32,023,105.06	\$ 1.60
36500 - Overhead Conductors, Device	Cond All Alum	1998	5,307	\$35,994.40	\$6.78	19,958,536	32,059,099.46	\$ 1.61
36500 - Overhead Conductors, Device	Cond Alum Wp	1998	3,252	\$9,144.74	\$2.81	19,961,788	32,068,244.20	\$ 1.61
36500 - Overhead Conductors, Device	Cond Copper Bare	1998	1,978	\$8,719.73	\$4.41	19,963,766	32,076,963.93	\$ 1.61
36500 - Overhead Conductors, Device	Cond Copper Wp	1998	160	\$568.17	\$3.55	19,963,926	32,077,532.10	\$ 1.61
36500 - Overhead Conductors, Device	Cond Acsr	1999	96,053	\$318,952.03	\$3.32	20,059,979	32,396,484.13	\$ 1.61
36500 - Overhead Conductors, Device	Insulator	1999	4,690	\$316,547.27	\$67.49	20,064,669	32,713,031.40	\$ 1.63
36500 - Overhead Conductors, Device	Cond Triplex	1999	39,752	\$100,653.72	\$2.53	20,104,421	32,813,685.12	\$ 1.63
36500 - Overhead Conductors, Device	Cond All Alum	1999	12,320	\$78,803.25	\$6.40	20,116,741	32,892,488.37	\$ 1.64
36500 - Overhead Conductors, Device	Cond Duplex	1999	69,645	\$77,311.91	\$1.11	20,186,386	32,969,800.28	\$ 1.63
36500 - Overhead Conductors, Device	Cond Quadruplex	1999	12,874	\$49,133.74	\$3.82	20,199,260	33,018,934.02	\$ 1.63
36500 - Overhead Conductors, Device	Cond Alum Wp	1999	4,191	\$11,237.77	\$2.68	20,203,451	33,030,171.79	\$ 1.63
36500 - Overhead Conductors, Device	Cond Copper Bare	1999	194	\$1,995.38	\$10.29	20,203,645	33,032,167.17	\$ 1.63
36500 - Overhead Conductors, Device	Cond Copper Wp	1999	45	\$130.45	\$2.90	20,203,690	33,032,297.62	\$ 1.63
36500 - Overhead Conductors, Device	Insulator	2000	5,405	\$393,292.90	\$72.76	20,209,095	33,425,590.52	\$ 1.65
36500 - Overhead Conductors, Device	Cond Acsr	2000	81,147	\$288,115.80	\$3.55	20,290,242	33,713,706.32	\$ 1.66
36500 - Overhead Conductors, Device	Cond Triplex	2000	52,435	\$143,330.83	\$2.73	20,342,677	33,857,037.15	\$ 1.66
36500 - Overhead Conductors, Device	Cond Duplex	2000	65,096	\$77,495.69	\$1.19	20,407,773	33,934,532.84	\$ 1.66
36500 - Overhead Conductors, Device	Cond All Alum	2000	10,332	\$73,333.97	\$7.10	20,418,105	34,007,866.81	\$ 1.67
36500 - Overhead Conductors, Device	Cond Quadruplex	2000	11,045	\$42,269.25	\$3.83	20,429,150	34,050,136.06	\$ 1.67
36500 - Overhead Conductors, Device	Cond Alum Wp	2000	2,356	\$4,375.81	\$1.86	20,431,506	34,054,511.87	\$ 1.67
36500 - Overhead Conductors, Device	Cond Copper Bare	2000	25	\$800.50	\$32.02	20,431,531	34,055,312.37	\$ 1.67
36500 - Overhead Conductors, Device	Insulator	2001	4,693	\$313,250.71	\$66.75	20,436,224	34,368,563.08	\$ 1.68

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Acsr	2001	35,552	\$111,678.39	\$3.14	20,471,776	34,480,241.47	\$ 1.68
36500 - Overhead Conductors, Device	Cond Triplex	2001	28,652	\$73,343.32	\$2.56	20,500,428	34,553,584.79	\$ 1.69
36500 - Overhead Conductors, Device	Cond Duplex	2001	49,744	\$55,482.93	\$1.12	20,550,172	34,609,067.72	\$ 1.68
36500 - Overhead Conductors, Device	Cond Quadruplex	2001	7,728	\$21,978.06	\$2.84	20,557,900	34,631,045.78	\$ 1.68
36500 - Overhead Conductors, Device	Cond All Alum	2001	2,827	\$13,923.00	\$4.93	20,560,727	34,644,968.78	\$ 1.69
36500 - Overhead Conductors, Device	Cond Alum Wp	2001	603	\$729.52	\$1.21	20,561,330	34,645,698.30	\$ 1.68
36500 - Overhead Conductors, Device	Cond Copper Bare	2001	102	\$430.30	\$4.22	20,561,432	34,646,128.60	\$ 1.69
36500 - Overhead Conductors, Device	Cond Duplex 600 V	2001	30	\$28.60	\$0.95	20,561,462	34,646,157.20	\$ 1.69
36500 - Overhead Conductors, Device	Insulator	2002	6,742	\$467,755.06	\$69.38	20,568,204	35,113,912.26	\$ 1.71
36500 - Overhead Conductors, Device	Cond Acsr	2002	85,342	\$271,280.80	\$3.18	20,653,546	35,385,193.06	\$ 1.71
36500 - Overhead Conductors, Device	Cond Triplex	2002	53,025	\$159,705.03	\$3.01	20,706,571	35,544,898.09	\$ 1.72
36500 - Overhead Conductors, Device	Cond Duplex	2002	58,127	\$65,378.92	\$1.12	20,764,698	35,610,277.01	\$ 1.71
36500 - Overhead Conductors, Device	Cond All Alum	2002	9,777	\$62,660.31	\$6.41	20,774,475	35,672,937.32	\$ 1.72
36500 - Overhead Conductors, Device	Cond Quadruplex	2002	8,481	\$25,606.58	\$3.02	20,782,956	35,698,543.90	\$ 1.72
36500 - Overhead Conductors, Device	Cond Alum Wp	2002	2,512	\$3,215.15	\$1.28	20,785,468	35,701,759.05	\$ 1.72
36500 - Overhead Conductors, Device	Cond Copper Wp	2002	420	\$1,218.00	\$2.90	20,785,888	35,702,977.05	\$ 1.72
36500 - Overhead Conductors, Device	Cond Copper Bare	2002	265	\$822.43	\$3.10	20,786,153	35,703,799.48	\$ 1.72
36500 - Overhead Conductors, Device	Insulator	2003	4,458	\$362,500.31	\$81.31	20,790,611	36,066,299.79	\$ 1.73
36500 - Overhead Conductors, Device	Cond Acsr	2003	75,470	\$226,374.04	\$3.00	20,866,081	36,292,673.83	\$ 1.74
36500 - Overhead Conductors, Device	Cond Triplex	2003	29,969	\$92,725.86	\$3.09	20,896,050	36,385,399.69	\$ 1.74
36500 - Overhead Conductors, Device	Cond All Alum	2003	10,984	\$68,005.13	\$6.19	20,907,034	36,453,404.82	\$ 1.74
36500 - Overhead Conductors, Device	Cond Duplex	2003	31,035	\$39,994.23	\$1.29	20,938,069	36,493,399.05	\$ 1.74
36500 - Overhead Conductors, Device	Cond Quadruplex	2003	3,160	\$12,657.96	\$4.01	20,941,229	36,506,057.01	\$ 1.74
36500 - Overhead Conductors, Device	Cond Alum Wp	2003	1,354	\$2,046.25	\$1.51	20,942,583	36,508,103.26	\$ 1.74
36500 - Overhead Conductors, Device	Cond Copper Bare	2003	136	\$1,047.68	\$7.70	20,942,719	36,509,150.94	\$ 1.74
36500 - Overhead Conductors, Device	Insulator	2004	4,304	\$358,792.55	\$83.36	20,947,023	36,867,943.49	\$ 1.76
36500 - Overhead Conductors, Device	Cond Acsr	2004	50,621	\$157,130.79	\$3.10	20,997,644	37,025,074.28	\$ 1.76
36500 - Overhead Conductors, Device	Cond All Alum	2004	11,671	\$89,684.17	\$7.68	21,009,315	37,114,758.45	\$ 1.77
36500 - Overhead Conductors, Device	Cond Triplex	2004	31,753	\$85,904.93	\$2.71	21,041,068	37,200,663.38	\$ 1.77
36500 - Overhead Conductors, Device	Cond Duplex	2004	53,117	\$48,212.96	\$0.91	21,094,185	37,248,876.34	\$ 1.77
36500 - Overhead Conductors, Device	Cond Quadruplex	2004	5,681	\$24,910.55	\$4.38	21,099,866	37,273,786.89	\$ 1.77

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Alum Wp	2004	3,517	\$5,367.13	\$1.53	21,103,383	37,279,154.02	\$ 1.77
36500 - Overhead Conductors, Device	Cond Copper Bare	2004	394	\$825.68	\$2.10	21,103,777	37,279,979.70	\$ 1.77
36500 - Overhead Conductors, Device	Cond Copper Wp	2004	180	\$159.36	\$0.89	21,103,957	37,280,139.06	\$ 1.77
36500 - Overhead Conductors, Device	Insulator	2005	4,817	\$460,635.09	\$95.63	21,108,774	37,740,774.15	\$ 1.79
36500 - Overhead Conductors, Device	Cond Acsr	2005	64,895	\$212,592.29	\$3.28	21,173,669	37,953,366.44	\$ 1.79
36500 - Overhead Conductors, Device	Cond Triplex	2005	30,929	\$77,367.85	\$2.50	21,204,598	38,030,734.29	\$ 1.79
36500 - Overhead Conductors, Device	Cond Duplex	2005	48,754	\$50,209.38	\$1.03	21,253,352	38,080,943.67	\$ 1.79
36500 - Overhead Conductors, Device	Cond Quadruplex	2005	5,076	\$22,458.79	\$4.42	21,258,428	38,103,402.46	\$ 1.79
36500 - Overhead Conductors, Device	Cond All Alum	2005	1,322	\$10,010.71	\$7.57	21,259,750	38,113,413.17	\$ 1.79
36500 - Overhead Conductors, Device	Cond Alum Wp	2005	310	\$807.50	\$2.60	21,260,060	38,114,220.67	\$ 1.79
36500 - Overhead Conductors, Device	Cond Copper Bare	2005	199	\$231.70	\$1.16	21,260,259	38,114,452.37	\$ 1.79
36500 - Overhead Conductors, Device	Cond Acsr	2006	114,692	\$435,426.53	\$3.80	21,374,951	38,549,878.90	\$ 1.80
36500 - Overhead Conductors, Device	Insulator	2006	4,046	\$268,717.36	\$66.42	21,378,997	38,818,596.26	\$ 1.82
36500 - Overhead Conductors, Device	Cond Triplex	2006	32,913	\$65,917.09	\$2.00	21,411,910	38,884,513.35	\$ 1.82
36500 - Overhead Conductors, Device	Cond Duplex	2006	54,118	\$48,885.95	\$0.90	21,466,028	38,933,399.30	\$ 1.81
36500 - Overhead Conductors, Device	Cond Quadruplex	2006	6,266	\$31,630.28	\$5.05	21,472,294	38,965,029.58	\$ 1.81
36500 - Overhead Conductors, Device	Cond All Alum	2006	2,454	\$14,311.15	\$5.83	21,474,748	38,979,340.73	\$ 1.82
36500 - Overhead Conductors, Device	Cond Copper Bare	2006	1,744	\$6,494.18	\$3.72	21,476,492	38,985,834.91	\$ 1.82
36500 - Overhead Conductors, Device	Cond Alum Wp	2006	919	\$2,866.43	\$3.12	21,477,411	38,988,701.34	\$ 1.82
36500 - Overhead Conductors, Device	Cond Copper Wp	2006	1,852	\$1,651.98	\$0.89	21,479,263	38,990,353.32	\$ 1.82
36500 - Overhead Conductors, Device	Cond Duplex 600 V	2006	795	\$751.39	\$0.95	21,480,058	38,991,104.71	\$ 1.82
36500 - Overhead Conductors, Device	Cond Acsr	2007	68,494	\$329,630.20	\$4.81	21,548,552	39,320,734.91	\$ 1.82
36500 - Overhead Conductors, Device	Insulator	2007	4,889	\$250,634.70	\$51.27	21,553,441	39,571,369.61	\$ 1.84
36500 - Overhead Conductors, Device	Cond All Alum	2007	8,318	\$51,741.12	\$6.22	21,561,759	39,623,110.73	\$ 1.84
36500 - Overhead Conductors, Device	Cond Triplex	2007	24,895	\$50,177.54	\$2.02	21,586,654	39,673,288.27	\$ 1.84
36500 - Overhead Conductors, Device	Cond Duplex	2007	50,574	\$36,341.33	\$0.72	21,637,228	39,709,629.60	\$ 1.84
36500 - Overhead Conductors, Device	Cond Quadruplex	2007	3,489	\$14,385.78	\$4.12	21,640,717	39,724,015.38	\$ 1.84
36500 - Overhead Conductors, Device	Cond Copper Bare	2007	805	\$8,663.03	\$10.76	21,641,522	39,732,678.41	\$ 1.84
36500 - Overhead Conductors, Device	Cond Alum Wp	2007	427	\$2,705.18	\$6.34	21,641,949	39,735,383.59	\$ 1.84
36500 - Overhead Conductors, Device	Cond Duplex 600 V	2007	1,314	\$1,205.74	\$0.92	21,643,263	39,736,589.33	\$ 1.84
36500 - Overhead Conductors, Device	Cond Acsr	2008	62,546	\$240,992.96	\$3.85	21,705,809	39,977,582.29	\$ 1.84

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Insulator	2008	5,293	\$157,034.21	\$29.67	21,711,102	40,134,616.50	\$ 1.85
36500 - Overhead Conductors, Device	Cond All Alum	2008	14,363	\$108,260.65	\$7.54	21,725,465	40,242,877.15	\$ 1.85
36500 - Overhead Conductors, Device	Cond Triplex	2008	31,142	\$60,595.39	\$1.95	21,756,607	40,303,472.54	\$ 1.85
36500 - Overhead Conductors, Device	Cond Duplex	2008	36,402	\$25,754.71	\$0.71	21,793,009	40,329,227.25	\$ 1.85
36500 - Overhead Conductors, Device	Cond Quadruplex	2008	5,981	\$21,799.23	\$3.64	21,798,990	40,351,026.48	\$ 1.85
36500 - Overhead Conductors, Device	Cond Copper Bare	2008	1,405	\$15,480.86	\$11.02	21,800,395	40,366,507.34	\$ 1.85
36500 - Overhead Conductors, Device	Cond Alum Wp	2008	134	\$255.59	\$1.91	21,800,529	40,366,762.93	\$ 1.85
36500 - Overhead Conductors, Device	Cond Duplex 600 V	2008	160	\$138.39	\$0.86	21,800,689	40,366,901.32	\$ 1.85
36500 - Overhead Conductors, Device	Cond Acsr	2009	41,027	\$213,765.71	\$5.21	21,841,716	40,580,667.03	\$ 1.86
36500 - Overhead Conductors, Device	Insulator	2009	3,940	\$213,692.14	\$54.24	21,845,656	40,794,359.17	\$ 1.87
36500 - Overhead Conductors, Device	Cond Triplex	2009	21,440	\$45,436.99	\$2.12	21,867,096	40,839,796.16	\$ 1.87
36500 - Overhead Conductors, Device	Cond Quadruplex	2009	5,504	\$31,092.84	\$5.65	21,872,600	40,870,889.00	\$ 1.87
36500 - Overhead Conductors, Device	Cond All Alum	2009	7,343	\$28,309.75	\$3.86	21,879,943	40,899,198.75	\$ 1.87
36500 - Overhead Conductors, Device	Cond Duplex	2009	39,844	\$24,848.16	\$0.62	21,919,787	40,924,046.91	\$ 1.87
36500 - Overhead Conductors, Device	Cond Copper Bare	2009	1,499	\$8,722.48	\$5.82	21,921,286	40,932,769.39	\$ 1.87
36500 - Overhead Conductors, Device	Cond Alum Wp	2009	400	\$954.37	\$2.39	21,921,686	40,933,723.76	\$ 1.87
36500 - Overhead Conductors, Device	Cond Duplex 600 V	2009	200	\$125.13	\$0.63	21,921,886	40,933,848.89	\$ 1.87
36500 - Overhead Conductors, Device	Cond Acsr	2010	72,886	\$434,480.34	\$5.96	21,994,772	41,368,329.23	\$ 1.88
36500 - Overhead Conductors, Device	Insulator	2010	5,664	\$247,700.37	\$43.73	22,000,436	41,616,029.60	\$ 1.89
36500 - Overhead Conductors, Device	Cond Triplex	2010	32,284	\$64,597.44	\$2.00	22,032,720	41,680,627.04	\$ 1.89
36500 - Overhead Conductors, Device	Cond All Alum	2010	8,444	\$55,944.32	\$6.63	22,041,164	41,736,571.36	\$ 1.89
36500 - Overhead Conductors, Device	Cond Quadruplex	2010	4,679	\$23,651.26	\$5.05	22,045,843	41,760,222.62	\$ 1.89
36500 - Overhead Conductors, Device	Cond Duplex	2010	24,172	\$18,854.16	\$0.78	22,070,015	41,779,076.78	\$ 1.89
36500 - Overhead Conductors, Device	Cond Copper Bare	2010	915	\$7,830.23	\$8.56	22,070,930	41,786,907.01	\$ 1.89
36500 - Overhead Conductors, Device	Cond Alum Wp	2010	140	\$371.13	\$2.65	22,071,070	41,787,278.14	\$ 1.89
36500 - Overhead Conductors, Device	Cond Duplex 600 V	2010	115	\$245.31	\$2.13	22,071,185	41,787,523.45	\$ 1.89
36500 - Overhead Conductors, Device	Insulator	2011	6,058	\$274,499.34	\$45.31	22,077,243	42,062,022.79	\$ 1.91
36500 - Overhead Conductors, Device	Cond Acsr	2011	49,707	\$261,930.21	\$5.27	22,126,950	42,323,953.00	\$ 1.91
36500 - Overhead Conductors, Device	Cond Triplex	2011	33,344	\$81,361.65	\$2.44	22,160,294	42,405,314.65	\$ 1.91
36500 - Overhead Conductors, Device	Cond All Alum	2011	6,258	\$65,924.59	\$10.53	22,166,552	42,471,239.24	\$ 1.92
36500 - Overhead Conductors, Device	Cond Duplex	2011	45,579	\$35,754.18	\$0.78	22,212,131	42,506,993.42	\$ 1.91

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Quadruplex	2011	5,358	\$30,042.79	\$5.61	22,217,489	42,537,036.21	\$ 1.91
36500 - Overhead Conductors, Device	Cond Copper Bare	2011	933	\$11,343.14	\$12.16	22,218,422	42,548,379.35	\$ 1.92
36500 - Overhead Conductors, Device	Cond Alum Wp	2011	1,165	\$3,981.18	\$3.42	22,219,587	42,552,360.53	\$ 1.92
36500 - Overhead Conductors, Device	Cond Duplex 600 V	2011	375	\$436.63	\$1.16	22,219,962	42,552,797.16	\$ 1.92
36500 - Overhead Conductors, Device	Cond Acsr	2012	128,756	\$741,786.79	\$5.76	22,348,718	43,294,583.95	\$ 1.94
36500 - Overhead Conductors, Device	Insulator	2012	5,903	\$231,813.02	\$39.27	22,354,621	43,526,396.97	\$ 1.95
36500 - Overhead Conductors, Device	Cond Triplex	2012	38,225	\$111,736.43	\$2.92	22,392,846	43,638,133.40	\$ 1.95
36500 - Overhead Conductors, Device	Cond Duplex	2012	39,784	\$40,630.99	\$1.02	22,432,630	43,678,764.39	\$ 1.95
36500 - Overhead Conductors, Device	Cond Quadruplex	2012	4,639	\$24,088.59	\$5.19	22,437,269	43,702,852.98	\$ 1.95
36500 - Overhead Conductors, Device	Cond All Alum	2012	1,531	\$20,672.20	\$13.50	22,438,800	43,723,525.18	\$ 1.95
36500 - Overhead Conductors, Device	Cond Copper Bare	2012	767	\$11,215.43	\$14.62	22,439,567	43,734,740.61	\$ 1.95
36500 - Overhead Conductors, Device	Cond Duplex 600 V	2012	764	\$761.32	\$1.00	22,440,331	43,735,501.93	\$ 1.95
36500 - Overhead Conductors, Device	Cond Alum Wp	2012	70	\$188.63	\$2.69	22,440,401	43,735,690.56	\$ 1.95
36500 - Overhead Conductors, Device	Cond Acsr	2013	68,460	\$392,817.18	\$5.74	22,508,861	44,128,507.74	\$ 1.96
36500 - Overhead Conductors, Device	Insulator	2013	4,968	\$275,037.46	\$55.36	22,513,829	44,403,545.20	\$ 1.97
36500 - Overhead Conductors, Device	Cond All Alum	2013	25,714	\$252,905.77	\$9.84	22,539,543	44,656,450.97	\$ 1.98
36500 - Overhead Conductors, Device	Cond Triplex	2013	30,111	\$72,261.43	\$2.40	22,569,654	44,728,712.40	\$ 1.98
36500 - Overhead Conductors, Device	Cond Duplex	2013	28,027	\$31,066.80	\$1.11	22,597,681	44,759,779.20	\$ 1.98
36500 - Overhead Conductors, Device	Cond Quadruplex	2013	3,972	\$15,474.04	\$3.90	22,601,653	44,775,253.24	\$ 1.98
36500 - Overhead Conductors, Device	Cond Copper Bare	2013	765	\$10,302.80	\$13.47	22,602,418	44,785,556.04	\$ 1.98
36500 - Overhead Conductors, Device	Cond Acsr	2014	61,990	\$368,453.58	\$5.94	22,664,408	45,154,009.62	\$ 1.99
36500 - Overhead Conductors, Device	Insulator	2014	4,758	\$216,458.71	\$45.49	22,669,166	45,370,468.33	\$ 2.00
36500 - Overhead Conductors, Device	Cond All Alum	2014	9,926	\$80,671.03	\$8.13	22,679,092	45,451,139.36	\$ 2.00
36500 - Overhead Conductors, Device	Cond Triplex	2014	20,408	\$58,814.93	\$2.88	22,699,500	45,509,954.29	\$ 2.00
36500 - Overhead Conductors, Device	Cond Quadruplex	2014	5,956	\$26,786.11	\$4.50	22,705,456	45,536,740.40	\$ 2.01
36500 - Overhead Conductors, Device	Cond Duplex	2014	25,642	\$24,462.16	\$0.95	22,731,098	45,561,202.56	\$ 2.00
36500 - Overhead Conductors, Device	Cond Copper Bare	2014	1,215	\$18,292.08	\$15.06	22,732,313	45,579,494.64	\$ 2.01
36500 - Overhead Conductors, Device	Cond Copper Wp	2014	50	\$653.14	\$13.06	22,732,363	45,580,147.78	\$ 2.01
36500 - Overhead Conductors, Device	Insulator	2015	691	\$46,037.57	\$66.62	22,733,054	45,626,185.35	\$ 2.01
36500 - Overhead Conductors, Device	Cond Acsr	2015	5,397	\$36,497.32	\$6.76	22,738,451	45,662,682.67	\$ 2.01
36500 - Overhead Conductors, Device	Cond Triplex	2015	7,759	\$26,822.45	\$3.46	22,746,210	45,689,505.12	\$ 2.01

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36500 - Overhead Conductors, Device	Cond Duplex	2015	9,731	\$13,497.96	\$1.39	22,755,941	45,703,003.08	\$ 2.01
36500 - Overhead Conductors, Device	Cond Quadruplex	2015	1,630	\$9,051.38	\$5.55	22,757,571	45,712,054.46	\$ 2.01
			22,757,571	\$ 45,712,054.46	\$ 2.01			
	Cond Acsr		8,789,318	\$ 16,169,240.14	\$ 1.84			
	Insulator		402,001	10,999,895.56	\$ 27.36			
	Cond Triplex		3,885,522	7,618,858.86	\$ 1.96			
	Cond Duplex		3,293,282	3,170,070.00	\$ 0.96			
	Cond All Alum		896,714	2,470,309.31	\$ 2.75			
	Cond Alum Wp		1,733,840	2,401,187.29	\$ 1.38			
	Cond Quadruplex		431,381	1,474,003.52	\$ 3.42			
	Cond Copper Wp		2,162,499	819,132.22	\$ 0.38			
	Cond Copper Bare		834,085	525,689.39	\$ 0.63			
	Cond Iron		325,176	59,975.66	\$ 0.18			
	Cond Duplex 600 V		3,753	3,692.51	\$ 0.98			
			22,757,571	\$ 45,712,054.46	\$ 2.01			
			-	\$ -				
		1921	346	\$ 44.00	\$ 0.13	346	\$ 44.00	\$ 0.13
		1922	112	12.46	\$ 0.11	458	56.46	\$ 0.12
		1923	528	61.78	\$ 0.12	986	118.24	\$ 0.12
		1924	10,172	1,164.69	\$ 0.11	11,158	1,282.93	\$ 0.11
		1925	16,102	1,929.96	\$ 0.12	27,260	3,212.89	\$ 0.12
		1926	35,390	4,011.66	\$ 0.11	62,650	7,224.55	\$ 0.12
		1927	91,033	10,293.16	\$ 0.11	153,683	17,517.71	\$ 0.11
		1928	122,491	14,240.55	\$ 0.12	276,174	31,758.26	\$ 0.11
		1929	92,361	11,619.90	\$ 0.13	368,535	43,378.16	\$ 0.12
		1930	87,516	9,685.29	\$ 0.11	456,051	53,063.45	\$ 0.12
		1931	103,245	10,008.33	\$ 0.10	559,296	63,071.78	\$ 0.11
		1932	40,167	5,671.55	\$ 0.14	599,463	68,743.33	\$ 0.11
		1933	11,878	1,231.76	\$ 0.10	611,341	69,975.09	\$ 0.11

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
		1934	21,941	2,710.12	\$ 0.12	633,282	72,685.21	\$ 0.11
		1935	28,864	3,146.82	\$ 0.11	662,146	75,832.03	\$ 0.11
		1936	50,056	6,966.09	\$ 0.14	712,202	82,798.12	\$ 0.12
		1937	80,721	13,962.58	\$ 0.17	792,923	96,760.70	\$ 0.12
		1938	74,489	9,080.90	\$ 0.12	867,412	105,841.60	\$ 0.12
		1939	55,222	6,772.68	\$ 0.12	922,634	112,614.28	\$ 0.12
		1940	18,521	2,073.95	\$ 0.11	941,155	114,688.23	\$ 0.12
		1941	67,967	8,368.71	\$ 0.12	1,009,122	123,056.94	\$ 0.12
		1942	22,746	2,568.22	\$ 0.11	1,031,868	125,625.16	\$ 0.12
		1943	505	42.34	\$ 0.08	1,032,373	125,667.50	\$ 0.12
		1944	19,341	2,219.84	\$ 0.11	1,051,714	127,887.34	\$ 0.12
		1945	57,562	7,131.73	\$ 0.12	1,109,276	135,019.07	\$ 0.12
		1946	55,100	9,014.34	\$ 0.16	1,164,376	144,033.41	\$ 0.12
		1947	48,212	10,643.77	\$ 0.22	1,212,588	154,677.18	\$ 0.13
		1948	161,704	38,372.35	\$ 0.24	1,374,292	193,049.53	\$ 0.14
		1949	251,983	72,193.96	\$ 0.29	1,626,275	265,243.49	\$ 0.16
		1950	114,831	24,274.61	\$ 0.21	1,741,106	289,518.10	\$ 0.17
		1951	99,908	57,453.78	\$ 0.58	1,841,014	346,971.88	\$ 0.19
		1952	100,238	58,489.79	\$ 0.58	1,941,252	405,461.67	\$ 0.21
		1953	210,000	113,937.74	\$ 0.54	2,151,252	519,399.41	\$ 0.24
		1954	84,761	41,786.41	\$ 0.49	2,236,013	561,185.82	\$ 0.25
		1955	125,770	86,289.56	\$ 0.69	2,361,783	647,475.38	\$ 0.27
		1956	296,556	117,181.85	\$ 0.40	2,658,339	764,657.23	\$ 0.29
		1957	298,708	148,579.51	\$ 0.50	2,957,047	913,236.74	\$ 0.31
		1958	316,325	164,018.09	\$ 0.52	3,273,372	1,077,254.83	\$ 0.33
		1959	343,328	191,411.22	\$ 0.56	3,616,700	1,268,666.05	\$ 0.35
		1960	478,176	256,356.17	\$ 0.54	4,094,876	1,525,022.22	\$ 0.37
		1961	355,742	205,214.92	\$ 0.58	4,450,618	1,730,237.14	\$ 0.39
		1962	391,169	265,614.41	\$ 0.68	4,841,787	1,995,851.55	\$ 0.41
		1963	364,817	246,677.76	\$ 0.68	5,206,604	2,242,529.31	\$ 0.43
		1964	453,759	347,314.89	\$ 0.77	5,660,363	2,589,844.20	\$ 0.46

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
		1965	385,577	327,403.00	\$ 0.85	6,045,940	2,917,247.20	\$ 0.48
		1966	443,930	388,527.13	\$ 0.88	6,489,870	3,305,774.33	\$ 0.51
		1967	463,199	419,047.23	\$ 0.90	6,953,069	3,724,821.56	\$ 0.54
		1968	514,827	418,864.08	\$ 0.81	7,467,896	4,143,685.64	\$ 0.55
		1969	565,259	510,325.78	\$ 0.90	8,033,155	4,654,011.42	\$ 0.58
		1970	594,856	511,468.49	\$ 0.86	8,628,011	5,165,479.91	\$ 0.60
		1971	584,943	544,540.00	\$ 0.93	9,212,954	5,710,019.91	\$ 0.62
		1972	639,192	566,243.41	\$ 0.89	9,852,146	6,276,263.32	\$ 0.64
		1973	539,404	502,429.50	\$ 0.93	10,391,550	6,778,692.82	\$ 0.65
		1974	505,695	376,282.85	\$ 0.74	10,897,245	7,154,975.67	\$ 0.66
		1975	402,046	491,708.92	\$ 1.22	11,299,291	7,646,684.59	\$ 0.68
		1976	508,253	651,275.77	\$ 1.28	11,807,544	8,297,960.36	\$ 0.70
		1977	599,776	696,853.85	\$ 1.16	12,407,320	8,994,814.21	\$ 0.72
		1978	374,421	539,738.68	\$ 1.44	12,781,741	9,534,552.89	\$ 0.75
		1979	466,520	772,251.22	\$ 1.66	13,248,261	10,306,804.11	\$ 0.78
		1980	493,929	889,220.46	\$ 1.80	13,742,190	11,196,024.57	\$ 0.81
		1981	437,170	953,151.91	\$ 2.18	14,179,360	12,149,176.48	\$ 0.86
		1982	531,595	1,475,988.62	\$ 2.78	14,710,955	13,625,165.10	\$ 0.93
		1983	350,055	855,500.23	\$ 2.44	15,061,010	14,480,665.33	\$ 0.96
		1984	400,488	1,066,610.08	\$ 2.66	15,461,498	15,547,275.41	\$ 1.01
		1985	531,010	1,598,744.76	\$ 3.01	15,992,508	17,146,020.17	\$ 1.07
		1986	318,467	1,001,079.24	\$ 3.14	16,310,975	18,147,099.41	\$ 1.11
		1987	413,690	1,216,718.51	\$ 2.94	16,724,665	19,363,817.92	\$ 1.16
		1988	295,968	1,149,461.22	\$ 3.88	17,020,633	20,513,279.14	\$ 1.21
		1989	302,649	1,101,542.29	\$ 3.64	17,323,282	21,614,821.43	\$ 1.25
		1990	291,485	1,122,745.28	\$ 3.85	17,614,767	22,737,566.71	\$ 1.29
		1991	322,932	1,078,542.56	\$ 3.34	17,937,699	23,816,109.27	\$ 1.33
		1992	304,671	1,121,880.94	\$ 3.68	18,242,370	24,937,990.21	\$ 1.37
		1993	342,520	1,360,369.80	\$ 3.97	18,584,890	26,298,360.01	\$ 1.42
		1994	263,238	1,099,185.21	\$ 4.18	18,848,128	27,397,545.22	\$ 1.45
		1995	329,755	1,298,079.14	\$ 3.94	19,177,883	28,695,624.36	\$ 1.50

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
		1996	245,197	1,144,662.04	\$ 4.67	19,423,080	29,840,286.40	\$ 1.54
		1997	317,652	1,360,648.29	\$ 4.28	19,740,732	31,200,934.69	\$ 1.58
		1998	223,194	876,597.41	\$ 3.93	19,963,926	32,077,532.10	\$ 1.61
		1999	239,764	954,765.52	\$ 3.98	20,203,690	33,032,297.62	\$ 1.63
		2000	227,841	1,023,014.75	\$ 4.49	20,431,531	34,055,312.37	\$ 1.67
		2001	129,931	590,844.83	\$ 4.55	20,561,462	34,646,157.20	\$ 1.69
		2002	224,691	1,057,642.28	\$ 4.71	20,786,153	35,703,799.48	\$ 1.72
		2003	156,566	805,351.46	\$ 5.14	20,942,719	36,509,150.94	\$ 1.74
		2004	161,238	770,988.12	\$ 4.78	21,103,957	37,280,139.06	\$ 1.77
		2005	156,302	834,313.31	\$ 5.34	21,260,259	38,114,452.37	\$ 1.79
		2006	219,799	876,652.34	\$ 3.99	21,480,058	38,991,104.71	\$ 1.82
		2007	163,205	745,484.62	\$ 4.57	21,643,263	39,736,589.33	\$ 1.84
		2008	157,426	630,311.99	\$ 4.00	21,800,689	40,366,901.32	\$ 1.85
		2009	121,197	566,947.57	\$ 4.68	21,921,886	40,933,848.89	\$ 1.87
		2010	149,299	853,674.56	\$ 5.72	22,071,185	41,787,523.45	\$ 1.89
		2011	148,777	765,273.71	\$ 5.14	22,219,962	42,552,797.16	\$ 1.92
		2012	220,439	1,182,893.40	\$ 5.37	22,440,401	43,735,690.56	\$ 1.95
		2013	162,017	1,049,865.48	\$ 6.48	22,602,418	44,785,556.04	\$ 1.98
		2014	129,945	794,591.74	\$ 6.11	22,732,363	45,580,147.78	\$ 2.01
		2015	25,208	131,906.68	\$ 5.23	22,757,571	45,712,054.46	\$ 2.01
			22,757,571	\$ 45,712,054.46	\$ 2.01			
			-	\$ -				

midpoint 11,378,786 \$ 22,856,027.23 \$ 1.00

39	Average Physical Age of Overhead Conductor and Insulators
24	Weighted Cost Average Age of Overhead Conductor and Insulators
31	Age of Average Cost of Overhead Conductor and Insulators

Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 365 Conductor & Insulator Vintage Count & Cost

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36700 - Undergrnd Conductors,Device	Cond Copper Bare	1961	1,008	\$615.55	\$0.61	1,008	\$ 615.55	\$ 0.61
36700 - Undergrnd Conductors,Device	Cond Copper Bare	1964	960	\$347.40	\$0.36	1,968	962.95	\$ 0.49
36700 - Undergrnd Conductors,Device	Cond Copper Bare	1965	1,093	\$560.68	\$0.51	3,061	1,523.63	\$ 0.50
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1968	3,187	\$872.04	\$0.27	6,248	2,395.67	\$ 0.38
36700 - Undergrnd Conductors,Device	Cond Copper Bare	1968	283	\$773.31	\$2.73	6,531	3,168.98	\$ 0.49
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1969	14,911	\$7,524.37	\$0.50	21,442	10,693.35	\$ 0.50
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1970	10,021	\$2,864.17	\$0.29	31,463	13,557.52	\$ 0.43
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1971	14,517	\$13,701.04	\$0.94	45,980	27,258.56	\$ 0.59
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1971	16,810	\$4,423.56	\$0.26	62,790	31,682.12	\$ 0.50
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1972	54,709	\$46,267.75	\$0.85	117,499	77,949.87	\$ 0.66
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1972	7,196	\$4,148.75	\$0.58	124,695	82,098.62	\$ 0.66
36700 - Undergrnd Conductors,Device	Cond Quadruplex 600 V	1972	52	\$60.84	\$1.17	124,747	82,159.46	\$ 0.66
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1973	102,025	\$74,151.06	\$0.73	226,772	156,310.52	\$ 0.69
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1973	16,370	\$10,499.53	\$0.64	243,142	166,810.05	\$ 0.69
36700 - Undergrnd Conductors,Device	Cond Quadruplex 600 V	1973	8	\$3.78	\$0.47	243,150	166,813.83	\$ 0.69
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1974	92,087	\$82,648.87	\$0.90	335,237	249,462.70	\$ 0.74
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1974	36,963	\$17,820.06	\$0.48	372,200	267,282.76	\$ 0.72
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1974	25,832	\$13,649.08	\$0.53	398,032	280,931.84	\$ 0.71
36700 - Undergrnd Conductors,Device	Cond Alum	1975	131,828	\$189,742.47	\$1.44	529,860	470,674.31	\$ 0.89
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1975	91,132	\$101,291.04	\$1.11	620,992	571,965.35	\$ 0.92
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1975	53,567	\$36,754.09	\$0.69	674,559	608,719.44	\$ 0.90
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1975	13,363	\$11,905.47	\$0.89	687,922	620,624.91	\$ 0.90
36700 - Undergrnd Conductors,Device	Cond Alum	1976	331,714	\$451,349.24	\$1.36	1,019,636	1,071,974.15	\$ 1.05
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1976	107,112	\$119,446.77	\$1.12	1,126,748	1,191,420.92	\$ 1.06
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1976	71,846	\$47,233.39	\$0.66	1,198,594	1,238,654.31	\$ 1.03
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1976	27,539	\$22,268.07	\$0.81	1,226,133	1,260,922.38	\$ 1.03
36700 - Undergrnd Conductors,Device	Cond Alum	1977	526,072	\$846,984.16	\$1.61	1,752,205	2,107,906.54	\$ 1.20
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1977	136,475	\$155,906.03	\$1.14	1,888,680	2,263,812.57	\$ 1.20
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1977	76,712	\$58,830.02	\$0.77	1,965,392	2,322,642.59	\$ 1.18
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1977	46,335	\$44,282.26	\$0.96	2,011,727	2,366,924.85	\$ 1.18
36700 - Undergrnd Conductors,Device	Cond Alum	1978	458,053	\$840,045.01	\$1.83	2,469,780	3,206,969.86	\$ 1.30

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1978	118,000	\$178,600.07	\$1.51	2,587,780	3,385,569.93	\$ 1.31
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1978	77,839	\$72,552.77	\$0.93	2,665,619	3,458,122.70	\$ 1.30
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1978	26,437	\$31,028.92	\$1.17	2,692,056	3,489,151.62	\$ 1.30
36700 - Undergrnd Conductors,Device	Cond Alum	1979	790,953	\$1,306,594.26	\$1.65	3,483,009	4,795,745.88	\$ 1.38
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1979	114,414	\$221,561.81	\$1.94	3,597,423	5,017,307.69	\$ 1.39
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1979	74,671	\$94,463.87	\$1.27	3,672,094	5,111,771.56	\$ 1.39
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1979	13,898	\$22,967.39	\$1.65	3,685,992	5,134,738.95	\$ 1.39
36700 - Undergrnd Conductors,Device	Cond Alum	1980	683,200	\$1,338,649.05	\$1.96	4,369,192	6,473,388.00	\$ 1.48
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1980	81,798	\$195,023.72	\$2.38	4,450,990	6,668,411.72	\$ 1.50
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1980	64,098	\$95,831.37	\$1.50	4,515,088	6,764,243.09	\$ 1.50
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1980	20,050	\$32,818.27	\$1.64	4,535,138	6,797,061.36	\$ 1.50
36700 - Undergrnd Conductors,Device	Cond Triplex 15 Kv	1980	620	\$2,965.33	\$4.78	4,535,758	6,800,026.69	\$ 1.50
36700 - Undergrnd Conductors,Device	Cond Alum	1981	749,979	\$1,307,726.37	\$1.74	5,285,737	8,107,753.06	\$ 1.53
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1981	75,616	\$191,133.68	\$2.53	5,361,353	8,298,886.74	\$ 1.55
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1981	56,723	\$83,815.12	\$1.48	5,418,076	8,382,701.86	\$ 1.55
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1981	24,528	\$38,839.88	\$1.58	5,442,604	8,421,541.74	\$ 1.55
36700 - Undergrnd Conductors,Device	Cond Triplex 15 Kv	1981	396	\$1,725.10	\$4.36	5,443,000	8,423,266.84	\$ 1.55
36700 - Undergrnd Conductors,Device	Cond Alum	1982	443,170	\$1,225,419.74	\$2.77	5,886,170	9,648,686.58	\$ 1.64
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1982	54,011	\$162,574.65	\$3.01	5,940,181	9,811,261.23	\$ 1.65
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1982	36,811	\$66,499.57	\$1.81	5,976,992	9,877,760.80	\$ 1.65
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1982	18,622	\$32,301.96	\$1.73	5,995,614	9,910,062.76	\$ 1.65
36700 - Undergrnd Conductors,Device	Cond Alum	1983	355,328	\$871,553.54	\$2.45	6,350,942	10,781,616.30	\$ 1.70
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1983	44,098	\$133,403.41	\$3.03	6,395,040	10,915,019.71	\$ 1.71
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1983	39,379	\$65,930.03	\$1.67	6,434,419	10,980,949.74	\$ 1.71
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1983	7,832	\$17,607.98	\$2.25	6,442,251	10,998,557.72	\$ 1.71
36700 - Undergrnd Conductors,Device	Cond Alum	1984	252,485	\$529,719.68	\$2.10	6,694,736	11,528,277.40	\$ 1.72
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1984	42,733	\$110,283.80	\$2.58	6,737,469	11,638,561.20	\$ 1.73
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1984	41,768	\$78,860.24	\$1.89	6,779,237	11,717,421.44	\$ 1.73
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1984	10,825	\$29,782.80	\$2.75	6,790,062	11,747,204.24	\$ 1.73
36700 - Undergrnd Conductors,Device	Cond Triplex	1984	120	\$799.74	\$6.66	6,790,182	11,748,003.98	\$ 1.73
36700 - Undergrnd Conductors,Device	Cond Duplex	1984	40	\$22.40	\$0.56	6,790,222	11,748,026.38	\$ 1.73

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36700 - Undergrnd Conductors,Device	Cond Alum	1985	404,452	\$1,033,085.71	\$2.55	7,194,674	12,781,112.09	\$ 1.78
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1985	39,221	\$114,913.88	\$2.93	7,233,895	12,896,025.97	\$ 1.78
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1985	31,164	\$57,882.36	\$1.86	7,265,059	12,953,908.33	\$ 1.78
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1985	23,286	\$46,891.00	\$2.01	7,288,345	13,000,799.33	\$ 1.78
36700 - Undergrnd Conductors,Device	Cond Triplex 15 Kv	1985	781	\$5,783.63	\$7.41	7,289,126	13,006,582.96	\$ 1.78
36700 - Undergrnd Conductors,Device	Cond Alum	1986	151,045	\$401,477.69	\$2.66	7,440,171	13,408,060.65	\$ 1.80
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1986	33,148	\$94,522.46	\$2.85	7,473,319	13,502,583.11	\$ 1.81
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1986	34,062	\$61,134.00	\$1.79	7,507,381	13,563,717.11	\$ 1.81
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1986	9,769	\$23,001.92	\$2.35	7,517,150	13,586,719.03	\$ 1.81
36700 - Undergrnd Conductors,Device	Cond Alum	1987	329,735	\$690,222.35	\$2.09	7,846,885	14,276,941.38	\$ 1.82
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1987	47,392	\$127,773.69	\$2.70	7,894,277	14,404,715.07	\$ 1.82
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1987	33,195	\$59,181.17	\$1.78	7,927,472	14,463,896.24	\$ 1.82
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1987	11,122	\$26,126.53	\$2.35	7,938,594	14,490,022.77	\$ 1.83
36700 - Undergrnd Conductors,Device	Cond Alum	1988	177,790	\$508,651.91	\$2.86	8,116,384	14,998,674.68	\$ 1.85
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1988	31,640	\$122,415.64	\$3.87	8,148,024	15,121,090.32	\$ 1.86
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1988	31,291	\$51,074.98	\$1.63	8,179,315	15,172,165.30	\$ 1.85
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1988	8,273	\$21,270.30	\$2.57	8,187,588	15,193,435.60	\$ 1.86
36700 - Undergrnd Conductors,Device	Cond Alum	1989	139,384	\$448,834.85	\$3.22	8,326,972	15,642,270.45	\$ 1.88
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1989	26,286	\$99,006.08	\$3.77	8,353,258	15,741,276.53	\$ 1.88
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1989	39,385	\$67,379.91	\$1.71	8,392,643	15,808,656.44	\$ 1.88
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1989	11,001	\$35,075.51	\$3.19	8,403,644	15,843,731.95	\$ 1.89
36700 - Undergrnd Conductors,Device	Cond Alum	1990	210,163	\$674,241.40	\$3.21	8,613,807	16,517,973.35	\$ 1.92
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1990	27,974	\$118,629.41	\$4.24	8,641,781	16,636,602.76	\$ 1.93
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1990	26,817	\$53,395.89	\$1.99	8,668,598	16,689,998.65	\$ 1.93
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1990	9,749	\$39,617.13	\$4.06	8,678,347	16,729,615.78	\$ 1.93
36700 - Undergrnd Conductors,Device	Cond Alum	1991	232,992	\$722,260.03	\$3.10	8,911,339	17,451,875.81	\$ 1.96
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1991	31,130	\$119,323.16	\$3.83	8,942,469	17,571,198.97	\$ 1.96
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1991	46,888	\$74,218.03	\$1.58	8,989,357	17,645,417.00	\$ 1.96
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1991	8,907	\$26,814.05	\$3.01	8,998,264	17,672,231.05	\$ 1.96
36700 - Undergrnd Conductors,Device	Cond Alum	1992	299,415	\$997,613.07	\$3.33	9,297,679	18,669,844.12	\$ 2.01
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1992	35,624	\$132,288.92	\$3.71	9,333,303	18,802,133.04	\$ 2.01

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1992	41,126	\$63,016.39	\$1.53	9,374,429	18,865,149.43	\$ 2.01
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1992	13,402	\$41,351.21	\$3.09	9,387,831	18,906,500.64	\$ 2.01
36700 - Undergrnd Conductors,Device	Cond Alum	1993	292,352	\$951,235.33	\$3.25	9,680,183	19,857,735.97	\$ 2.05
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1993	52,853	\$189,474.47	\$3.58	9,733,036	20,047,210.44	\$ 2.06
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1993	44,350	\$73,044.10	\$1.65	9,777,386	20,120,254.54	\$ 2.06
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1993	20,991	\$60,260.58	\$2.87	9,798,377	20,180,515.12	\$ 2.06
36700 - Undergrnd Conductors,Device	Cond Alum	1994	346,671	\$1,205,033.74	\$3.48	10,145,048	21,385,548.86	\$ 2.11
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1994	49,447	\$180,086.48	\$3.64	10,194,495	21,565,635.34	\$ 2.12
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1994	33,394	\$87,791.15	\$2.63	10,227,889	21,653,426.49	\$ 2.12
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1994	45,678	\$86,916.72	\$1.90	10,273,567	21,740,343.21	\$ 2.12
36700 - Undergrnd Conductors,Device	Cond Alum	1995	304,903	\$1,103,265.31	\$3.62	10,578,470	22,843,608.52	\$ 2.16
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1995	50,979	\$195,457.82	\$3.83	10,629,449	23,039,066.34	\$ 2.17
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1995	38,494	\$120,078.76	\$3.12	10,667,943	23,159,145.10	\$ 2.17
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1995	54,999	\$119,298.00	\$2.17	10,722,942	23,278,443.10	\$ 2.17
36700 - Undergrnd Conductors,Device	Cond Alum	1996	378,485	\$1,385,676.59	\$3.66	11,101,427	24,664,119.69	\$ 2.22
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1996	50,238	\$211,267.95	\$4.21	11,151,665	24,875,387.64	\$ 2.23
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1996	59,591	\$129,999.36	\$2.18	11,211,256	25,005,387.00	\$ 2.23
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1996	27,396	\$88,866.10	\$3.24	11,238,652	25,094,253.10	\$ 2.23
36700 - Undergrnd Conductors,Device	Cond Alum	1997	292,064	\$927,797.50	\$3.18	11,530,716	26,022,050.60	\$ 2.26
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1997	225,203	\$623,527.87	\$2.77	11,755,919	26,645,578.47	\$ 2.27
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1997	60,921	\$148,189.26	\$2.43	11,816,840	26,793,767.73	\$ 2.27
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1997	35,726	\$56,313.60	\$1.58	11,852,566	26,850,081.33	\$ 2.27
36700 - Undergrnd Conductors,Device	Cond Alum	1998	415,873	\$1,180,256.66	\$2.84	12,268,439	28,030,337.99	\$ 2.28
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1998	49,472	\$115,715.08	\$2.34	12,317,911	28,146,053.07	\$ 2.28
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1998	55,981	\$110,830.69	\$1.98	12,373,892	28,256,883.76	\$ 2.28
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1998	37,215	\$52,683.38	\$1.42	12,411,107	28,309,567.14	\$ 2.28
36700 - Undergrnd Conductors,Device	Cond Alum	1999	373,966	\$1,103,280.54	\$2.95	12,785,073	29,412,847.68	\$ 2.30
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	1999	38,243	\$85,838.67	\$2.24	12,823,316	29,498,686.35	\$ 2.30
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	1999	29,941	\$67,877.67	\$2.27	12,853,257	29,566,564.02	\$ 2.30
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	1999	45,303	\$60,389.79	\$1.33	12,898,560	29,626,953.81	\$ 2.30
36700 - Undergrnd Conductors,Device	Cond Triplex	1999	250	\$585.00	\$2.34	12,898,810	29,627,538.81	\$ 2.30

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36700 - Undergrnd Conductors,Device	Cond Alum	2000	307,181	\$1,123,717.18	\$3.66	13,205,991	30,751,255.99	\$ 2.33
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2000	46,649	\$134,129.36	\$2.88	13,252,640	30,885,385.35	\$ 2.33
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2000	30,313	\$80,127.77	\$2.64	13,282,953	30,965,513.12	\$ 2.33
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2000	50,033	\$73,763.20	\$1.47	13,332,986	31,039,276.32	\$ 2.33
36700 - Undergrnd Conductors,Device	Cond Alum	2001	280,653	\$1,169,656.71	\$4.17	13,613,639	32,208,933.03	\$ 2.37
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2001	27,047	\$61,997.45	\$2.29	13,640,686	32,270,930.48	\$ 2.37
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2001	19,200	\$53,291.32	\$2.78	13,659,886	32,324,221.80	\$ 2.37
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2001	20,396	\$28,460.16	\$1.40	13,680,282	32,352,681.96	\$ 2.36
36700 - Undergrnd Conductors,Device	Cond Alum	2002	559,406	\$2,129,124.63	\$3.81	14,239,688	34,481,806.59	\$ 2.42
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2002	50,649	\$140,833.31	\$2.78	14,290,337	34,622,639.90	\$ 2.42
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2002	31,786	\$73,676.70	\$2.32	14,322,123	34,696,316.60	\$ 2.42
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2002	48,940	\$65,105.03	\$1.33	14,371,063	34,761,421.63	\$ 2.42
36700 - Undergrnd Conductors,Device	Cond Alum	2003	314,426	\$1,294,748.25	\$4.12	14,685,489	36,056,169.88	\$ 2.46
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2003	32,493	\$116,103.88	\$3.57	14,717,982	36,172,273.76	\$ 2.46
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2003	26,833	\$67,178.79	\$2.50	14,744,815	36,239,452.55	\$ 2.46
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2003	21,095	\$45,094.07	\$2.14	14,765,910	36,284,546.62	\$ 2.46
36700 - Undergrnd Conductors,Device	Cond Alum	2004	444,581	\$1,685,308.34	\$3.79	15,210,491	37,969,854.96	\$ 2.50
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2004	74,610	\$223,397.13	\$2.99	15,285,101	38,193,252.09	\$ 2.50
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2004	50,739	\$120,357.43	\$2.37	15,335,840	38,313,609.52	\$ 2.50
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2004	49,325	\$85,602.44	\$1.74	15,385,165	38,399,211.96	\$ 2.50
36700 - Undergrnd Conductors,Device	Cond Alum	2005	354,578	\$1,499,205.14	\$4.23	15,739,743	39,898,417.10	\$ 2.53
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2005	31,493	\$103,523.69	\$3.29	15,771,236	40,001,940.79	\$ 2.54
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2005	41,089	\$81,066.68	\$1.97	15,812,325	40,083,007.47	\$ 2.53
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2005	26,729	\$68,131.60	\$2.55	15,839,054	40,151,139.07	\$ 2.53
36700 - Undergrnd Conductors,Device	Cond Alum	2006	590,218	\$2,420,243.89	\$4.10	16,429,272	42,571,382.96	\$ 2.59
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2006	47,668	\$150,156.89	\$3.15	16,476,940	42,721,539.85	\$ 2.59
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2006	38,547	\$86,527.75	\$2.24	16,515,487	42,808,067.60	\$ 2.59
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2006	50,557	\$56,182.24	\$1.11	16,566,044	42,864,249.84	\$ 2.59
36700 - Undergrnd Conductors,Device	Cond Quadruplex 600 V	2006	150	\$829.91	\$5.53	16,566,194	42,865,079.75	\$ 2.59
36700 - Undergrnd Conductors,Device	Cond Triplex 15 Kv	2006	129	\$287.48	\$2.23	16,566,323	42,865,367.23	\$ 2.59
36700 - Undergrnd Conductors,Device	Cond Alum	2007	515,862	\$2,436,296.51	\$4.72	17,082,185	45,301,663.74	\$ 2.65

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2007	38,143	\$125,689.50	\$3.30	17,120,328	45,427,353.24	\$ 2.65
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2007	37,858	\$112,223.37	\$2.96	17,158,186	45,539,576.61	\$ 2.65
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2007	40,320	\$52,012.08	\$1.29	17,198,506	45,591,588.69	\$ 2.65
36700 - Undergrnd Conductors,Device	Cond Alum	2008	390,069	\$2,111,143.71	\$5.41	17,588,575	47,702,732.40	\$ 2.71
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2008	19,791	\$59,731.32	\$3.02	17,608,366	47,762,463.72	\$ 2.71
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2008	29,693	\$39,332.36	\$1.32	17,638,059	47,801,796.08	\$ 2.71
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2008	8,345	\$20,883.20	\$2.50	17,646,404	47,822,679.28	\$ 2.71
36700 - Undergrnd Conductors,Device	Cond Alum	2009	380,124	\$1,979,517.88	\$5.21	18,026,528	49,802,197.16	\$ 2.76
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2009	14,854	\$49,379.26	\$3.32	18,041,382	49,851,576.42	\$ 2.76
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2009	22,540	\$27,937.81	\$1.24	18,063,922	49,879,514.23	\$ 2.76
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2009	6,440	\$17,373.56	\$2.70	18,070,362	49,896,887.79	\$ 2.76
36700 - Undergrnd Conductors,Device	Cond Quadruplex 600 V	2009	167	\$997.44	\$5.97	18,070,529	49,897,885.23	\$ 2.76
36700 - Undergrnd Conductors,Device	Cond Alum	2010	400,862	\$2,026,658.09	\$5.06	18,471,391	51,924,543.32	\$ 2.81
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2010	22,471	\$53,865.81	\$2.40	18,493,862	51,978,409.13	\$ 2.81
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2010	14,703	\$31,790.46	\$2.16	18,508,565	52,010,199.59	\$ 2.81
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2010	16,035	\$20,288.90	\$1.27	18,524,600	52,030,488.49	\$ 2.81
36700 - Undergrnd Conductors,Device	Cond Quadruplex 600 V	2010	1,563	\$5,418.89	\$3.47	18,526,163	52,035,907.38	\$ 2.81
36700 - Undergrnd Conductors,Device	Cond Triplex	2010	1,340	\$1,888.49	\$1.41	18,527,503	52,037,795.87	\$ 2.81
36700 - Undergrnd Conductors,Device	Cond Copper Bare	2010	250	\$1,017.13	\$4.07	18,527,753	52,038,813.00	\$ 2.81
36700 - Undergrnd Conductors,Device	Cond Alum	2011	428,424	\$2,224,960.51	\$5.19	18,956,177	54,263,773.51	\$ 2.86
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2011	18,154	\$56,630.19	\$3.12	18,974,331	54,320,403.70	\$ 2.86
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2011	15,037	\$39,236.66	\$2.61	18,989,368	54,359,640.36	\$ 2.86
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2011	21,768	\$22,935.72	\$1.05	19,011,136	54,382,576.08	\$ 2.86
36700 - Undergrnd Conductors,Device	Cond Quadruplex 600 V	2011	1,340	\$3,993.45	\$2.98	19,012,476	54,386,569.53	\$ 2.86
36700 - Undergrnd Conductors,Device	Cond Triplex	2011	50	\$1,273.31	\$25.47	19,012,526	54,387,842.84	\$ 2.86
36700 - Undergrnd Conductors,Device	Cond All Alum	2011	100	\$1,162.17	\$11.62	19,012,626	54,389,005.01	\$ 2.86
36700 - Undergrnd Conductors,Device	Cond Alum	2012	366,231	\$2,094,108.39	\$5.72	19,378,857	56,483,113.40	\$ 2.91
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2012	21,705	\$79,798.28	\$3.68	19,400,562	56,562,911.68	\$ 2.92
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2012	29,891	\$39,086.45	\$1.31	19,430,453	56,601,998.13	\$ 2.91
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2012	16,345	\$37,882.17	\$2.32	19,446,798	56,639,880.30	\$ 2.91
36700 - Undergrnd Conductors,Device	Cond All Alum	2012	2,970	\$19,290.93	\$6.50	19,449,768	56,659,171.23	\$ 2.91

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36700 - Undergrnd Conductors,Device	Cond Quadruplex 600 V	2012	1,350	\$7,757.03	\$5.75	19,451,118	56,666,928.26	\$ 2.91
36700 - Undergrnd Conductors,Device	Cond Triplex	2012	1,000	\$3,444.48	\$3.44	19,452,118	56,670,372.74	\$ 2.91
36700 - Undergrnd Conductors,Device	Cond Duplex	2012	625	\$309.24	\$0.49	19,452,743	56,670,681.98	\$ 2.91
36700 - Undergrnd Conductors,Device	Cond Alum	2013	420,142	\$2,613,452.21	\$6.22	19,872,885	59,284,134.19	\$ 2.98
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2013	10,740	\$44,606.41	\$4.15	19,883,625	59,328,740.60	\$ 2.98
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2013	19,780	\$31,197.98	\$1.58	19,903,405	59,359,938.58	\$ 2.98
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2013	4,735	\$8,033.22	\$1.70	19,908,140	59,367,971.80	\$ 2.98
36700 - Undergrnd Conductors,Device	Cond Quadruplex 600 V	2013	1,315	\$2,813.15	\$2.14	19,909,455	59,370,784.95	\$ 2.98
36700 - Undergrnd Conductors,Device	Cond Triplex	2013	425	\$1,112.44	\$2.62	19,909,880	59,371,897.39	\$ 2.98
36700 - Undergrnd Conductors,Device	Cond Alum	2014	438,426	\$2,742,628.00	\$6.26	20,348,306	62,114,525.39	\$ 3.05
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2014	18,185	\$82,070.20	\$4.51	20,366,491	62,196,595.59	\$ 3.05
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2014	14,509	\$24,476.67	\$1.69	20,381,000	62,221,072.26	\$ 3.05
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2014	5,840	\$10,761.76	\$1.84	20,386,840	62,231,834.02	\$ 3.05
36700 - Undergrnd Conductors,Device	Cond All Alum	2014	650	\$3,895.13	\$5.99	20,387,490	62,235,729.15	\$ 3.05
36700 - Undergrnd Conductors,Device	Cond Quadruplex 600 V	2014	405	\$3,730.69	\$9.21	20,387,895	62,239,459.84	\$ 3.05
36700 - Undergrnd Conductors,Device	Cond Triplex	2014	500	\$921.46	\$1.84	20,388,395	62,240,381.30	\$ 3.05
36700 - Undergrnd Conductors,Device	Cond Alum	2015	7,060	\$56,299.13	\$7.97	20,395,455	62,296,680.43	\$ 3.05
36700 - Undergrnd Conductors,Device	Cond Triplex 600 V	2015	3,550	\$22,543.34	\$6.35	20,399,005	62,319,223.77	\$ 3.06
36700 - Undergrnd Conductors,Device	Cond Duplex 600 V	2015	4,690	\$6,767.44	\$1.44	20,403,695	62,325,991.21	\$ 3.05
36700 - Undergrnd Conductors,Device	Cond Alum 600 V 1 Cond	2015	75	\$1,468.79	\$19.58	20,403,770	\$ 62,327,460.00	\$ 3.05
			20,403,770	\$ 62,327,460.00	\$ 3.05			
			15,270,315	\$ 51,847,784.77	\$ 3.40	83.2%	83.186%	
			2,379,630	\$ 5,794,024.17	\$ 2.43	9.3%	92.482%	
			1,723,566	\$ 2,505,912.16	\$ 1.45	4.0%	96.503%	
			1,010,319	\$ 2,105,353.32	\$ 2.08	3.4%	99.881%	
			6,350	\$ 25,605.18	\$ 4.03	0.0%	99.922%	
			3,720	\$ 24,348.23	\$ 6.55	0.0%	99.961%	
			1,926	\$ 10,761.54	\$ 5.59	0.0%	99.978%	
			3,685	\$ 10,024.92	\$ 2.72	0.0%	99.994%	
			3,594	\$ 3,314.07	\$ 0.92	0.0%	99.999%	

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
	Cond Duplex		665	\$ 331.64	\$ 0.50	0.0%	100.000%	
			20,403,770	\$ 62,327,460.00	\$ 3.05			
			-	\$ -				
		1961	1,008	\$ 615.55	\$ 0.61	1,008	\$ 615.55	\$ 0.61
		1964	960	347.40	\$ 0.36	1,968	962.95	\$ 0.49
		1965	1,093	560.68	\$ 0.51	3,061	1,523.63	\$ 0.50
		1968	3,470	1,645.35	\$ 0.47	6,531	3,168.98	\$ 0.49
		1969	14,911	7,524.37	\$ 0.50	21,442	10,693.35	\$ 0.50
		1970	10,021	2,864.17	\$ 0.29	31,463	13,557.52	\$ 0.43
		1971	31,327	18,124.60	\$ 0.58	62,790	31,682.12	\$ 0.50
		1972	61,957	50,477.34	\$ 0.81	124,747	82,159.46	\$ 0.66
		1973	118,403	84,654.37	\$ 0.71	243,150	166,813.83	\$ 0.69
		1974	154,882	114,118.01	\$ 0.74	398,032	280,931.84	\$ 0.71
		1975	289,890	339,693.07	\$ 1.17	687,922	620,624.91	\$ 0.90
		1976	538,211	640,297.47	\$ 1.19	1,226,133	1,260,922.38	\$ 1.03
		1977	785,594	1,106,002.47	\$ 1.41	2,011,727	2,366,924.85	\$ 1.18
		1978	680,329	1,122,226.77	\$ 1.65	2,692,056	3,489,151.62	\$ 1.30
		1979	993,936	1,645,587.33	\$ 1.66	3,685,992	5,134,738.95	\$ 1.39
		1980	849,766	1,665,287.74	\$ 1.96	4,535,758	6,800,026.69	\$ 1.50
		1981	907,242	1,623,240.15	\$ 1.79	5,443,000	8,423,266.84	\$ 1.55
		1982	552,614	1,486,795.92	\$ 2.69	5,995,614	9,910,062.76	\$ 1.65
		1983	446,637	1,088,494.96	\$ 2.44	6,442,251	10,998,557.72	\$ 1.71
		1984	347,971	749,468.66	\$ 2.15	6,790,222	11,748,026.38	\$ 1.73
		1985	498,904	1,258,556.58	\$ 2.52	7,289,126	13,006,582.96	\$ 1.78
		1986	228,024	580,136.07	\$ 2.54	7,517,150	13,586,719.03	\$ 1.81
		1987	421,444	903,303.74	\$ 2.14	7,938,594	14,490,022.77	\$ 1.83
		1988	248,994	703,412.83	\$ 2.83	8,187,588	15,193,435.60	\$ 1.86
		1989	216,056	650,296.35	\$ 3.01	8,403,644	15,843,731.95	\$ 1.89
		1990	274,703	885,883.83	\$ 3.22	8,678,347	16,729,615.78	\$ 1.93
		1991	319,917	942,615.27	\$ 2.95	8,998,264	17,672,231.05	\$ 1.96

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
		1992	389,567	1,234,269.59	\$ 3.17	9,387,831	18,906,500.64	\$ 2.01
		1993	410,546	1,274,014.48	\$ 3.10	9,798,377	20,180,515.12	\$ 2.06
		1994	475,190	1,559,828.09	\$ 3.28	10,273,567	21,740,343.21	\$ 2.12
		1995	449,375	1,538,099.89	\$ 3.42	10,722,942	23,278,443.10	\$ 2.17
		1996	515,710	1,815,810.00	\$ 3.52	11,238,652	25,094,253.10	\$ 2.23
		1997	613,914	1,755,828.23	\$ 2.86	11,852,566	26,850,081.33	\$ 2.27
		1998	558,541	1,459,485.81	\$ 2.61	12,411,107	28,309,567.14	\$ 2.28
		1999	487,703	1,317,971.67	\$ 2.70	12,898,810	29,627,538.81	\$ 2.30
		2000	434,176	1,411,737.51	\$ 3.25	13,332,986	31,039,276.32	\$ 2.33
		2001	347,296	1,313,405.64	\$ 3.78	13,680,282	32,352,681.96	\$ 2.36
		2002	690,781	2,408,739.67	\$ 3.49	14,371,063	34,761,421.63	\$ 2.42
		2003	394,847	1,523,124.99	\$ 3.86	14,765,910	36,284,546.62	\$ 2.46
		2004	619,255	2,114,665.34	\$ 3.41	15,385,165	38,399,211.96	\$ 2.50
		2005	453,889	1,751,927.11	\$ 3.86	15,839,054	40,151,139.07	\$ 2.53
		2006	727,269	2,714,228.16	\$ 3.73	16,566,323	42,865,367.23	\$ 2.59
		2007	632,183	2,726,221.46	\$ 4.31	17,198,506	45,591,588.69	\$ 2.65
		2008	447,898	2,231,090.59	\$ 4.98	17,646,404	47,822,679.28	\$ 2.71
		2009	424,125	2,075,205.95	\$ 4.89	18,070,529	49,897,885.23	\$ 2.76
		2010	457,224	2,140,927.77	\$ 4.68	18,527,753	52,038,813.00	\$ 2.81
		2011	484,873	2,350,192.01	\$ 4.85	19,012,626	54,389,005.01	\$ 2.86
		2012	440,117	2,281,676.97	\$ 5.18	19,452,743	56,670,681.98	\$ 2.91
		2013	457,137	2,701,215.41	\$ 5.91	19,909,880	59,371,897.39	\$ 2.98
		2014	478,515	2,868,483.91	\$ 5.99	20,388,395	62,240,381.30	\$ 3.05
		2015	15,375	87,078.70	\$ 5.66	20,403,770	62,327,460.00	\$ 3.05
			20,403,770	\$ 62,327,460.00	\$ 3.05			
			-	\$ -				

midpoint 10,201,884.98 \$ 31,163,730.00 \$ 1.53

21	Average Physical Age of Underground Conductor
14	Weighted Cost Average Age of Underground Conductor

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
		34	Age of Average Cost of Underground Conductor					

Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 367 underground Conductor Vintage Count & Cost

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Ave Cost
36800 - Line Transformers	Polemt 11-100 1ph	1960	74	\$26,787.54	\$361.99	74	\$26,787.54	\$ 361.99
36800 - Line Transformers	Polemt 11-100 1ph	1961	473	\$151,266.81	\$319.80	547	178,054.35	\$ 325.51
36800 - Line Transformers	Polemt 0-10 1ph	1961	35	\$5,535.45	\$158.16	582	183,589.80	\$ 315.45
36800 - Line Transformers	Polemt 11-100 1ph	1962	291	\$97,721.81	\$335.81	873	281,311.61	\$ 322.24
36800 - Line Transformers	Polemt 0-10 1ph	1962	187	\$26,788.24	\$143.25	1,060	308,099.85	\$ 290.66
36800 - Line Transformers	Polemt 11-100 1ph	1963	437	\$110,913.00	\$253.81	1,497	419,012.85	\$ 279.90
36800 - Line Transformers	Polemt 0-10 1ph	1963	181	\$25,845.12	\$142.79	1,678	444,857.97	\$ 265.11
36800 - Line Transformers	Polemt 11-100 1ph	1964	571	\$130,684.35	\$228.87	2,249	575,542.32	\$ 255.91
36800 - Line Transformers	Polemt 0-10 1ph	1964	234	\$31,942.17	\$136.51	2,483	607,484.49	\$ 244.66
36800 - Line Transformers	Polemt 11-100 1ph	1965	497	\$138,707.31	\$279.09	2,980	746,191.80	\$ 250.40
36800 - Line Transformers	Polemt 11-100 1ph	1966	105	\$31,154.03	\$296.71	3,085	777,345.83	\$ 251.98
36800 - Line Transformers	Polemt 0-10 1ph	1966	14	\$2,001.23	\$142.95	3,099	779,347.06	\$ 251.48
36800 - Line Transformers	Polemt 11-100 1ph	1967	233	\$75,059.78	\$322.14	3,332	854,406.84	\$ 256.42
36800 - Line Transformers	Polemt 0-10 1ph	1967	66	\$10,258.71	\$155.44	3,398	864,665.55	\$ 254.46
36800 - Line Transformers	Polemt 101-500 1ph	1967	7	\$9,533.41	\$1,361.92	3,405	874,198.96	\$ 256.74
36800 - Line Transformers	Polemt 11-100 1ph	1968	793	\$296,544.97	\$373.95	4,198	1,170,743.93	\$ 278.88
36800 - Line Transformers	Polemt 0-10 1ph	1968	246	\$41,790.56	\$169.88	4,444	1,212,534.49	\$ 272.85
36800 - Line Transformers	Polemt 101-500 1ph	1968	10	\$10,902.20	\$1,090.22	4,454	1,223,436.69	\$ 274.68
36800 - Line Transformers	Polemt 11-100 1ph	1969	527	\$197,665.87	\$375.08	4,981	1,421,102.56	\$ 285.30
36800 - Line Transformers	Polemt 0-10 1ph	1969	77	\$16,423.71	\$213.29	5,058	1,437,526.27	\$ 284.21
36800 - Line Transformers	Polemt 101-500 1ph	1969	12	\$12,647.92	\$1,053.99	5,070	1,450,174.19	\$ 286.03
36800 - Line Transformers	Polemt 11-100 1ph	1970	595	\$213,440.66	\$358.72	5,665	1,663,614.85	\$ 293.67
36800 - Line Transformers	Polemt 0-10 1ph	1970	165	\$30,496.28	\$184.83	5,830	1,694,111.13	\$ 290.59
36800 - Line Transformers	Polemt 101-500 1ph	1970	2	\$12,637.00	\$6,318.50	5,832	1,706,748.13	\$ 292.65
36800 - Line Transformers	Polemt 11-100 1ph	1971	468	\$158,170.99	\$337.97	6,300	1,864,919.12	\$ 296.02
36800 - Line Transformers	Polemt 0-10 1ph	1971	226	\$37,782.38	\$167.18	6,526	1,902,701.50	\$ 291.56
36800 - Line Transformers	Polemt 101-500 1ph	1971	5	\$6,804.66	\$1,360.93	6,531	1,909,506.16	\$ 292.38
36800 - Line Transformers	Polemt 11-100 1ph	1972	346	\$112,016.23	\$323.75	6,877	2,021,522.39	\$ 293.95
36800 - Line Transformers	Polemt 0-10 1ph	1972	164	\$25,191.96	\$153.61	7,041	2,046,714.35	\$ 290.69
36800 - Line Transformers	Polemt 101-500 1ph	1972	8	\$7,833.64	\$979.21	7,049	2,054,547.99	\$ 291.47
36800 - Line Transformers	Polemt 11-100 1ph	1973	639	\$239,958.57	\$375.52	7,688	2,294,506.56	\$ 298.45
36800 - Line Transformers	Polemt 0-10 1ph	1973	203	\$41,155.20	\$202.73	7,891	2,335,661.76	\$ 295.99

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Ave Cost
36800 - Line Transformers	Polemt 101-500 1ph	1973	1	\$1,688.33	\$1,688.33	7,892	2,337,350.09	\$ 296.17
36800 - Line Transformers	Polemt 11-100 1ph	1974	835	\$352,831.35	\$422.55	8,727	2,690,181.44	\$ 308.26
36800 - Line Transformers	Polemt 101-500 1ph	1974	19	\$39,293.39	\$2,068.07	8,746	2,729,474.83	\$ 312.08
36800 - Line Transformers	Polemt 0-10 1ph	1974	182	\$38,083.97	\$209.25	8,928	2,767,558.80	\$ 309.99
36800 - Line Transformers	Polemt 11-100 1ph	1975	781	\$373,148.42	\$477.78	9,709	3,140,707.22	\$ 323.48
36800 - Line Transformers	Polemt 0-10 1ph	1975	216	\$51,866.28	\$240.12	9,925	3,192,573.50	\$ 321.67
36800 - Line Transformers	Polemt 101-500 1ph	1975	20	\$32,305.08	\$1,615.25	9,945	3,224,878.58	\$ 324.27
36800 - Line Transformers	Polemt 11-100 1ph	1976	1,056	\$524,994.54	\$497.15	11,001	3,749,873.12	\$ 340.87
36800 - Line Transformers	Polemt 0-10 1ph	1976	92	\$22,780.58	\$247.62	11,093	3,772,653.70	\$ 340.09
36800 - Line Transformers	Polemt 101-500 1ph	1976	16	\$18,848.16	\$1,178.01	11,109	3,791,501.86	\$ 341.30
36800 - Line Transformers	Polemt 11-100 1ph	1977	1,185	\$643,653.83	\$543.17	12,294	4,435,155.69	\$ 360.76
36800 - Line Transformers	Polemt 0-10 1ph	1977	107	\$27,748.12	\$259.33	12,401	4,462,903.81	\$ 359.88
36800 - Line Transformers	Polemt 101-500 1ph	1977	17	\$21,193.76	\$1,246.69	12,418	4,484,097.57	\$ 361.10
36800 - Line Transformers	Polemt 11-100 1ph	1978	785	\$489,109.39	\$623.07	13,203	4,973,206.96	\$ 376.67
36800 - Line Transformers	Polemt 0-10 1ph	1978	142	\$39,680.28	\$279.44	13,345	5,012,887.24	\$ 375.64
36800 - Line Transformers	Polemt 101-500 1ph	1978	11	\$16,174.61	\$1,470.42	13,356	5,029,061.85	\$ 376.54
36800 - Line Transformers	Polemt 11-100 1ph	1979	636	\$383,707.58	\$603.31	13,992	5,412,769.43	\$ 386.85
36800 - Line Transformers	Polemt 0-10 1ph	1979	190	\$54,926.74	\$289.09	14,182	5,467,696.17	\$ 385.54
36800 - Line Transformers	Polemt 101-500 1ph	1979	12	\$14,864.10	\$1,238.68	14,194	5,482,560.27	\$ 386.26
36800 - Line Transformers	Polemt 11-100 1ph	1980	713	\$549,443.38	\$770.61	14,907	6,032,003.65	\$ 404.64
36800 - Line Transformers	Polemt 0-10 1ph	1980	104	\$34,309.50	\$329.90	15,011	6,066,313.15	\$ 404.12
36800 - Line Transformers	Polemt 101-500 1ph	1980	10	\$13,971.00	\$1,397.10	15,021	6,080,284.15	\$ 404.79
36800 - Line Transformers	Polemt 11-100 1ph	1981	1,439	\$1,046,395.45	\$727.17	16,460	7,126,679.60	\$ 432.97
36800 - Line Transformers	Polemt 0-10 1ph	1981	168	\$57,734.07	\$343.66	16,628	7,184,413.67	\$ 432.07
36800 - Line Transformers	Polemt 101-500 1ph	1981	5	\$7,689.10	\$1,537.82	16,633	7,192,102.77	\$ 432.40
36800 - Line Transformers	Polemt 11-100 1ph	1982	252	\$220,164.36	\$873.67	16,885	7,412,267.13	\$ 438.99
36800 - Line Transformers	Polemt 0-10 1ph	1982	38	\$14,853.25	\$390.88	16,923	7,427,120.38	\$ 438.88
36800 - Line Transformers	Polemt 101-500 1ph	1982	6	\$10,487.58	\$1,747.93	16,929	7,437,607.96	\$ 439.34
36800 - Line Transformers	Polemt 11-100 1ph	1983	1,744	\$1,404,287.63	\$805.21	18,673	8,841,895.59	\$ 473.51
36800 - Line Transformers	Polemt 0-10 1ph	1983	307	\$132,739.64	\$432.38	18,980	8,974,635.23	\$ 472.85
36800 - Line Transformers	Polemt 11-100 1ph	1984	128	\$274,026.02	\$2,140.83	19,108	9,248,661.25	\$ 484.02
36800 - Line Transformers	Polemt 0-10 1ph	1984	104	\$40,082.77	\$385.41	19,212	9,288,744.02	\$ 483.49

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Ave Cost
36800 - Line Transformers	Polemt 101-500 1ph	1984	7	\$16,070.65	\$2,295.81	19,219	9,304,814.67	\$ 484.15
36800 - Line Transformers	Polemt 11-100 1ph	1985	249	\$369,219.67	\$1,482.81	19,468	9,674,034.34	\$ 496.92
36800 - Line Transformers	Polemt 0-10 1ph	1985	75	\$42,570.20	\$567.60	19,543	9,716,604.54	\$ 497.19
36800 - Line Transformers	Polemt 11-100 1ph	1986	146	\$317,912.71	\$2,177.48	19,689	10,034,517.25	\$ 509.65
36800 - Line Transformers	Polemt 0-10 1ph	1986	112	\$62,147.81	\$554.89	19,801	10,096,665.06	\$ 509.91
36800 - Line Transformers	Polemt 101-500 1ph	1986	3	\$8,107.08	\$2,702.36	19,804	10,104,772.14	\$ 510.24
36800 - Line Transformers	Polemt 11-100 1ph	1987	235	\$226,616.84	\$964.33	20,039	10,331,388.98	\$ 515.56
36800 - Line Transformers	Polemt 0-10 1ph	1987	101	\$66,033.33	\$653.80	20,140	10,397,422.31	\$ 516.26
36800 - Line Transformers	Polemt 101-500 1ph	1987	6	\$16,119.60	\$2,686.60	20,146	10,413,541.91	\$ 516.90
36800 - Line Transformers	Polemt 11-100 1ph	1988	545	\$598,702.09	\$1,098.54	20,691	11,012,244.00	\$ 532.22
36800 - Line Transformers	Polemt 0-10 1ph	1988	230	\$181,594.83	\$789.54	20,921	11,193,838.83	\$ 535.05
36800 - Line Transformers	Polemt 101-500 1ph	1988	10	\$22,959.53	\$2,295.95	20,931	11,216,798.36	\$ 535.89
36800 - Line Transformers	Polemt 11-100 1ph	1989	759	\$946,456.45	\$1,246.98	21,690	12,163,254.81	\$ 560.78
36800 - Line Transformers	Polemt 0-10 1ph	1989	307	\$245,000.94	\$798.05	21,997	12,408,255.75	\$ 564.09
36800 - Line Transformers	Polemt 101-500 1ph	1989	18	\$49,347.41	\$2,741.52	22,015	12,457,603.16	\$ 565.87
36800 - Line Transformers	Polemt 11-100 1ph	1990	123	\$135,810.47	\$1,104.15	22,138	12,593,413.63	\$ 568.86
36800 - Line Transformers	Polemt 0-10 1ph	1990	43	\$32,146.97	\$747.60	22,181	12,625,560.60	\$ 569.21
36800 - Line Transformers	Polemt 101-500 1ph	1990	1	\$1,299.46	\$1,299.46	22,182	12,626,860.06	\$ 569.24
36800 - Line Transformers	Polemt 11-100 1ph	1991	202	\$208,097.60	\$1,030.19	22,384	12,834,957.66	\$ 573.40
36800 - Line Transformers	Polemt 0-10 1ph	1991	18	\$10,949.33	\$608.30	22,402	12,845,906.99	\$ 573.43
36800 - Line Transformers	Polemt 101-500 1ph	1991	2	\$10,772.96	\$5,386.48	22,404	12,856,679.95	\$ 573.86
36800 - Line Transformers	Polemt 11-100 1ph	1992	213	\$238,614.04	\$1,120.25	22,617	13,095,293.99	\$ 579.00
36800 - Line Transformers	Polemt 0-10 1ph	1992	22	\$14,356.49	\$652.57	22,639	13,109,650.48	\$ 579.07
36800 - Line Transformers	Polemt 101-500 1ph	1992	(3)	(\$17,888.98)	\$5,962.99	22,636	13,091,761.50	\$ 578.36
36800 - Line Transformers	Polemt 11-100 1ph	1993	377	\$437,290.32	\$1,159.92	23,013	13,529,051.82	\$ 587.89
36800 - Line Transformers	Polemt 0-10 1ph	1993	64	\$53,315.76	\$833.06	23,077	13,582,367.58	\$ 588.57
36800 - Line Transformers	Polemt 101-500 1ph	1993	1	\$3,714.69	\$3,714.69	23,078	13,586,082.27	\$ 588.70
36800 - Line Transformers	Polemt 11-100 1ph	1994	387	\$456,913.27	\$1,180.65	23,465	14,042,995.54	\$ 598.47
36800 - Line Transformers	Polemt 0-10 1ph	1994	122	\$102,104.15	\$836.92	23,587	14,145,099.69	\$ 599.70
36800 - Line Transformers	Polemt 101-500 1ph	1994	1	\$2,231.00	\$2,231.00	23,588	14,147,330.69	\$ 599.77
36800 - Line Transformers	Polemt 11-100 1ph	1995	117	\$146,988.68	\$1,256.31	23,705	14,294,319.37	\$ 603.01
36800 - Line Transformers	Polemt 0-10 1ph	1995	75	\$63,024.92	\$840.33	23,780	14,357,344.29	\$ 603.76

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Ave Cost
36800 - Line Transformers	Polemt 101-500 1ph	1995	1	\$2,475.23	\$2,475.23	23,781	14,359,819.52	\$ 603.84
36800 - Line Transformers	Polemt 11-100 1ph	1996	361	\$459,088.12	\$1,271.71	24,142	14,818,907.64	\$ 613.82
36800 - Line Transformers	Polemt 0-10 1ph	1996	126	\$109,549.99	\$869.44	24,268	14,928,457.63	\$ 615.15
36800 - Line Transformers	Polemt 101-500 1ph	1996	1	\$2,644.21	\$2,644.21	24,269	14,931,101.84	\$ 615.23
36800 - Line Transformers	Polemt 11-100 1ph	1997	381	\$484,469.95	\$1,271.57	24,650	15,415,571.79	\$ 625.38
36800 - Line Transformers	Polemt 0-10 1ph	1997	84	\$63,677.15	\$758.06	24,734	15,479,248.94	\$ 625.83
36800 - Line Transformers	Polemt 101-500 1ph	1997	1	\$2,812.72	\$2,812.72	24,735	15,482,061.66	\$ 625.92
36800 - Line Transformers	Polemt 11-100 1ph	1998	208	\$230,901.93	\$1,110.11	24,943	15,712,963.59	\$ 629.95
36800 - Line Transformers	Polemt 0-10 1ph	1998	88	\$64,328.22	\$731.00	25,031	15,777,291.81	\$ 630.31
36800 - Line Transformers	Polemt 101-500 1ph	1998	-	\$1,583.57	\$0.00	25,031	15,778,875.38	\$ 630.37
36800 - Line Transformers	Polemt 11-100 1ph	1999	350	\$371,563.89	\$1,061.61	25,381	16,150,439.27	\$ 636.32
36800 - Line Transformers	Polemt 0-10 1ph	1999	37	\$24,854.85	\$671.75	25,418	16,175,294.12	\$ 636.37
36800 - Line Transformers	Polemt 101-500 1ph	1999	3	\$7,141.68	\$2,380.56	25,421	16,182,435.80	\$ 636.58
36800 - Line Transformers	Polemt 11-100 1ph	2000	532	\$591,541.10	\$1,111.92	25,953	16,773,976.90	\$ 646.32
36800 - Line Transformers	Polemt 0-10 1ph	2000	142	\$112,296.64	\$790.82	26,095	16,886,273.54	\$ 647.11
36800 - Line Transformers	Polemt 101-500 1ph	2000	4	\$10,020.57	\$2,505.14	26,099	16,896,294.11	\$ 647.39
36800 - Line Transformers	Polemt 11-100 1ph	2001	559	\$623,910.25	\$1,116.12	26,658	17,520,204.36	\$ 657.22
36800 - Line Transformers	Polemt 0-10 1ph	2001	298	\$287,935.43	\$966.23	26,956	17,808,139.79	\$ 660.64
36800 - Line Transformers	Polemt 11-100 1ph	2002	26	\$41,207.63	\$1,584.91	26,982	17,849,347.42	\$ 661.53
36800 - Line Transformers	Polemt 101-500 1ph	2002	1	\$2,579.60	\$2,579.60	26,983	17,851,927.02	\$ 661.60
36800 - Line Transformers	Polemt 11-100 1ph	2003	120	\$133,153.37	\$1,109.61	27,103	17,985,080.39	\$ 663.58
36800 - Line Transformers	Polemt 0-10 1ph	2003	39	\$45,276.02	\$1,160.92	27,142	18,030,356.41	\$ 664.30
36800 - Line Transformers	Polemt 11-100 1ph	2004	562	\$603,873.35	\$1,074.51	27,704	18,634,229.76	\$ 672.62
36800 - Line Transformers	Polemt 0-10 1ph	2004	178	\$114,205.60	\$641.60	27,882	18,748,435.36	\$ 672.42
36800 - Line Transformers	Polemt 101-500 1ph	2004	5	\$6,630.52	\$1,326.10	27,887	18,755,065.88	\$ 672.54
36800 - Line Transformers	Polemt 11-100 1ph	2005	598	\$739,424.98	\$1,236.50	28,485	19,494,490.86	\$ 684.38
36800 - Line Transformers	Polemt 0-10 1ph	2005	177	\$123,915.60	\$700.09	28,662	19,618,406.46	\$ 684.47
36800 - Line Transformers	Polemt 101-500 1ph	2005	8	\$11,690.18	\$1,461.27	28,670	19,630,096.64	\$ 684.69
36800 - Line Transformers	Polemt 11-100 1ph	2006	649	\$1,087,405.90	\$1,675.51	29,319	20,717,502.54	\$ 706.62
36800 - Line Transformers	Polemt 0-10 1ph	2006	109	\$110,913.62	\$1,017.56	29,428	20,828,416.16	\$ 707.78
36800 - Line Transformers	Polemt 11-100 1ph	2007	532	\$1,084,027.07	\$2,037.64	29,960	21,912,443.23	\$ 731.39
36800 - Line Transformers	Polemt 0-10 1ph	2007	107	\$130,511.34	\$1,219.73	30,067	22,042,954.57	\$ 733.13

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Ave Cost
36800 - Line Transformers	Polemt 101-500 1ph	2007	4	\$16,940.95	\$4,235.24	30,071	22,059,895.52	\$ 733.59
36800 - Line Transformers	Polemt 11-100 1ph	2008	620	\$1,297,840.00	\$2,093.29	30,691	23,357,735.52	\$ 761.06
36800 - Line Transformers	Polemt 0-10 1ph	2008	85	\$105,657.16	\$1,243.03	30,776	23,463,392.68	\$ 762.39
36800 - Line Transformers	Polemt 101-500 1ph	2008	1	(\$2,025.61)	(\$2,025.61)	30,777	23,461,367.07	\$ 762.30
36800 - Line Transformers	Polemt 11-100 1ph	2009	454	\$1,036,921.71	\$2,283.97	31,231	24,498,288.78	\$ 784.42
36800 - Line Transformers	Polemt 0-10 1ph	2009	50	\$68,571.87	\$1,371.44	31,281	24,566,860.65	\$ 785.36
36800 - Line Transformers	Polemt 101-500 1ph	2009	1	\$3,084.65	\$3,084.65	31,282	24,569,945.30	\$ 785.43
36800 - Line Transformers	Polemt 11-100 1ph	2010	562	\$1,434,471.68	\$2,552.44	31,844	26,004,416.98	\$ 816.62
36800 - Line Transformers	Polemt 0-10 1ph	2010	101	\$130,552.95	\$1,292.60	31,945	26,134,969.93	\$ 818.12
36800 - Line Transformers	Polemt 101-500 1ph	2010	1	\$5,372.13	\$5,372.13	31,946	26,140,342.06	\$ 818.27
36800 - Line Transformers	Polemt 11-100 1ph	2011	538	\$1,349,335.83	\$2,508.06	32,484	27,489,677.89	\$ 846.25
36800 - Line Transformers	Polemt 0-10 1ph	2011	105	\$143,911.04	\$1,370.58	32,589	27,633,588.93	\$ 847.94
36800 - Line Transformers	Polemt 101-500 1ph	2011	4	\$16,674.66	\$4,168.67	32,593	27,650,263.59	\$ 848.35
36800 - Line Transformers	Polemt 11-100 3ph	2011	1	\$3,629.93	\$3,629.93	32,594	27,653,893.52	\$ 848.44
36800 - Line Transformers	Polemt 11-100 1ph	2012	550	\$1,459,328.40	\$2,653.32	33,144	29,113,221.92	\$ 878.39
36800 - Line Transformers	Polemt 0-10 1ph	2012	107	\$133,937.78	\$1,251.75	33,251	29,247,159.70	\$ 879.59
36800 - Line Transformers	Polemt 101-500 1ph	2012	2	\$6,746.53	\$3,373.27	33,253	29,253,906.23	\$ 879.74
36800 - Line Transformers	Polemt 11-100 1ph	2013	453	\$1,549,303.11	\$3,420.10	33,706	30,803,209.34	\$ 913.88
36800 - Line Transformers	Polemt 0-10 1ph	2013	83	\$97,910.47	\$1,179.64	33,789	30,901,119.81	\$ 914.53
36800 - Line Transformers	Polemt 101-500 1ph	2013	4	\$18,178.09	\$4,544.52	33,793	30,919,297.90	\$ 914.96
36800 - Line Transformers	Polemt 11-100 3ph	2013	1	\$2,607.27	\$2,607.27	33,794	30,921,905.17	\$ 915.01
36800 - Line Transformers	Polemt 11-100 1ph	2014	475	\$1,734,539.74	\$3,651.66	34,269	32,656,444.91	\$ 952.94
36800 - Line Transformers	Polemt 0-10 1ph	2014	72	\$110,083.01	\$1,528.93	34,341	32,766,527.92	\$ 954.15
36800 - Line Transformers	Polemt 11-100 1ph	2015	51	\$177,883.78	\$3,487.92	34,392	32,944,411.70	\$ 957.91
36800 - Line Transformers	Polemt 0-10 1ph	2015	7	\$9,411.15	\$1,344.45	34,399	32,953,822.85	\$ 957.99
			34,399	\$ 32,953,822.85	\$ 957.99			
		1960	74	\$ 26,787.54	\$ 361.99	74	\$ 26,787.54	\$ 361.99
		1961	508	156,802.26	\$ 308.67	582	183,589.80	\$ 315.45
		1962	478	124,510.05	\$ 260.48	1,060	308,099.85	\$ 290.66
		1963	618	136,758.12	\$ 221.29	1,678	444,857.97	\$ 265.11
		1964	805	162,626.52	\$ 202.02	2,483	607,484.49	\$ 244.66

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Ave Cost
		1965	497	138,707.31	\$ 279.09	2,980	746,191.80	\$ 250.40
		1966	119	33,155.26	\$ 278.62	3,099	779,347.06	\$ 251.48
		1967	306	94,851.90	\$ 309.97	3,405	874,198.96	\$ 256.74
		1968	1,049	349,237.73	\$ 332.92	4,454	1,223,436.69	\$ 274.68
		1969	616	226,737.50	\$ 368.08	5,070	1,450,174.19	\$ 286.03
		1970	762	256,573.94	\$ 336.71	5,832	1,706,748.13	\$ 292.65
		1971	699	202,758.03	\$ 290.07	6,531	1,909,506.16	\$ 292.38
		1972	518	145,041.83	\$ 280.00	7,049	2,054,547.99	\$ 291.47
		1973	843	282,802.10	\$ 335.47	7,892	2,337,350.09	\$ 296.17
		1974	1,036	430,208.71	\$ 415.26	8,928	2,767,558.80	\$ 309.99
		1975	1,017	457,319.78	\$ 449.68	9,945	3,224,878.58	\$ 324.27
		1976	1,164	566,623.28	\$ 486.79	11,109	3,791,501.86	\$ 341.30
		1977	1,309	692,595.71	\$ 529.10	12,418	4,484,097.57	\$ 361.10
		1978	938	544,964.28	\$ 580.99	13,356	5,029,061.85	\$ 376.54
		1979	838	453,498.42	\$ 541.17	14,194	5,482,560.27	\$ 386.26
		1980	827	597,723.88	\$ 722.76	15,021	6,080,284.15	\$ 404.79
		1981	1,612	1,111,818.62	\$ 689.71	16,633	7,192,102.77	\$ 432.40
		1982	296	245,505.19	\$ 829.41	16,929	7,437,607.96	\$ 439.34
		1983	2,051	1,537,027.27	\$ 749.40	18,980	8,974,635.23	\$ 472.85
		1984	239	330,179.44	\$ 1,381.50	19,219	9,304,814.67	\$ 484.15
		1985	324	411,789.87	\$ 1,270.96	19,543	9,716,604.54	\$ 497.19
		1986	261	388,167.60	\$ 1,487.23	19,804	10,104,772.14	\$ 510.24
		1987	342	308,769.77	\$ 902.84	20,146	10,413,541.91	\$ 516.90
		1988	785	803,256.45	\$ 1,023.26	20,931	11,216,798.36	\$ 535.89
		1989	1,084	1,240,804.80	\$ 1,144.65	22,015	12,457,603.16	\$ 565.87
		1990	167	169,256.90	\$ 1,013.51	22,182	12,626,860.06	\$ 569.24
		1991	222	229,819.89	\$ 1,035.22	22,404	12,856,679.95	\$ 573.86
		1992	232	235,081.55	\$ 1,013.28	22,636	13,091,761.50	\$ 578.36
		1993	442	494,320.77	\$ 1,118.37	23,078	13,586,082.27	\$ 588.70
		1994	510	561,248.42	\$ 1,100.49	23,588	14,147,330.69	\$ 599.77
		1995	193	212,488.83	\$ 1,100.98	23,781	14,359,819.52	\$ 603.84
		1996	488	571,282.32	\$ 1,170.66	24,269	14,931,101.84	\$ 615.23

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Ave Cost
		1997	466	550,959.82	\$ 1,182.32	24,735	15,482,061.66	\$ 625.92
		1998	296	296,813.72	\$ 1,002.75	25,031	15,778,875.38	\$ 630.37
		1999	390	403,560.42	\$ 1,034.77	25,421	16,182,435.80	\$ 636.58
		2000	678	713,858.31	\$ 1,052.89	26,099	16,896,294.11	\$ 647.39
		2001	857	911,845.68	\$ 1,064.00	26,956	17,808,139.79	\$ 660.64
		2002	27	43,787.23	\$ 1,621.75	26,983	17,851,927.02	\$ 661.60
		2003	159	178,429.39	\$ 1,122.20	27,142	18,030,356.41	\$ 664.30
		2004	745	724,709.47	\$ 972.76	27,887	18,755,065.88	\$ 672.54
		2005	783	875,030.76	\$ 1,117.54	28,670	19,630,096.64	\$ 684.69
		2006	758	1,198,319.52	\$ 1,580.90	29,428	20,828,416.16	\$ 707.78
		2007	643	1,231,479.36	\$ 1,915.21	30,071	22,059,895.52	\$ 733.59
		2008	706	1,401,471.55	\$ 1,985.09	30,777	23,461,367.07	\$ 762.30
		2009	505	1,108,578.23	\$ 2,195.20	31,282	24,569,945.30	\$ 785.43
		2010	664	1,570,396.76	\$ 2,365.06	31,946	26,140,342.06	\$ 818.27
		2011	648	1,513,551.46	\$ 2,335.73	32,594	27,653,893.52	\$ 848.44
		2012	659	1,600,012.71	\$ 2,427.94	33,253	29,253,906.23	\$ 879.74
		2013	541	1,667,998.94	\$ 3,083.18	33,794	30,921,905.17	\$ 915.01
		2014	547	1,844,622.75	\$ 3,372.25	34,341	32,766,527.92	\$ 954.15
		2015	58	187,294.93	\$ 3,229.22	34,399	32,953,822.85	\$ 957.99
			34,399	\$ 32,953,822.85	\$ 957.99			
			-	\$ -				

midpoint 17,200 \$ 16,476,911 \$ 478.99

32	Average Physical Age of Pole Mount Line Transformers
15	Weighted Cost Average Age of Pole Mount Line Transformers
31	Age of Average Cost of Pole Mount Transformers

Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 368 Pole Mount Transformer Vintage Count & Cost

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36800 - Line Transformers	Padmt 11-100 1ph	1972	37	\$17,451.60	\$471.66	37	\$ 17,451.60	\$ 471.66
36800 - Line Transformers	Padmt 11-100 1ph	1973	195	\$106,720.82	\$547.29	232	124,172.42	\$ 535.23
36800 - Line Transformers	Padmt 11-100 1ph	1974	193	\$108,052.01	\$559.85	425	232,224.43	\$ 546.41
36800 - Line Transformers	Padmt 101-500 3ph	1974	15	\$43,845.37	\$2,923.02	440	276,069.80	\$ 627.43
36800 - Line Transformers	Padmt 11-100 1ph	1975	301	\$116,213.50	\$386.09	741	392,283.30	\$ 529.40
36800 - Line Transformers	Padmt 101-500 3ph	1975	23	\$69,142.03	\$3,006.18	764	461,425.33	\$ 603.96
36800 - Line Transformers	Padmt 11-100 1ph	1976	225	\$158,122.44	\$702.77	989	619,547.77	\$ 626.44
36800 - Line Transformers	Padmt 101-500 3ph	1976	15	\$37,943.47	\$2,529.56	1,004	657,491.24	\$ 654.87
36800 - Line Transformers	Padmt 101-500 1ph	1976	7	\$6,491.34	\$927.33	1,011	663,982.58	\$ 656.76
36800 - Line Transformers	Padmt 11-100 3ph	1976	2	\$3,134.40	\$1,567.20	1,013	667,116.98	\$ 658.56
36800 - Line Transformers	Padmt 11-100 1ph	1977	98	\$70,953.05	\$724.01	1,111	738,070.03	\$ 664.33
36800 - Line Transformers	Padmt 11-100 3ph	1977	18	\$37,526.52	\$2,084.81	1,129	775,596.55	\$ 686.98
36800 - Line Transformers	Padmt 101-500 1ph	1977	2	\$2,763.00	\$1,381.50	1,131	778,359.55	\$ 688.20
36800 - Line Transformers	Padmt 11-100 1ph	1978	487	\$382,223.24	\$784.85	1,618	1,160,582.79	\$ 717.29
36800 - Line Transformers	Padmt 11-100 3ph	1978	18	\$39,548.98	\$2,197.17	1,636	1,200,131.77	\$ 733.58
36800 - Line Transformers	Padmt 101-500 1ph	1978	11	\$16,951.00	\$1,541.00	1,647	1,217,082.77	\$ 738.97
36800 - Line Transformers	Padmt 11-100 1ph	1979	529	\$406,479.92	\$768.39	2,176	1,623,562.69	\$ 746.12
36800 - Line Transformers	Padmt 101-500 3ph	1979	6	\$18,360.33	\$3,060.06	2,182	1,641,923.02	\$ 752.49
36800 - Line Transformers	Padmt 101-500 1ph	1979	7	\$10,747.14	\$1,535.31	2,189	1,652,670.16	\$ 754.99
36800 - Line Transformers	Padmt 11-100 1ph	1980	185	\$158,869.92	\$858.76	2,374	1,811,540.08	\$ 763.08
36800 - Line Transformers	Padmt 101-500 3ph	1980	18	\$68,860.27	\$3,825.57	2,392	1,880,400.35	\$ 786.12
36800 - Line Transformers	Padmt 101-500 1ph	1980	17	\$29,783.28	\$1,751.96	2,409	1,910,183.63	\$ 792.94
36800 - Line Transformers	Padmt 11-100 3ph	1980	8	\$19,839.32	\$2,479.92	2,417	1,930,022.95	\$ 798.52
36800 - Line Transformers	Padmt 101-500 3ph	1981	39	\$180,077.24	\$4,617.37	2,456	2,110,100.19	\$ 859.16
36800 - Line Transformers	Padmt 11-100 3ph	1981	24	\$72,868.15	\$3,036.17	2,480	2,182,968.34	\$ 880.23
36800 - Line Transformers	Padmt 11-100 1ph	1981	55	\$55,360.64	\$1,006.56	2,535	2,238,328.98	\$ 882.97
36800 - Line Transformers	Padmt 101-500 1ph	1981	4	\$8,501.34	\$2,125.34	2,539	2,246,830.32	\$ 884.93
36800 - Line Transformers	Padmt 11-100 1ph	1982	83	\$89,392.84	\$1,077.02	2,622	2,336,223.16	\$ 891.01
36800 - Line Transformers	Padmt 101-500 3ph	1982	9	\$58,172.08	\$6,463.56	2,631	2,394,395.24	\$ 910.07
36800 - Line Transformers	Padmt 501-1500 3ph	1982	1	\$14,392.12	\$14,392.12	2,632	2,408,787.36	\$ 915.19
36800 - Line Transformers	Padmt 11-100 1ph	1983	252	\$251,360.98	\$997.46	2,884	2,660,148.34	\$ 922.38

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36800 - Line Transformers	Padmt 101-500 3ph	1983	6	\$27,211.11	\$4,535.19	2,890	2,687,359.45	\$ 929.88
36800 - Line Transformers	Padmt 501-1500 3ph	1983	1	\$14,939.66	\$14,939.66	2,891	2,702,299.11	\$ 934.73
36800 - Line Transformers	Padmt 101-500 3ph	1984	26	\$109,116.67	\$4,196.80	2,917	2,811,415.78	\$ 963.80
36800 - Line Transformers	Padmt 11-100 1ph	1984	104	\$104,205.33	\$1,001.97	3,021	2,915,621.11	\$ 965.12
36800 - Line Transformers	Padmt 11-100 3ph	1984	7	\$24,122.87	\$3,446.12	3,028	2,939,743.98	\$ 970.85
36800 - Line Transformers	Padmt 501-1500 3ph	1984	1	\$17,170.66	\$17,170.66	3,029	2,956,914.64	\$ 976.20
36800 - Line Transformers	Padmt 101-500 1ph	1984	4	\$9,766.00	\$2,441.50	3,033	2,966,680.64	\$ 978.13
36800 - Line Transformers	Padmt 101-500 3ph	1985	31	\$153,097.68	\$4,938.63	3,064	3,119,778.32	\$ 1,018.20
36800 - Line Transformers	Padmt 11-100 1ph	1985	47	\$60,588.17	\$1,289.11	3,111	3,180,366.49	\$ 1,022.30
36800 - Line Transformers	Padmt 11-100 3ph	1985	4	\$14,220.00	\$3,555.00	3,115	3,194,586.49	\$ 1,025.55
36800 - Line Transformers	Padmt 11-100 1ph	1986	78	\$96,572.62	\$1,238.11	3,193	3,291,159.11	\$ 1,030.74
36800 - Line Transformers	Padmt 101-500 3ph	1986	11	\$60,295.78	\$5,481.43	3,204	3,351,454.89	\$ 1,046.02
36800 - Line Transformers	Padmt 11-100 3ph	1986	10	\$37,647.63	\$3,764.76	3,214	3,389,102.52	\$ 1,054.48
36800 - Line Transformers	Padmt 101-500 1ph	1986	1	\$2,498.47	\$2,498.47	3,215	3,391,600.99	\$ 1,054.93
36800 - Line Transformers	Padmt 11-100 1ph	1987	136	\$166,322.61	\$1,222.96	3,351	3,557,923.60	\$ 1,061.75
36800 - Line Transformers	Padmt 101-500 3ph	1987	16	\$74,671.58	\$4,666.97	3,367	3,632,595.18	\$ 1,078.88
36800 - Line Transformers	Padmt 11-100 3ph	1987	8	\$27,677.39	\$3,459.67	3,375	3,660,272.57	\$ 1,084.53
36800 - Line Transformers	Padmt 101-500 1ph	1987	1	\$3,943.76	\$3,943.76	3,376	3,664,216.33	\$ 1,085.37
36800 - Line Transformers	Padmt 101-500 3ph	1988	30	\$170,705.32	\$5,690.18	3,406	3,834,921.65	\$ 1,125.93
36800 - Line Transformers	Padmt 11-100 1ph	1988	66	\$95,804.75	\$1,451.59	3,472	3,930,726.40	\$ 1,132.12
36800 - Line Transformers	Padmt 501-1500 3ph	1988	3	\$42,902.28	\$14,300.76	3,475	3,973,628.68	\$ 1,143.49
36800 - Line Transformers	Padmt 101-500 1ph	1988	5	\$13,411.69	\$2,682.34	3,480	3,987,040.37	\$ 1,145.70
36800 - Line Transformers	Padmt 11-100 3ph	1988	1	\$3,829.62	\$3,829.62	3,481	3,990,869.99	\$ 1,146.47
36800 - Line Transformers	Padmt 11-100 1ph	1989	293	\$418,611.53	\$1,428.71	3,774	4,409,481.52	\$ 1,168.38
36800 - Line Transformers	Padmt 101-500 3ph	1989	33	\$175,551.91	\$5,319.75	3,807	4,585,033.43	\$ 1,204.37
36800 - Line Transformers	Padmt 11-100 3ph	1989	16	\$60,779.69	\$3,798.73	3,823	4,645,813.12	\$ 1,215.23
36800 - Line Transformers	Padmt 101-500 1ph	1989	7	\$44,164.64	\$6,309.23	3,830	4,689,977.76	\$ 1,224.54
36800 - Line Transformers	Padmt 501-1500 3ph	1989	3	\$36,935.28	\$12,311.76	3,833	4,726,913.04	\$ 1,233.21
36800 - Line Transformers	Padmt 1501+ 3ph	1989	1	\$22,144.90	\$22,144.90	3,834	4,749,057.94	\$ 1,238.67
36800 - Line Transformers	Padmt 11-100 1ph	1990	128	\$171,547.67	\$1,340.22	3,962	4,920,605.61	\$ 1,241.95
36800 - Line Transformers	Padmt 101-500 3ph	1990	20	\$104,365.29	\$5,218.26	3,982	5,024,970.90	\$ 1,261.92

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36800 - Line Transformers	Padmt 11-100 3ph	1990	17	\$62,919.28	\$3,701.13	3,999	5,087,890.18	\$ 1,272.29
36800 - Line Transformers	Padmt 501-1500 3ph	1990	4	\$50,125.68	\$12,531.42	4,003	5,138,015.86	\$ 1,283.54
36800 - Line Transformers	Padmt 1501+ 3ph	1990	1	\$27,672.20	\$27,672.20	4,004	5,165,688.06	\$ 1,290.13
36800 - Line Transformers	Padmt 11-100 1ph	1991	140	\$182,713.62	\$1,305.10	4,144	5,348,401.68	\$ 1,290.64
36800 - Line Transformers	Padmt 101-500 3ph	1991	12	\$101,326.26	\$8,443.86	4,156	5,449,727.94	\$ 1,311.29
36800 - Line Transformers	Padmt 101-500 1ph	1991	7	\$37,337.63	\$5,333.95	4,163	5,487,065.57	\$ 1,318.06
36800 - Line Transformers	Padmt 11-100 3ph	1991	7	\$26,231.75	\$3,747.39	4,170	5,513,297.32	\$ 1,322.13
36800 - Line Transformers	Padmt 501-1500 3ph	1991	1	\$13,070.20	\$13,070.20	4,171	5,526,367.52	\$ 1,324.95
36800 - Line Transformers	Padmt 101-500 3ph	1992	18	\$75,800.80	\$4,211.16	4,189	5,602,168.32	\$ 1,337.35
36800 - Line Transformers	Padmt 501-1500 3ph	1992	5	\$63,494.82	\$12,698.96	4,194	5,665,663.14	\$ 1,350.90
36800 - Line Transformers	Padmt 11-100 1ph	1992	31	\$46,481.19	\$1,499.39	4,225	5,712,144.33	\$ 1,351.99
36800 - Line Transformers	Padmt 11-100 3ph	1992	5	\$21,814.71	\$4,362.94	4,230	5,733,959.04	\$ 1,355.55
36800 - Line Transformers	Padmt 101-500 1ph	1992	1	\$2,643.16	\$2,643.16	4,231	5,736,602.20	\$ 1,355.85
36800 - Line Transformers	Padmt 11-100 1ph	1993	144	\$206,002.83	\$1,430.58	4,375	5,942,605.03	\$ 1,358.31
36800 - Line Transformers	Padmt 101-500 3ph	1993	20	\$123,467.98	\$6,173.40	4,395	6,066,073.01	\$ 1,380.22
36800 - Line Transformers	Padmt 501-1500 3ph	1993	4	\$55,405.01	\$13,851.25	4,399	6,121,478.02	\$ 1,391.56
36800 - Line Transformers	Padmt 11-100 3ph	1993	10	\$44,359.70	\$4,435.97	4,409	6,165,837.72	\$ 1,398.47
36800 - Line Transformers	Padmt 11-100 1ph	1994	207	\$283,756.06	\$1,370.80	4,616	6,449,593.78	\$ 1,397.23
36800 - Line Transformers	Padmt 101-500 3ph	1994	30	\$165,470.64	\$5,515.69	4,646	6,615,064.42	\$ 1,423.82
36800 - Line Transformers	Padmt 11-100 3ph	1994	22	\$90,253.81	\$4,102.45	4,668	6,705,318.23	\$ 1,436.44
36800 - Line Transformers	Padmt 501-1500 3ph	1994	6	\$76,601.38	\$12,766.90	4,674	6,781,919.61	\$ 1,450.99
36800 - Line Transformers	Padmt 1501+ 3ph	1994	1	\$25,119.45	\$25,119.45	4,675	6,807,039.06	\$ 1,456.05
36800 - Line Transformers	Padmt 101-500 1ph	1994	2	\$5,410.76	\$2,705.38	4,677	6,812,449.82	\$ 1,456.59
36800 - Line Transformers	Padmt 11-100 1ph	1995	223	\$339,948.50	\$1,524.43	4,900	7,152,398.32	\$ 1,459.67
36800 - Line Transformers	Padmt 101-500 3ph	1995	31	\$208,903.83	\$6,738.83	4,931	7,361,302.15	\$ 1,492.86
36800 - Line Transformers	Padmt 501-1500 3ph	1995	8	\$107,560.44	\$13,445.06	4,939	7,468,862.59	\$ 1,512.22
36800 - Line Transformers	Padmt 1501+ 3ph	1995	4	\$94,802.74	\$23,700.69	4,943	7,563,665.33	\$ 1,530.18
36800 - Line Transformers	Padmt 11-100 3ph	1995	8	\$36,587.27	\$4,573.41	4,951	7,600,252.60	\$ 1,535.09
36800 - Line Transformers	Padmt 101-500 1ph	1995	2	\$6,004.35	\$3,002.18	4,953	7,606,256.95	\$ 1,535.69
36800 - Line Transformers	Padmt 101-500 3ph	1996	57	\$410,103.69	\$7,194.80	5,010	8,016,360.64	\$ 1,600.07
36800 - Line Transformers	Padmt 11-100 1ph	1996	220	\$346,946.47	\$1,577.03	5,230	8,363,307.11	\$ 1,599.10

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36800 - Line Transformers	Padmt 11-100 3ph	1996	23	\$111,681.46	\$4,855.72	5,253	8,474,988.57	\$ 1,613.36
36800 - Line Transformers	Padmt 501-1500 3ph	1996	7	\$107,239.08	\$15,319.87	5,260	8,582,227.65	\$ 1,631.60
36800 - Line Transformers	Padmt 1501+ 3ph	1996	2	\$61,102.83	\$30,551.42	5,262	8,643,330.48	\$ 1,642.59
36800 - Line Transformers	Padmt 101-500 1ph	1996	3	\$8,378.88	\$2,792.96	5,265	8,651,709.36	\$ 1,643.25
36800 - Line Transformers	Padmt 101-500 3ph	1997	71	\$485,747.43	\$6,841.51	5,336	9,137,456.79	\$ 1,712.42
36800 - Line Transformers	Padmt 11-100 1ph	1997	246	\$361,862.94	\$1,470.99	5,582	9,499,319.73	\$ 1,701.78
36800 - Line Transformers	Padmt 11-100 3ph	1997	23	\$95,137.14	\$4,136.40	5,605	9,594,456.87	\$ 1,711.77
36800 - Line Transformers	Padmt 501-1500 3ph	1997	5	\$55,210.08	\$11,042.02	5,610	9,649,666.95	\$ 1,720.08
36800 - Line Transformers	Padmt 101-500 1ph	1997	1	\$3,404.32	\$3,404.32	5,611	9,653,071.27	\$ 1,720.38
36800 - Line Transformers	Padmt 101-500 3ph	1998	54	\$324,733.39	\$6,013.58	5,665	9,977,804.66	\$ 1,761.31
36800 - Line Transformers	Padmt 501-1500 3ph	1998	8	\$104,395.76	\$13,049.47	5,673	10,082,200.42	\$ 1,777.23
36800 - Line Transformers	Padmt 101-500 1ph	1998	16	\$85,350.04	\$5,334.38	5,689	10,167,550.46	\$ 1,787.23
36800 - Line Transformers	Padmt 11-100 3ph	1998	18	\$68,822.79	\$3,823.49	5,707	10,236,373.25	\$ 1,793.65
36800 - Line Transformers	Padmt 1501+ 3ph	1998	2	\$58,998.98	\$29,499.49	5,709	10,295,372.23	\$ 1,803.36
36800 - Line Transformers	Padmt 11-100 1ph	1998	34	\$54,807.83	\$1,612.00	5,743	10,350,180.06	\$ 1,802.23
36800 - Line Transformers	Padmt 101-500 3ph	1999	60	\$348,000.20	\$5,800.00	5,803	10,698,180.26	\$ 1,843.56
36800 - Line Transformers	Padmt 11-100 1ph	1999	123	\$155,729.91	\$1,266.10	5,926	10,853,910.17	\$ 1,831.57
36800 - Line Transformers	Padmt 501-1500 3ph	1999	11	\$137,133.56	\$12,466.69	5,937	10,991,043.73	\$ 1,851.28
36800 - Line Transformers	Padmt 11-100 3ph	1999	33	\$103,124.75	\$3,124.99	5,970	11,094,168.48	\$ 1,858.32
36800 - Line Transformers	Padmt 101-500 1ph	1999	41	\$57,102.83	\$1,392.75	6,011	11,151,271.31	\$ 1,855.14
36800 - Line Transformers	Padmt 1501+ 3ph	1999	2	\$38,835.46	\$19,417.73	6,013	11,190,106.77	\$ 1,860.99
36800 - Line Transformers	Padmt 11-100 1ph	2000	203	\$251,345.53	\$1,238.16	6,216	11,441,452.30	\$ 1,840.65
36800 - Line Transformers	Padmt 501-1500 3ph	2000	17	\$222,011.78	\$13,059.52	6,233	11,663,464.08	\$ 1,871.24
36800 - Line Transformers	Padmt 101-500 3ph	2000	39	\$221,283.00	\$5,673.92	6,272	11,884,747.08	\$ 1,894.89
36800 - Line Transformers	Padmt 1501+ 3ph	2000	7	\$181,073.11	\$25,867.59	6,279	12,065,820.19	\$ 1,921.61
36800 - Line Transformers	Padmt 11-100 3ph	2000	7	\$32,545.16	\$4,649.31	6,286	12,098,365.35	\$ 1,924.65
36800 - Line Transformers	Padmt 101-500 1ph	2000	2	\$4,618.65	\$2,309.32	6,288	12,102,984.00	\$ 1,924.77
36800 - Line Transformers	Padmt 11-100 1ph	2001	104	\$148,302.50	\$1,425.99	6,392	12,251,286.50	\$ 1,916.66
36800 - Line Transformers	Padmt 101-500 3ph	2001	21	\$125,903.40	\$5,995.40	6,413	12,377,189.90	\$ 1,930.02
36800 - Line Transformers	Padmt 1501+ 3ph	2001	2	\$27,683.69	\$13,841.85	6,415	12,404,873.59	\$ 1,933.73
36800 - Line Transformers	Padmt 501-1500 3ph	2001	2	\$24,893.53	\$12,446.77	6,417	12,429,767.12	\$ 1,937.01

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36800 - Line Transformers	Padmt 101-500 1ph	2001	2	\$3,690.93	\$1,845.47	6,419	12,433,458.05	\$ 1,936.98
36800 - Line Transformers	Padmt 101-500 3ph	2002	12	\$83,629.55	\$6,969.13	6,431	12,517,087.60	\$ 1,946.37
36800 - Line Transformers	Padmt 11-100 1ph	2002	50	\$70,448.09	\$1,408.96	6,481	12,587,535.69	\$ 1,942.22
36800 - Line Transformers	Padmt 501-1500 3ph	2002	3	\$45,325.37	\$15,108.46	6,484	12,632,861.06	\$ 1,948.31
36800 - Line Transformers	Padmt 11-100 3ph	2002	6	\$25,393.21	\$4,232.20	6,490	12,658,254.27	\$ 1,950.42
36800 - Line Transformers	Padmt 1501+ 3ph	2002	1	\$18,283.04	\$18,283.04	6,491	12,676,537.31	\$ 1,952.94
36800 - Line Transformers	Padmt 11-100 1ph	2003	161	\$237,482.49	\$1,475.05	6,652	12,914,019.80	\$ 1,941.37
36800 - Line Transformers	Padmt 501-1500 3ph	2003	10	\$228,536.95	\$22,853.70	6,662	13,142,556.75	\$ 1,972.76
36800 - Line Transformers	Padmt 101-500 3ph	2003	20	\$164,875.64	\$8,243.78	6,682	13,307,432.39	\$ 1,991.53
36800 - Line Transformers	Padmt 1501+ 3ph	2003	5	\$140,501.71	\$28,100.34	6,687	13,447,934.10	\$ 2,011.06
36800 - Line Transformers	Padmt 11-100 3ph	2003	7	\$25,730.49	\$3,675.78	6,694	13,473,664.59	\$ 2,012.80
36800 - Line Transformers	Padmt 101-500 1ph	2003	4	\$8,002.85	\$2,000.71	6,698	13,481,667.44	\$ 2,012.79
36800 - Line Transformers	Padmt 11-100 1ph	2004	307	\$527,819.28	\$1,719.28	7,005	14,009,486.72	\$ 1,999.93
36800 - Line Transformers	Padmt 101-500 3ph	2004	64	\$464,331.47	\$7,255.18	7,069	14,473,818.19	\$ 2,047.51
36800 - Line Transformers	Padmt 501-1500 3ph	2004	24	\$437,116.09	\$18,213.17	7,093	14,910,934.28	\$ 2,102.20
36800 - Line Transformers	Padmt 1501+ 3ph	2004	5	\$120,438.15	\$24,087.63	7,098	15,031,372.43	\$ 2,117.69
36800 - Line Transformers	Padmt 11-100 3ph	2004	17	\$67,328.46	\$3,960.50	7,115	15,098,700.89	\$ 2,122.09
36800 - Line Transformers	Padmt 101-500 1ph	2004	2	\$8,870.99	\$4,435.50	7,117	15,107,571.88	\$ 2,122.74
36800 - Line Transformers	Padmt 101-500 3ph	2005	78	\$600,117.45	\$7,693.81	7,195	15,707,689.33	\$ 2,183.14
36800 - Line Transformers	Padmt 11-100 1ph	2005	306	\$594,618.52	\$1,943.20	7,501	16,302,307.85	\$ 2,173.35
36800 - Line Transformers	Padmt 501-1500 3ph	2005	9	\$157,737.49	\$17,526.39	7,510	16,460,045.34	\$ 2,191.75
36800 - Line Transformers	Padmt 1501+ 3ph	2005	6	\$138,438.58	\$23,073.10	7,516	16,598,483.92	\$ 2,208.42
36800 - Line Transformers	Padmt 11-100 3ph	2005	13	\$53,706.05	\$4,131.23	7,529	16,652,189.97	\$ 2,211.74
36800 - Line Transformers	Padmt 101-500 1ph	2005	3	\$9,733.10	\$3,244.37	7,532	16,661,923.07	\$ 2,212.15
36800 - Line Transformers	Padmt 101-500 3ph	2006	120	\$1,234,048.06	\$10,283.73	7,652	17,895,971.13	\$ 2,338.73
36800 - Line Transformers	Padmt 11-100 1ph	2006	379	\$1,045,860.62	\$2,759.53	8,031	18,941,831.75	\$ 2,358.59
36800 - Line Transformers	Padmt 1501+ 3ph	2006	10	\$473,875.75	\$47,387.58	8,041	19,415,707.50	\$ 2,414.59
36800 - Line Transformers	Padmt 501-1500 3ph	2006	17	\$350,994.62	\$20,646.74	8,058	19,766,702.12	\$ 2,453.05
36800 - Line Transformers	Padmt 11-100 3ph	2006	1,861.00	\$118,305.19	\$63.57	9,919	19,885,007.31	\$ 2,004.74
36800 - Line Transformers	Padmt 101-500 1ph	2006	9	\$39,299.00	\$4,366.56	9,928	19,924,306.31	\$ 2,006.88
36800 - Line Transformers	Padmt 101-500 3ph	2007	100	\$1,382,687.00	\$13,826.87	10,028	21,306,993.31	\$ 2,124.75

Lowest Average Cost in Sample

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36800 - Line Transformers	Padmt 11-100 1ph	2007	287	\$885,315.09	\$3,084.72	10,315	22,192,308.40	\$ 2,151.46
36800 - Line Transformers	Padmt 501-1500 3ph	2007	11	\$332,513.78	\$30,228.53	10,326	22,524,822.18	\$ 2,181.37
36800 - Line Transformers	Padmt 1501+ 3ph	2007	7	\$238,515.05	\$34,073.58	10,333	22,763,337.23	\$ 2,202.97
36800 - Line Transformers	Padmt 11-100 3ph	2007	15	\$127,567.86	\$8,504.52	10,348	22,890,905.09	\$ 2,212.11
36800 - Line Transformers	Padmt 101-500 1ph	2007	6	\$34,009.26	\$5,668.21	10,354	22,924,914.35	\$ 2,214.11
36800 - Line Transformers	Padmt 101-500 3ph	2008	93	\$1,464,601.77	\$15,748.41	10,447	24,389,516.12	\$ 2,334.60
36800 - Line Transformers	Padmt 11-100 1ph	2008	227	\$767,012.11	\$3,378.91	10,674	25,156,528.23	\$ 2,356.80
36800 - Line Transformers	Padmt 501-1500 3ph	2008	7	\$198,083.54	\$28,297.65	10,681	25,354,611.77	\$ 2,373.81
36800 - Line Transformers	Padmt 11-100 3ph	2008	19	\$193,139.17	\$10,165.22	10,700	25,547,750.94	\$ 2,387.64
36800 - Line Transformers	Padmt 1501+ 3ph	2008	3	\$159,845.54	\$53,281.85	10,703	25,707,596.48	\$ 2,401.91
36800 - Line Transformers	Padmt 101-500 1ph	2008	5	\$33,797.47	\$6,759.49	10,708	25,741,393.95	\$ 2,403.94
36800 - Line Transformers	Padmt 101-500 3ph	2009	78	\$1,284,841.48	\$16,472.33	10,786	27,026,235.43	\$ 2,505.68
36800 - Line Transformers	Padmt 11-100 1ph	2009	229	\$838,744.60	\$3,662.64	11,015	27,864,980.03	\$ 2,529.73
36800 - Line Transformers	Padmt 501-1500 3ph	2009	11	\$348,361.74	\$31,669.25	11,026	28,213,341.77	\$ 2,558.80
36800 - Line Transformers	Padmt 1501+ 3ph	2009	5	\$273,171.70	\$54,634.34	11,031	28,486,513.47	\$ 2,582.41
36800 - Line Transformers	Padmt 11-100 3ph	2009	18	\$226,068.08	\$12,559.34	11,049	28,712,581.55	\$ 2,598.66
36800 - Line Transformers	Padmt 101-500 1ph	2009	9	\$66,376.71	\$7,375.19	11,058	28,778,958.26	\$ 2,602.55
36800 - Line Transformers	Padmt 101-500 3ph	2010	98	\$1,515,841.65	\$15,467.77	11,156	30,294,799.91	\$ 2,715.56
36800 - Line Transformers	Padmt 11-100 1ph	2010	231	\$900,839.34	\$3,899.74	11,387	31,195,639.25	\$ 2,739.58
36800 - Line Transformers	Padmt 501-1500 3ph	2010	14	\$391,917.50	\$27,994.11	11,401	31,587,556.75	\$ 2,770.60
36800 - Line Transformers	Padmt 11-100 3ph	2010	15	\$181,754.32	\$12,116.95	11,416	31,769,311.07	\$ 2,782.88
36800 - Line Transformers	Padmt 1501+ 3ph	2010	3	\$146,319.39	\$48,773.13	11,419	31,915,630.46	\$ 2,794.96
36800 - Line Transformers	Padmt 101-500 1ph	2010	12	\$94,599.12	\$7,883.26	11,431	32,010,229.58	\$ 2,800.30
36800 - Line Transformers	Padmt 101-500 3ph	2011	87	\$1,475,044.07	\$16,954.53	11,518	33,485,273.65	\$ 2,907.21
36800 - Line Transformers	Padmt 11-100 1ph	2011	236	\$1,087,382.10	\$4,607.55	11,754	34,572,655.75	\$ 2,941.35
36800 - Line Transformers	Padmt 501-1500 3ph	2011	16	\$708,778.97	\$44,298.69	11,770	35,281,434.72	\$ 2,997.57
36800 - Line Transformers	Padmt 11-100 3ph	2011	17	\$224,871.95	\$13,227.76	11,787	35,506,306.67	\$ 3,012.33
36800 - Line Transformers	Padmt 101-500 1ph	2011	6	\$41,830.79	\$6,971.80	11,793	35,548,137.46	\$ 3,014.34
36800 - Line Transformers	Padmt 1501+ 3ph	2011	1	\$28,105.36	\$28,105.36	11,794	35,576,242.82	\$ 3,016.47
36800 - Line Transformers	Padmt 101-500 3ph	2012	80	\$1,401,766.06	\$17,522.08	11,874	36,978,008.88	\$ 3,114.20
36800 - Line Transformers	Padmt 11-100 1ph	2012	263	\$1,112,020.23	\$4,228.21	12,137	38,090,029.11	\$ 3,138.34

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost	
36800 - Line Transformers	Padmt 501-1500 3ph	2012	15	\$568,961.64	\$37,930.78	12,152	38,658,990.75	\$ 3,181.29	Highest Average Cost in Sample
36800 - Line Transformers	Padmt 1501+ 3ph	2012	3	\$243,794.88	\$81,264.96	12,155	38,902,785.63	\$ 3,200.56	
36800 - Line Transformers	Padmt 11-100 3ph	2012	23	\$224,583.00	\$9,764.48	12,178	39,127,368.63	\$ 3,212.96	
36800 - Line Transformers	Padmt 101-500 1ph	2012	4	\$25,171.41	\$6,292.85	12,182	39,152,540.04	\$ 3,213.97	
36800 - Line Transformers	Padmt 101-500 3ph	2013	75	\$1,138,557.98	\$15,180.77	12,257	40,291,098.02	\$ 3,287.19	
36800 - Line Transformers	Padmt 11-100 1ph	2013	224	\$985,359.28	\$4,398.93	12,481	41,276,457.30	\$ 3,307.14	
36800 - Line Transformers	Padmt 501-1500 3ph	2013	16	\$504,175.82	\$31,510.99	12,497	41,780,633.12	\$ 3,343.25	
36800 - Line Transformers	Padmt 11-100 3ph	2013	13	\$188,788.57	\$14,522.20	12,510	41,969,421.69	\$ 3,354.87	
36800 - Line Transformers	Padmt 1501+ 3ph	2013	3	\$130,222.83	\$43,407.61	12,513	42,099,644.52	\$ 3,364.47	
36800 - Line Transformers	Padmt 101-500 1ph	2013	6	\$52,422.79	\$8,737.13	12,519	42,152,067.31	\$ 3,367.05	
36800 - Line Transformers	Padmt 11-100 1ph	2014	253	\$1,191,197.76	\$4,708.29	12,772	43,343,265.07	\$ 3,393.62	
36800 - Line Transformers	Padmt 101-500 3ph	2014	74	\$1,174,427.40	\$15,870.64	12,846	44,517,692.47	\$ 3,465.49	
36800 - Line Transformers	Padmt 501-1500 3ph	2014	11	\$347,787.15	\$31,617.01	12,857	44,865,479.62	\$ 3,489.58	
36800 - Line Transformers	Padmt 11-100 3ph	2014	17	\$154,037.04	\$9,061.00	12,874	45,019,516.66	\$ 3,496.93	
36800 - Line Transformers	Padmt 1501+ 3ph	2014	3	\$132,557.82	\$44,185.94	12,877	45,152,074.48	\$ 3,506.41	
36800 - Line Transformers	Padmt 101-500 1ph	2014	10	\$43,891.35	\$4,389.14	12,887	45,195,965.83	\$ 3,507.10	
36800 - Line Transformers	Padmt 101-500 3ph	2015	4	\$57,522.17	\$14,380.54	12,891	45,253,488.00	\$ 3,510.47	
36800 - Line Transformers	Padmt 11-100 1ph	2015	10	\$28,833.53	\$2,883.35	12,901	45,282,321.53	\$ 3,509.99	
36800 - Line Transformers	Padmt 501-1500 3ph	2015	1	\$22,946.48	\$22,946.48	12,902	45,305,268.01	\$ 3,511.49	
36800 - Line Transformers	Padmt 11-100 3ph	2015	1	\$6,878.88	\$6,878.88	12,903	45,312,146.89	\$ 3,511.75	
			12,903	\$ 45,312,146.89	\$ 3,511.75				
	Padmt 11-100 1ph		8,330	\$ 15,685,684.06	\$ 1,883.04				
	Padmt 101-500 1ph		219	820,968.05	\$ 3,748.71				
	Padmt 11-100 3ph		2,331	2,852,824.66	\$ 1,223.86				
	Padmt 101-500 3ph		1,694	17,384,448.50	\$ 10,262.37				
	Padmt 501-1500 3ph		252	5,786,718.46	\$ 22,963.17				
	Padmt 1501+ 3ph		77	2,781,503.16	\$ 36,123.42				
			12,903	\$ 45,312,146.89	\$ 3,511.75				
			-	\$ -	-				

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
		1972	37	\$ 17,451.60	\$ 471.66	37	\$ 17,451.60	\$ 471.66
		1973	195	106,720.82	\$ 547.29	232	124,172.42	\$ 535.23
		1974	208	151,897.38	\$ 730.28	440	276,069.80	\$ 627.43
		1975	324	185,355.53	\$ 572.08	764	461,425.33	\$ 603.96
		1976	249	205,691.65	\$ 826.07	1,013	667,116.98	\$ 658.56
		1977	118	111,242.57	\$ 942.73	1,131	778,359.55	\$ 688.20
		1978	516	438,723.22	\$ 850.24	1,647	1,217,082.77	\$ 738.97
		1979	542	435,587.39	\$ 803.67	2,189	1,652,670.16	\$ 754.99
		1980	228	277,352.79	\$ 1,216.46	2,417	1,930,022.95	\$ 798.52
		1981	122	316,807.37	\$ 2,596.78	2,539	2,246,830.32	\$ 884.93
		1982	93	161,957.04	\$ 1,741.47	2,632	2,408,787.36	\$ 915.19
		1983	259	293,511.75	\$ 1,133.25	2,891	2,702,299.11	\$ 934.73
		1984	142	264,381.53	\$ 1,861.84	3,033	2,966,680.64	\$ 978.13
		1985	82	227,905.85	\$ 2,779.34	3,115	3,194,586.49	\$ 1,025.55
		1986	100	197,014.50	\$ 1,970.15	3,215	3,391,600.99	\$ 1,054.93
		1987	161	272,615.34	\$ 1,693.26	3,376	3,664,216.33	\$ 1,085.37
		1988	105	326,653.66	\$ 3,110.99	3,481	3,990,869.99	\$ 1,146.47
		1989	353	758,187.95	\$ 2,147.84	3,834	4,749,057.94	\$ 1,238.67
		1990	170	416,630.12	\$ 2,450.77	4,004	5,165,688.06	\$ 1,290.13
		1991	167	360,679.46	\$ 2,159.76	4,171	5,526,367.52	\$ 1,324.95
		1992	60	210,234.68	\$ 3,503.91	4,231	5,736,602.20	\$ 1,355.85
		1993	178	429,235.52	\$ 2,411.44	4,409	6,165,837.72	\$ 1,398.47
		1994	268	646,612.10	\$ 2,412.73	4,677	6,812,449.82	\$ 1,456.59
		1995	276	793,807.13	\$ 2,876.11	4,953	7,606,256.95	\$ 1,535.69
		1996	312	1,045,452.41	\$ 3,350.81	5,265	8,651,709.36	\$ 1,643.25
		1997	346	1,001,361.91	\$ 2,894.11	5,611	9,653,071.27	\$ 1,720.38
		1998	132	697,108.79	\$ 5,281.13	5,743	10,350,180.06	\$ 1,802.23
		1999	270	839,926.71	\$ 3,110.84	6,013	11,190,106.77	\$ 1,860.99
		2000	275	912,877.23	\$ 3,319.55	6,288	12,102,984.00	\$ 1,924.77
		2001	131	330,474.05	\$ 2,522.70	6,419	12,433,458.05	\$ 1,936.98
		2002	72	243,079.26	\$ 3,376.10	6,491	12,676,537.31	\$ 1,952.94

Utility Account	Retirement Unit	Vint age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
		2003	207	805,130.13	\$ 3,889.52	6,698	13,481,667.44	\$ 2,012.79
		2004	419	1,625,904.44	\$ 3,880.44	7,117	15,107,571.88	\$ 2,122.74
		2005	415	1,554,351.19	\$ 3,745.42	7,532	16,661,923.07	\$ 2,212.15
		2006	2,396	3,262,383.24	\$ 1,361.60	9,928	19,924,306.31	\$ 2,006.88
		2007	426	3,000,608.04	\$ 7,043.68	10,354	22,924,914.35	\$ 2,214.11
		2008	354	2,816,479.60	\$ 7,956.16	10,708	25,741,393.95	\$ 2,403.94
		2009	350	3,037,564.31	\$ 8,678.76	11,058	28,778,958.26	\$ 2,602.55
		2010	373	3,231,271.32	\$ 8,662.93	11,431	32,010,229.58	\$ 2,800.30
		2011	363	3,566,013.24	\$ 9,823.73	11,794	35,576,242.82	\$ 3,016.47
		2012	388	3,576,297.22	\$ 9,217.26	12,182	39,152,540.04	\$ 3,213.97
		2013	337	2,999,527.27	\$ 8,900.67	12,519	42,152,067.31	\$ 3,367.05
		2014	368	3,043,898.52	\$ 8,271.46	12,887	45,195,965.83	\$ 3,507.10
		2015	16	116,181.06	\$ 7,261.32	12,903	45,312,146.89	\$ 3,511.75
			12,903	\$ 45,312,146.89	\$ 3,511.75			
			-	\$ -				

midpoint 6,452 \$ 22,656,073.45 \$ 1,755.88

- 13 Average Physical Age of Pad Mount Line Transformers
- 8 Weighted Cost Average Age of Pad Mount Line Transformers
- 17 Age of Average Cost of Pad Mount Transformers

Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 368 Pad Mount Transformer Vintage Count & Cost

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36900 - Services	Service 2 Wire	1924	1,117	\$7,802.60	\$6.99	1,117	\$7,802.60	\$ 6.99
36900 - Services	Service 2 Wire	1925	532	\$3,679.89	\$6.92	1,649	\$11,482.49	\$ 6.96
36900 - Services	Service 2 Wire	1926	557	\$3,811.75	\$6.84	2,206	\$15,294.24	\$ 6.93
36900 - Services	Service 2 Wire	1927	884	\$5,703.79	\$6.45	3,090	\$20,998.03	\$ 6.80
36900 - Services	Service 2 Wire	1928	1,345	\$9,019.06	\$6.71	4,435	\$30,017.09	\$ 6.77
36900 - Services	Service 2 Wire	1929	864	\$6,550.78	\$7.58	5,299	\$36,567.87	\$ 6.90
36900 - Services	Service 2 Wire	1930	1,382	\$8,209.88	\$5.94	6,681	\$44,777.75	\$ 6.70
36900 - Services	Service 2 Wire	1931	669	\$3,933.29	\$5.88	7,350	\$48,711.04	\$ 6.63
36900 - Services	Service 2 Wire	1932	432	\$2,380.37	\$5.51	7,782	\$51,091.41	\$ 6.57
36900 - Services	Service 2 Wire	1933	145	\$834.80	\$5.76	7,927	\$51,926.21	\$ 6.55
36900 - Services	Service 2 Wire	1934	251	\$1,580.07	\$6.30	8,178	\$53,506.28	\$ 6.54
36900 - Services	Service 2 Wire	1935	428	\$2,668.14	\$6.23	8,606	\$56,174.42	\$ 6.53
36900 - Services	Service 2 Wire	1936	443	\$2,862.67	\$6.46	9,049	\$59,037.09	\$ 6.52
36900 - Services	Service 2 Wire	1937	517	\$3,755.10	\$7.26	9,566	\$62,792.19	\$ 6.56
36900 - Services	Service 2 Wire	1938	632	\$3,995.87	\$6.32	10,198	\$66,788.06	\$ 6.55
36900 - Services	Service 2 Wire	1939	482	\$3,015.67	\$6.26	10,680	\$69,803.73	\$ 6.54
36900 - Services	Service 2 Wire	1940	327	\$2,116.02	\$6.47	11,007	\$71,919.75	\$ 6.53
36900 - Services	Service 2 Wire	1941	348	\$2,514.29	\$7.22	11,355	\$74,434.04	\$ 6.56
36900 - Services	Service 2 Wire	1942	301	\$2,235.61	\$7.43	11,656	\$76,669.65	\$ 6.58
36900 - Services	Service 2 Wire	1943	113	\$826.95	\$7.32	11,769	\$77,496.60	\$ 6.58
36900 - Services	Service 2 Wire	1944	559	\$3,908.09	\$6.99	12,328	\$81,404.69	\$ 6.60
36900 - Services	Service 2 Wire	1945	596	\$4,121.71	\$6.92	12,924	\$85,526.40	\$ 6.62
36900 - Services	Service 2 Wire	1946	891	\$7,254.27	\$8.14	13,815	\$92,780.67	\$ 6.72
36900 - Services	Service 2 Wire	1947	1,241	\$11,608.12	\$9.35	15,056	\$104,388.79	\$ 6.93
36900 - Services	Service 2 Wire	1948	1,454	\$16,054.41	\$11.04	16,510	\$120,443.20	\$ 7.30
36900 - Services	Service 2 Wire	1949	1,403	\$16,739.20	\$11.93	17,913	\$137,182.40	\$ 7.66
36900 - Services	Service 4 Wire	1949	10	\$301.62	\$30.16	17,923	\$137,484.02	\$ 7.67
36900 - Services	Service 2 Wire	1950	570	\$5,012.61	\$8.79	18,493	\$142,496.63	\$ 7.71
36900 - Services	Service 4 Wire	1950	32	\$862.20	\$26.94	18,525	\$143,358.83	\$ 7.74
36900 - Services	Service 2 Wire	1951	394	\$3,679.16	\$9.34	18,919	\$147,037.99	\$ 7.77
36900 - Services	Service 4 Wire	1951	42	\$1,208.18	\$28.77	18,961	\$148,246.17	\$ 7.82

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36900 - Services	Service 2 Wire	1952	386	\$3,824.89	\$9.91	19,347	\$152,071.06	\$ 7.86
36900 - Services	Service 4 Wire	1952	47	\$1,447.02	\$30.79	19,394	\$153,518.08	\$ 7.92
36900 - Services	Service 2 Wire	1953	548	\$5,019.34	\$9.16	19,942	\$158,537.42	\$ 7.95
36900 - Services	Service 4 Wire	1953	72	\$2,055.24	\$28.55	20,014	\$160,592.66	\$ 8.02
36900 - Services	Service 2 Wire	1954	331	\$3,229.97	\$9.76	20,345	\$163,822.63	\$ 8.05
36900 - Services	Service 3 Wire	1954	150	\$4,517.96	\$30.12	20,495	\$168,340.59	\$ 8.21
36900 - Services	Service 4 Wire	1954	62	\$1,898.29	\$30.62	20,557	\$170,238.88	\$ 8.28
36900 - Services	Service 2 Wire	1955	317	\$3,105.49	\$9.80	20,874	\$173,344.37	\$ 8.30
36900 - Services	Service 3 Wire	1955	491	\$14,833.67	\$30.21	21,365	\$188,178.04	\$ 8.81
36900 - Services	Service 4 Wire	1955	78	\$2,417.99	\$31.00	21,443	\$190,596.03	\$ 8.89
36900 - Services	Service 2 Wire	1956	357	\$3,608.00	\$10.11	21,800	\$194,204.03	\$ 8.91
36900 - Services	Service 3 Wire	1956	705	\$21,938.87	\$31.12	22,505	\$216,142.90	\$ 9.60
36900 - Services	Service 4 Wire	1956	96	\$3,357.79	\$34.98	22,601	\$219,500.69	\$ 9.71
36900 - Services	Service 2 Wire	1957	225	\$2,384.33	\$10.60	22,826	\$221,885.02	\$ 9.72
36900 - Services	Service 3 Wire	1957	892	\$29,082.08	\$32.60	23,718	\$250,967.10	\$ 10.58
36900 - Services	Service 4 Wire	1957	98	\$3,325.29	\$33.93	23,816	\$254,292.39	\$ 10.68
36900 - Services	Service 2 Wire	1958	252	\$2,531.87	\$10.05	24,068	\$256,824.26	\$ 10.67
36900 - Services	Service 3 Wire	1958	1,168	\$36,068.40	\$30.88	25,236	\$292,892.66	\$ 11.61
36900 - Services	Service 4 Wire	1958	142	\$4,594.43	\$32.36	25,378	\$297,487.09	\$ 11.72
36900 - Services	Service 2 Wire	1959	280	\$3,009.36	\$10.75	25,658	\$300,496.45	\$ 11.71
36900 - Services	Service 3 Wire	1959	1,425	\$46,954.81	\$32.95	27,083	\$347,451.26	\$ 12.83
36900 - Services	Service 4 Wire	1959	136	\$4,730.84	\$34.79	27,219	\$352,182.10	\$ 12.94
36900 - Services	Service 2 Wire	1960	234	\$2,489.30	\$10.64	27,453	\$354,671.40	\$ 12.92
36900 - Services	Service 3 Wire	1960	1,459	\$47,574.91	\$32.61	28,912	\$402,246.31	\$ 13.91
36900 - Services	Service 4 Wire	1960	135	\$4,681.70	\$34.68	29,047	\$406,928.01	\$ 14.01
36900 - Services	Service 2 Wire	1961	182	\$2,007.62	\$11.03	29,229	\$408,935.63	\$ 13.99
36900 - Services	Service 3 Wire	1961	1,294	\$43,722.36	\$33.79	30,523	\$452,657.99	\$ 14.83
36900 - Services	Service 4 Wire	1961	128	\$4,633.70	\$36.20	30,651	\$457,291.69	\$ 14.92
36900 - Services	Service 2 Wire	1962	139	\$1,621.51	\$11.67	30,790	\$458,913.20	\$ 14.90
36900 - Services	Service 3 Wire	1962	1,290	\$46,000.53	\$35.66	32,080	\$504,913.73	\$ 15.74
36900 - Services	Service 4 Wire	1962	125	\$4,818.93	\$38.55	32,205	\$509,732.66	\$ 15.83

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36900 - Services	Service 2 Wire	1963	121	\$1,432.55	\$11.84	32,326	\$511,165.21	\$ 15.81
36900 - Services	Service 3 Wire	1963	1,400	\$50,705.46	\$36.22	33,726	\$561,870.67	\$ 16.66
36900 - Services	Service 4 Wire	1963	135	\$5,317.74	\$39.39	33,861	\$567,188.41	\$ 16.75
36900 - Services	Service 2 Wire	1964	131	\$1,568.87	\$11.98	33,992	\$568,757.28	\$ 16.73
36900 - Services	Service 3 Wire	1964	1,441	\$52,750.87	\$36.61	35,433	\$621,508.15	\$ 17.54
36900 - Services	Service 4 Wire	1964	128	\$5,137.70	\$40.14	35,561	\$626,645.85	\$ 17.62
36900 - Services	Service 2 Wire	1965	122	\$1,599.89	\$13.11	35,683	\$628,245.74	\$ 17.61
36900 - Services	Service 3 Wire	1965	1,504	\$60,174.55	\$40.01	37,187	\$688,420.29	\$ 18.51
36900 - Services	Service 4 Wire	1965	156	\$6,893.79	\$44.19	37,343	\$695,314.08	\$ 18.62
36900 - Services	Service 2 Wire	1966	126	\$1,665.08	\$13.21	37,469	\$696,979.16	\$ 18.60
36900 - Services	Service 3 Wire	1966	1,730	\$69,702.10	\$40.29	39,199	\$766,681.26	\$ 19.56
36900 - Services	Service 4 Wire	1966	172	\$7,707.86	\$44.81	39,371	\$774,389.12	\$ 19.67
36900 - Services	Service 2 Wire	1967	145	\$2,082.77	\$14.36	39,516	\$776,471.89	\$ 19.65
36900 - Services	Service 3 Wire	1967	1,852	\$81,114.55	\$43.80	41,368	\$857,586.44	\$ 20.73
36900 - Services	Service 4 Wire	1967	160	\$7,856.63	\$49.10	41,528	\$865,443.07	\$ 20.84
36900 - Services	Service 2 Wire	1968	119	\$1,787.91	\$15.02	41,647	\$867,230.98	\$ 20.82
36900 - Services	Service 3 Wire	1968	2,114	\$96,618.09	\$45.70	43,761	\$963,849.07	\$ 22.03
36900 - Services	Service 4 Wire	1968	208	\$10,739.18	\$51.63	43,969	\$974,588.25	\$ 22.17
36900 - Services	Service 2 Wire	1969	112	\$1,732.04	\$15.46	44,081	\$976,320.29	\$ 22.15
36900 - Services	Service 3 Wire	1969	2,357	\$110,821.86	\$47.02	46,438	\$1,087,142.15	\$ 23.41
36900 - Services	Service 4 Wire	1969	224	\$11,980.31	\$53.48	46,662	\$1,099,122.46	\$ 23.55
36900 - Services	Service 2 Wire	1970	122	\$2,042.90	\$16.75	46,784	\$1,101,165.36	\$ 23.54
36900 - Services	Service 3 Wire	1970	2,489	\$126,679.57	\$50.90	49,273	\$1,227,844.93	\$ 24.92
36900 - Services	Service 4 Wire	1970	204	\$11,896.42	\$58.32	49,477	\$1,239,741.35	\$ 25.06
36900 - Services	Service 2 Wire	1971	127	\$2,248.12	\$17.70	49,604	\$1,241,989.47	\$ 25.04
36900 - Services	Service 3 Wire	1971	2,499	\$134,608.36	\$53.86	52,103	\$1,376,597.83	\$ 26.42
36900 - Services	Service 4 Wire	1971	203	\$12,610.38	\$62.12	52,306	\$1,389,208.21	\$ 26.56
36900 - Services	Service 2 Wire	1972	108	\$2,208.92	\$20.45	52,414	\$1,391,417.13	\$ 26.55
36900 - Services	Service 3 Wire	1972	2,284	\$142,020.03	\$62.18	54,698	\$1,533,437.16	\$ 28.03
36900 - Services	Service 4 Wire	1972	201	\$14,516.89	\$72.22	54,899	\$1,547,954.05	\$ 28.20
36900 - Services	Service 2 Wire	1973	85	\$1,867.06	\$21.97	54,984	\$1,549,821.11	\$ 28.19

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36900 - Services	Service 3 Wire	1973	2,148	\$143,000.68	\$66.57	57,132	\$1,692,821.79	\$ 29.63
36900 - Services	Service 4 Wire	1973	175	\$13,624.85	\$77.86	57,307	\$1,706,446.64	\$ 29.78
36900 - Services	Service 2 Wire	1974	70	\$1,890.37	\$27.01	57,377	\$1,708,337.01	\$ 29.77
36900 - Services	Service 3 Wire	1974	1,835	\$150,166.44	\$81.83	59,212	\$1,858,503.45	\$ 31.39
36900 - Services	Service 4 Wire	1974	198	\$19,087.30	\$96.40	59,410	\$1,877,590.75	\$ 31.60
36900 - Services	Service 2 Wire	1975	75	\$2,255.44	\$30.07	59,485	\$1,879,846.19	\$ 31.60
36900 - Services	Service 3 Wire	1975	1,552	\$141,592.91	\$91.23	61,037	\$2,021,439.10	\$ 33.12
36900 - Services	Service 4 Wire	1975	176	\$19,040.50	\$108.18	61,213	\$2,040,479.60	\$ 33.33
36900 - Services	Service 2 Wire	1976	58	\$1,904.58	\$32.84	61,271	\$2,042,384.18	\$ 33.33
36900 - Services	Service 3 Wire	1976	1,744	\$173,515.48	\$99.49	63,015	\$2,215,899.66	\$ 35.16
36900 - Services	Service 4 Wire	1976	186	\$22,104.19	\$118.84	63,201	\$2,238,003.85	\$ 35.41
36900 - Services	Service 2 Wire	1977	69	\$2,460.12	\$35.65	63,270	\$2,240,463.97	\$ 35.41
36900 - Services	Service 3 Wire	1977	1,501	\$161,789.33	\$107.79	64,771	\$2,402,253.30	\$ 37.09
36900 - Services	Service 4 Wire	1977	163	\$21,112.53	\$129.52	64,934	\$2,423,365.83	\$ 37.32
36900 - Services	Service 2 Wire	1978	57	\$2,108.74	\$37.00	64,991	\$2,425,474.57	\$ 37.32
36900 - Services	Service 3 Wire	1978	1,463	\$163,186.77	\$111.54	66,454	\$2,588,661.34	\$ 38.95
36900 - Services	Service 4 Wire	1978	147	\$19,839.12	\$134.96	66,601	\$2,608,500.46	\$ 39.17
36900 - Services	Service 2 Wire	1979	35	\$1,523.41	\$43.53	66,636	\$2,610,023.87	\$ 39.17
36900 - Services	Service 3 Wire	1979	1,358	\$177,682.19	\$130.84	67,994	\$2,787,706.06	\$ 41.00
36900 - Services	Service 4 Wire	1979	134	\$21,365.47	\$159.44	68,128	\$2,809,071.53	\$ 41.23
36900 - Services	Service 2 Wire	1980	41	\$1,786.68	\$43.58	68,169	\$2,810,858.21	\$ 41.23
36900 - Services	Service 3 Wire	1980	1,579	\$206,742.01	\$130.93	69,748	\$3,017,600.22	\$ 43.26
36900 - Services	Service 4 Wire	1980	118	\$18,927.70	\$160.40	69,866	\$3,036,527.92	\$ 43.46
36900 - Services	Service 2 Wire	1981	34	\$1,792.07	\$52.71	69,900	\$3,038,319.99	\$ 43.47
36900 - Services	Service 3 Wire	1981	1,311	\$206,766.95	\$157.72	71,211	\$3,245,086.94	\$ 45.57
36900 - Services	Service 4 Wire	1981	134	\$26,061.90	\$194.49	71,345	\$3,271,148.84	\$ 45.85
36900 - Services	Service 2 Wire	1982	35	\$1,859.61	\$53.13	71,380	\$3,273,008.45	\$ 45.85
36900 - Services	Service 3 Wire	1982	1,331	\$212,134.35	\$159.38	72,711	\$3,485,142.80	\$ 47.93
36900 - Services	Service 4 Wire	1982	111	\$21,943.30	\$197.69	72,822	\$3,507,086.10	\$ 48.16
36900 - Services	Service 2 Wire	1983	24	\$1,275.22	\$53.13	72,846	\$3,508,361.32	\$ 48.16
36900 - Services	Service 3 Wire	1983	1,114	\$185,784.13	\$166.77	73,960	\$3,694,145.45	\$ 49.95

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36900 - Services	Service 4 Wire	1983	84	\$19,406.21	\$231.03	74,044	\$3,713,551.66	\$ 50.15
36900 - Services	Service 2 Wire	1984	50	\$3,596.44	\$71.93	74,094	\$3,717,148.10	\$ 50.17
36900 - Services	Service 3 Wire	1984	1,389	\$209,883.26	\$151.10	75,483	\$3,927,031.36	\$ 52.03
36900 - Services	Service 4 Wire	1984	124	\$33,427.51	\$269.58	75,607	\$3,960,458.87	\$ 52.38
36900 - Services	Service 2 Wire	1985	57	\$6,135.26	\$107.64	75,664	\$3,966,594.13	\$ 52.42
36900 - Services	Service 3 Wire	1985	1,056	\$189,441.95	\$179.40	76,720	\$4,156,036.08	\$ 54.17
36900 - Services	Service 4 Wire	1985	90	\$25,858.84	\$287.32	76,810	\$4,181,894.92	\$ 54.44
36900 - Services	Service 2 Wire	1986	36	\$4,595.15	\$127.64	76,846	\$4,186,490.07	\$ 54.48
36900 - Services	Service 3 Wire	1986	1,026	\$208,633.92	\$203.35	77,872	\$4,395,123.99	\$ 56.44
36900 - Services	Service 4 Wire	1986	96	\$34,852.89	\$363.05	77,968	\$4,429,976.88	\$ 56.82
36900 - Services	Service 2 Wire	1987	27	\$4,123.63	\$152.73	77,995	\$4,434,100.51	\$ 56.85
36900 - Services	Service 3 Wire	1987	869	\$220,942.37	\$254.25	78,864	\$4,655,042.88	\$ 59.03
36900 - Services	Service 4 Wire	1987	78	\$25,117.62	\$322.02	78,942	\$4,680,160.50	\$ 59.29
36900 - Services	Service 2 Wire	1988	34	\$7,493.57	\$220.40	78,976	\$4,687,654.07	\$ 59.36
36900 - Services	Service 3 Wire	1988	901	\$232,131.81	\$257.64	79,877	\$4,919,785.88	\$ 61.59
36900 - Services	Service 4 Wire	1988	83	\$33,740.40	\$406.51	79,960	\$4,953,526.28	\$ 61.95
36900 - Services	Service 2 Wire	1989	25	\$5,709.14	\$228.37	79,985	\$4,959,235.42	\$ 62.00
36900 - Services	Service 3 Wire	1989	809	\$224,645.32	\$277.68	80,794	\$5,183,880.74	\$ 64.16
36900 - Services	Service 4 Wire	1989	84	\$36,137.78	\$430.21	80,878	\$5,220,018.52	\$ 64.54
36900 - Services	Service 2 Wire	1990	33	\$10,371.19	\$314.28	80,911	\$5,230,389.71	\$ 64.64
36900 - Services	Service 3 Wire	1990	807	\$211,786.30	\$262.44	81,718	\$5,442,176.01	\$ 66.60
36900 - Services	Service 4 Wire	1990	84	\$40,455.97	\$481.62	81,802	\$5,482,631.98	\$ 67.02
36900 - Services	Service 2 Wire	1991	45	\$7,197.37	\$159.94	81,847	\$5,489,829.35	\$ 67.07
36900 - Services	Service 3 Wire	1991	713	\$208,450.33	\$292.36	82,560	\$5,698,279.68	\$ 69.02
36900 - Services	Service 4 Wire	1991	90	\$38,833.57	\$431.48	82,650	\$5,737,113.25	\$ 69.41
36900 - Services	Service 2 Wire	1992	37	\$9,316.08	\$251.79	82,687	\$5,746,429.33	\$ 69.50
36900 - Services	Service 3 Wire	1992	723	\$233,804.44	\$323.38	83,410	\$5,980,233.77	\$ 71.70
36900 - Services	Service 4 Wire	1992	71	\$35,370.05	\$498.17	83,481	\$6,015,603.82	\$ 72.06
36900 - Services	Service 2 Wire	1993	26	\$11,196.28	\$430.63	83,507	\$6,026,800.10	\$ 72.17
36900 - Services	Service 3 Wire	1993	607	\$246,270.85	\$405.72	84,114	\$6,273,070.95	\$ 74.58
36900 - Services	Service 4 Wire	1993	57	\$35,848.77	\$628.93	84,171	\$6,308,919.72	\$ 74.95

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36900 - Services	Service 2 Wire	1994	21	\$9,859.15	\$469.48	84,192	\$6,318,778.87	\$ 75.05
36900 - Services	Service 3 Wire	1994	477	\$238,040.28	\$499.04	84,669	\$6,556,819.15	\$ 77.44
36900 - Services	Service 4 Wire	1994	53	\$32,015.49	\$604.07	84,722	\$6,588,834.64	\$ 77.77
36900 - Services	Service 2 Wire	1995	23	\$15,860.06	\$689.57	84,745	\$6,604,694.70	\$ 77.94
36900 - Services	Service 3 Wire	1995	513	\$272,030.97	\$530.27	85,258	\$6,876,725.67	\$ 80.66
36900 - Services	Service 4 Wire	1995	46	\$29,538.49	\$642.14	85,304	\$6,906,264.16	\$ 80.96
36900 - Services	Service 2 Wire	1996	31	\$18,589.41	\$599.66	85,335	\$6,924,853.57	\$ 81.15
36900 - Services	Service 3 Wire	1996	438	\$294,516.39	\$672.41	85,773	\$7,219,369.96	\$ 84.17
36900 - Services	Service 4 Wire	1996	39	\$35,641.36	\$913.88	85,812	\$7,255,011.32	\$ 84.55
36900 - Services	Service 2 Wire	1997	18	\$9,865.16	\$548.06	85,830	\$7,264,876.48	\$ 84.64
36900 - Services	Service 3 Wire	1997	363	\$240,801.58	\$663.37	86,193	\$7,505,678.06	\$ 87.08
36900 - Services	Service 4 Wire	1997	35	\$38,729.42	\$1,106.55	86,228	\$7,544,407.48	\$ 87.49
36900 - Services	Service 2 Wire	1998	19	\$10,022.70	\$527.51	86,247	\$7,554,430.18	\$ 87.59
36900 - Services	Service 3 Wire	1998	340	\$215,007.36	\$632.37	86,587	\$7,769,437.54	\$ 89.73
36900 - Services	Service 4 Wire	1998	34	\$37,731.04	\$1,109.74	86,621	\$7,807,168.58	\$ 90.13
36900 - Services	Service 2 Wire	1999	21	\$11,532.79	\$549.18	86,642	\$7,818,701.37	\$ 90.24
36900 - Services	Service 3 Wire	1999	258	\$199,394.21	\$772.85	86,900	\$8,018,095.58	\$ 92.27
36900 - Services	Service 4 Wire	1999	22	\$31,536.20	\$1,433.46	86,922	\$8,049,631.78	\$ 92.61
36900 - Services	Service 2 Wire	2000	15	\$9,596.36	\$639.76	86,937	\$8,059,228.14	\$ 92.70
36900 - Services	Service 3 Wire	2000	225	\$161,869.44	\$719.42	87,162	\$8,221,097.58	\$ 94.32
36900 - Services	Service 4 Wire	2000	22	\$28,237.22	\$1,283.51	87,184	\$8,249,334.80	\$ 94.62
36900 - Services	Service 2 Wire	2001	5	\$805.00	\$161.00	87,189	\$8,250,139.80	\$ 94.62
36900 - Services	Service 3 Wire	2001	133	\$118,645.45	\$892.07	87,322	\$8,368,785.25	\$ 95.84
36900 - Services	Service 4 Wire	2001	15	\$22,195.79	\$1,479.72	87,337	\$8,390,981.04	\$ 96.08
36900 - Services	Service 2 Wire	2002	29	\$29,752.00	\$1,025.93	87,366	\$8,420,733.04	\$ 96.38
36900 - Services	Service 3 Wire	2002	401	\$331,507.47	\$826.70	87,767	\$8,752,240.51	\$ 99.72
36900 - Services	Service 4 Wire	2002	22	\$39,096.85	\$1,777.13	87,789	\$8,791,337.36	\$ 100.14
36900 - Services	Service 2 Wire	2003	-	\$3,763.52	\$0.00	87,789	\$8,795,100.88	\$ 100.18
36900 - Services	Service 3 Wire	2003	170	\$171,890.38	\$1,011.12	87,959	\$8,966,991.26	\$ 101.95
36900 - Services	Service 4 Wire	2003	11	\$37,446.91	\$3,404.26	87,970	\$9,004,438.17	\$ 102.36
36900 - Services	Service 2 Wire	2004	9	\$18,520.20	\$2,057.80	87,979	\$9,022,958.37	\$ 102.56

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36900 - Services	Service 3 Wire	2004	103	\$327,039.32	\$3,175.14	88,082	\$9,349,997.69	\$ 106.15
36900 - Services	Service 4 Wire	2004	7	\$31,919.70	\$4,559.96	88,089	\$9,381,917.39	\$ 106.50
36900 - Services	Service 2 Wire	2005	-	\$4,186.75	\$0.00	88,089	\$9,386,104.14	\$ 106.55
36900 - Services	Service 3 Wire	2005	113	\$259,928.80	\$2,300.25	88,202	\$9,646,032.94	\$ 109.36
36900 - Services	Service 4 Wire	2005	11	\$30,772.00	\$2,797.45	88,213	\$9,676,804.94	\$ 109.70
36900 - Services	Service 2 Wire	2006	3	\$4,100.63	\$1,366.88	88,216	\$9,680,905.57	\$ 109.74
36900 - Services	Service 3 Wire	2006	128	\$393,605.02	\$3,075.04	88,344	\$10,074,510.59	\$ 114.04
36900 - Services	Service 4 Wire	2006	23	\$61,397.30	\$2,669.45	88,367	\$10,135,907.89	\$ 114.70
36900 - Services	Service 2 Wire	2007	4	\$2,154.13	\$538.53	88,371	\$10,138,062.02	\$ 114.72
36900 - Services	Service 3 Wire	2007	93	\$305,732.16	\$3,287.44	88,464	\$10,443,794.18	\$ 118.06
36900 - Services	Service 4 Wire	2007	15	\$78,636.55	\$5,242.44	88,479	\$10,522,430.73	\$ 118.93
36900 - Services	Service 2 Wire	2008	5	\$2,033.46	\$406.69	88,484	\$10,524,464.19	\$ 118.94
36900 - Services	Service 3 Wire	2008	129	\$333,179.24	\$2,582.78	88,613	\$10,857,643.43	\$ 122.53
36900 - Services	Service 4 Wire	2008	10	\$28,041.75	\$2,804.18	88,623	\$10,885,685.18	\$ 122.83
36900 - Services	Service 2 Wire	2009	4	\$2,586.78	\$646.70	88,627	\$10,888,271.96	\$ 122.86
36900 - Services	Service 3 Wire	2009	133	\$396,384.70	\$2,980.34	88,760	\$11,284,656.66	\$ 127.14
36900 - Services	Service 4 Wire	2009	12	\$44,052.94	\$3,671.08	88,772	\$11,328,709.60	\$ 127.62
36900 - Services	Service 2 Wire	2010	4	\$6,355.44	\$1,588.86	88,776	\$11,335,065.04	\$ 127.68
36900 - Services	Service 3 Wire	2010	140	\$330,476.97	\$2,360.55	88,916	\$11,665,542.01	\$ 131.20
36900 - Services	Service 4 Wire	2010	10	\$52,456.58	\$5,245.66	88,926	\$11,717,998.59	\$ 131.77
36900 - Services	Service 2 Wire	2011	2	\$5,472.71	\$2,736.36	88,928	\$11,723,471.30	\$ 131.83
36900 - Services	Service 3 Wire	2011	131	\$91,412.06	\$697.80	89,059	\$11,814,883.36	\$ 132.66
36900 - Services	Service 4 Wire	2011	14	\$25,485.53	\$1,820.40	89,073	\$11,840,368.89	\$ 132.93
36900 - Services	Service 2 Wire	2012	3	\$2,100.02	\$700.01	89,076	\$11,842,468.91	\$ 132.95
36900 - Services	Service 3 Wire	2012	156	\$245,578.15	\$1,574.22	89,232	\$12,088,047.06	\$ 135.47
36900 - Services	Service 4 Wire	2012	19	\$20,202.51	\$1,063.29	89,251	\$12,108,249.57	\$ 135.67
36900 - Services	Service 2 Wire	2013	3	\$12,873.14	\$4,291.05	89,254	\$12,121,122.71	\$ 135.80
36900 - Services	Service 3 Wire	2013	151	\$262,027.19	\$1,735.28	89,405	\$12,383,149.90	\$ 138.51
36900 - Services	Service 4 Wire	2013	19	\$58,288.65	\$3,067.82	89,424	\$12,441,438.55	\$ 139.13
36900 - Services	Service 2 Wire	2014	1	\$152.02	\$152.02	89,425	\$12,441,590.57	\$ 139.13
36900 - Services	Service 3 Wire	2014	143	\$169,953.65	\$1,188.49	89,568	\$12,611,544.22	\$ 140.80

	Retirement	Vint	Vintage		Average	Accum		Accum
Utility Account	Unit	age	Qantity	Vintage Cost	Cost	Quantity	Accum Cost	Average Cost
36900 - Services	Service 4 Wire	2014	15	\$16,556.07	\$1,103.74	89,583	\$12,628,100.29	\$ 140.97
36900 - Services	Service 2 Wire	2015	1	\$1,373.12	\$1,373.12	89,584	\$12,629,473.41	\$ 140.98
36900 - Services	Service 3 Wire	2015	55	\$51,213.45	\$931.15	89,639	\$12,680,686.86	\$ 141.46
36900 - Services	Service 4 Wire	2015	4	\$4,028.38	\$1,007.10	89,643	\$12,684,715.24	\$ 141.50
			89,643	\$ 12,684,715.24	\$ 141.50			
	Service 2 Wire		24,535	\$ 469,086.86	\$ 19.12	24,535	\$469,086.86	\$ 19.12
	Service 3 Wire		59,173	10,734,475.06	\$ 181.41	83,708	11,203,561.92	\$ 133.84
	Service 4 Wire		5,935	1,481,153.32	\$ 249.56	89,643	12,684,715.24	\$ 141.50
			89,643	\$ 12,684,715.24	\$ 141.50			
			-	\$ -				
		1924	1,117	\$ 7,802.60	\$ 6.99	1,117	\$7,802.60	\$ 6.99
		1925	532	3,679.89	\$ 6.92	1,649	11,482.49	\$ 6.96
		1926	557	3,811.75	\$ 6.84	2,206	15,294.24	\$ 6.93
		1927	884	5,703.79	\$ 6.45	3,090	20,998.03	\$ 6.80
		1928	1,345	9,019.06	\$ 6.71	4,435	30,017.09	\$ 6.77
		1929	864	6,550.78	\$ 7.58	5,299	36,567.87	\$ 6.90
		1930	1,382	8,209.88	\$ 5.94	6,681	44,777.75	\$ 6.70
		1931	669	3,933.29	\$ 5.88	7,350	48,711.04	\$ 6.63
		1932	432	2,380.37	\$ 5.51	7,782	51,091.41	\$ 6.57
		1933	145	834.80	\$ 5.76	7,927	51,926.21	\$ 6.55
		1934	251	1,580.07	\$ 6.30	8,178	53,506.28	\$ 6.54
		1935	428	2,668.14	\$ 6.23	8,606	56,174.42	\$ 6.53
		1936	443	2,862.67	\$ 6.46	9,049	59,037.09	\$ 6.52
		1937	517	3,755.10	\$ 7.26	9,566	62,792.19	\$ 6.56
		1938	632	3,995.87	\$ 6.32	10,198	66,788.06	\$ 6.55
		1939	482	3,015.67	\$ 6.26	10,680	69,803.73	\$ 6.54
		1940	327	2,116.02	\$ 6.47	11,007	71,919.75	\$ 6.53
		1941	348	2,514.29	\$ 7.22	11,355	74,434.04	\$ 6.56
		1942	301	2,235.61	\$ 7.43	11,656	76,669.65	\$ 6.58

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
		1943	113	826.95	\$ 7.32	11,769	77,496.60	\$ 6.58
		1944	559	3,908.09	\$ 6.99	12,328	81,404.69	\$ 6.60
		1945	596	4,121.71	\$ 6.92	12,924	85,526.40	\$ 6.62
		1946	891	7,254.27	\$ 8.14	13,815	92,780.67	\$ 6.72
		1947	1,241	11,608.12	\$ 9.35	15,056	104,388.79	\$ 6.93
		1948	1,454	16,054.41	\$ 11.04	16,510	120,443.20	\$ 7.30
		1949	1,413	17,040.82	\$ 12.06	17,923	137,484.02	\$ 7.67
		1950	602	5,874.81	\$ 9.76	18,525	143,358.83	\$ 7.74
		1951	436	4,887.34	\$ 11.21	18,961	148,246.17	\$ 7.82
		1952	433	5,271.91	\$ 12.18	19,394	153,518.08	\$ 7.92
		1953	620	7,074.58	\$ 11.41	20,014	160,592.66	\$ 8.02
		1954	543	9,646.22	\$ 17.76	20,557	170,238.88	\$ 8.28
		1955	886	20,357.15	\$ 22.98	21,443	190,596.03	\$ 8.89
		1956	1,158	28,904.66	\$ 24.96	22,601	219,500.69	\$ 9.71
		1957	1,215	34,791.70	\$ 28.64	23,816	254,292.39	\$ 10.68
		1958	1,562	43,194.70	\$ 27.65	25,378	297,487.09	\$ 11.72
		1959	1,841	54,695.01	\$ 29.71	27,219	352,182.10	\$ 12.94
		1960	1,828	54,745.91	\$ 29.95	29,047	406,928.01	\$ 14.01
		1961	1,604	50,363.68	\$ 31.40	30,651	457,291.69	\$ 14.92
		1962	1,554	52,440.97	\$ 33.75	32,205	509,732.66	\$ 15.83
		1963	1,656	57,455.75	\$ 34.70	33,861	567,188.41	\$ 16.75
		1964	1,700	59,457.44	\$ 34.97	35,561	626,645.85	\$ 17.62
		1965	1,782	68,668.23	\$ 38.53	37,343	695,314.08	\$ 18.62
		1966	2,028	79,075.04	\$ 38.99	39,371	774,389.12	\$ 19.67
		1967	2,157	91,053.95	\$ 42.21	41,528	865,443.07	\$ 20.84
		1968	2,441	109,145.18	\$ 44.71	43,969	974,588.25	\$ 22.17
		1969	2,693	124,534.21	\$ 46.24	46,662	1,099,122.46	\$ 23.55
		1970	2,815	140,618.89	\$ 49.95	49,477	1,239,741.35	\$ 25.06
		1971	2,829	149,466.86	\$ 52.83	52,306	1,389,208.21	\$ 26.56
		1972	2,593	158,745.84	\$ 61.22	54,899	1,547,954.05	\$ 28.20
		1973	2,408	158,492.59	\$ 65.82	57,307	1,706,446.64	\$ 29.78

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
		1974	2,103	171,144.11	\$ 81.38	59,410	1,877,590.75	\$ 31.60
		1975	1,803	162,888.85	\$ 90.34	61,213	2,040,479.60	\$ 33.33
		1976	1,988	197,524.25	\$ 99.36	63,201	2,238,003.85	\$ 35.41
		1977	1,733	185,361.98	\$ 106.96	64,934	2,423,365.83	\$ 37.32
		1978	1,667	185,134.63	\$ 111.06	66,601	2,608,500.46	\$ 39.17
		1979	1,527	200,571.07	\$ 131.35	68,128	2,809,071.53	\$ 41.23
		1980	1,738	227,456.39	\$ 130.87	69,866	3,036,527.92	\$ 43.46
		1981	1,479	234,620.92	\$ 158.63	71,345	3,271,148.84	\$ 45.85
		1982	1,477	235,937.26	\$ 159.74	72,822	3,507,086.10	\$ 48.16
		1983	1,222	206,465.56	\$ 168.96	74,044	3,713,551.66	\$ 50.15
		1984	1,563	246,907.21	\$ 157.97	75,607	3,960,458.87	\$ 52.38
		1985	1,203	221,436.05	\$ 184.07	76,810	4,181,894.92	\$ 54.44
		1986	1,158	248,081.96	\$ 214.23	77,968	4,429,976.88	\$ 56.82
		1987	974	250,183.62	\$ 256.86	78,942	4,680,160.50	\$ 59.29
		1988	1,018	273,365.78	\$ 268.53	79,960	4,953,526.28	\$ 61.95
		1989	918	266,492.24	\$ 290.30	80,878	5,220,018.52	\$ 64.54
		1990	924	262,613.46	\$ 284.21	81,802	5,482,631.98	\$ 67.02
		1991	848	254,481.27	\$ 300.10	82,650	5,737,113.25	\$ 69.41
		1992	831	278,490.57	\$ 335.13	83,481	6,015,603.82	\$ 72.06
		1993	690	293,315.90	\$ 425.10	84,171	6,308,919.72	\$ 74.95
		1994	551	279,914.92	\$ 508.01	84,722	6,588,834.64	\$ 77.77
		1995	582	317,429.52	\$ 545.41	85,304	6,906,264.16	\$ 80.96
		1996	508	348,747.16	\$ 686.51	85,812	7,255,011.32	\$ 84.55
		1997	416	289,396.16	\$ 695.66	86,228	7,544,407.48	\$ 87.49
		1998	393	262,761.10	\$ 668.60	86,621	7,807,168.58	\$ 90.13
		1999	301	242,463.20	\$ 805.53	86,922	8,049,631.78	\$ 92.61
		2000	262	199,703.02	\$ 762.23	87,184	8,249,334.80	\$ 94.62
		2001	153	141,646.24	\$ 925.79	87,337	8,390,981.04	\$ 96.08
		2002	452	400,356.32	\$ 885.74	87,789	8,791,337.36	\$ 100.14
		2003	181	213,100.81	\$ 1,177.35	87,970	9,004,438.17	\$ 102.36
		2004	119	377,479.22	\$ 3,172.09	88,089	9,381,917.39	\$ 106.50

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
		2005	124	294,887.55	\$ 2,378.13	88,213	9,676,804.94	\$ 109.70
		2006	154	459,102.95	\$ 2,981.19	88,367	10,135,907.89	\$ 114.70
		2007	112	386,522.84	\$ 3,451.10	88,479	10,522,430.73	\$ 118.93
		2008	144	363,254.45	\$ 2,522.60	88,623	10,885,685.18	\$ 122.83
		2009	149	443,024.42	\$ 2,973.32	88,772	11,328,709.60	\$ 127.62
		2010	154	389,288.99	\$ 2,527.85	88,926	11,717,998.59	\$ 131.77
		2011	147	122,370.30	\$ 832.45	89,073	11,840,368.89	\$ 132.93
		2012	178	267,880.68	\$ 1,504.95	89,251	12,108,249.57	\$ 135.67
		2013	173	333,188.98	\$ 1,925.95	89,424	12,441,438.55	\$ 139.13
		2014	159	186,661.74	\$ 1,173.97	89,583	12,628,100.29	\$ 140.97
		2015	60	56,614.95	\$ 943.58	89,643	12,684,715.24	\$ 141.50
			89,643	\$ 12,684,715.24	\$ 141.50			
			-	\$ -				

midpoint 44,822 \$ 6,342,358 \$ 70.75

46	Average Physical Age of Overhead Services Conductor
21	Weighted Cost Average Age of Overhead Services Conductor
23	Age of Average Cost of Overhead Services Conductor

Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 369 Overhead Services Vintage Count & Cost

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36910 - Underground Services	Service 3 Wire	1974	1,081	\$179,720.99	\$166.25	1,081	\$ 179,720.99	\$ 166.25
36910 - Underground Services	Service 3 Wire	1975	1,719	\$384,851.22	\$223.88	2,800	564,572.21	\$ 201.63
36910 - Underground Services	Service 4 Wire	1975	29	\$8,272.97	\$285.27	2,829	572,845.18	\$ 202.49
36910 - Underground Services	Service 3 Wire	1976	2,179	\$513,392.05	\$235.61	5,008	1,086,237.23	\$ 216.90
36910 - Underground Services	Service 4 Wire	1976	91	\$27,310.23	\$300.11	5,099	1,113,547.46	\$ 218.39
36910 - Underground Services	Service 3 Wire	1977	2,156	\$526,958.95	\$244.42	7,255	1,640,506.41	\$ 226.12
36910 - Underground Services	Service 4 Wire	1977	95	\$29,589.97	\$311.47	7,350	1,670,096.38	\$ 227.22
36910 - Underground Services	Service 3 Wire	1978	2,146	\$503,447.68	\$234.60	9,496	2,173,544.06	\$ 228.89
36910 - Underground Services	Service 4 Wire	1978	86	\$25,702.66	\$298.87	9,582	2,199,246.72	\$ 229.52
36910 - Underground Services	Service 3 Wire	1979	2,081	\$574,054.13	\$275.85	11,663	2,773,300.85	\$ 237.79
36910 - Underground Services	Service 4 Wire	1979	104	\$36,551.77	\$351.46	11,767	2,809,852.62	\$ 238.79
36910 - Underground Services	Service 3 Wire	1980	2,006	\$636,670.30	\$317.38	13,773	3,446,522.92	\$ 250.24
36910 - Underground Services	Service 4 Wire	1980	78	\$31,549.94	\$404.49	13,851	3,478,072.86	\$ 251.11
36910 - Underground Services	Service 3 Wire	1981	1,794	\$618,182.89	\$344.58	15,645	4,096,255.75	\$ 261.83
36910 - Underground Services	Service 4 Wire	1981	97	\$42,577.33	\$438.94	15,742	4,138,833.08	\$ 262.92
36910 - Underground Services	Service 3 Wire	1982	1,395	\$512,536.26	\$367.41	17,137	4,651,369.34	\$ 271.42
36910 - Underground Services	Service 4 Wire	1982	86	\$40,243.06	\$467.94	17,223	4,691,612.40	\$ 272.40
36910 - Underground Services	Service 3 Wire	1983	1,467	\$475,253.68	\$323.96	18,690	5,166,866.08	\$ 276.45
36910 - Underground Services	Service 4 Wire	1983	81	\$35,585.06	\$439.32	18,771	5,202,451.14	\$ 277.15
36910 - Underground Services	Service 3 Wire	1984	1,277	\$455,955.60	\$357.05	20,048	5,658,406.74	\$ 282.24
36910 - Underground Services	Service 4 Wire	1984	80	\$26,850.47	\$335.63	20,128	5,685,257.21	\$ 282.46
36910 - Underground Services	Service 3 Wire	1985	981	\$371,315.19	\$378.51	21,109	6,056,572.40	\$ 286.92
36910 - Underground Services	Service 4 Wire	1985	64	\$24,228.63	\$378.57	21,173	6,080,801.03	\$ 287.20
36910 - Underground Services	Service 3 Wire	1986	1,041	\$391,028.14	\$375.63	22,214	6,471,829.17	\$ 291.34
36910 - Underground Services	Service 4 Wire	1986	88	\$38,554.07	\$438.11	22,302	6,510,383.24	\$ 291.92
36910 - Underground Services	Service 3 Wire	1987	1,056	\$443,230.97	\$419.73	23,358	6,953,614.21	\$ 297.70
36910 - Underground Services	Service 4 Wire	1987	89	\$45,782.55	\$514.41	23,447	6,999,396.76	\$ 298.52
36910 - Underground Services	Service 3 Wire	1988	996	\$459,038.95	\$460.88	24,443	7,458,435.71	\$ 305.14
36910 - Underground Services	Service 4 Wire	1988	80	\$47,214.98	\$590.19	24,523	7,505,650.69	\$ 306.07
36910 - Underground Services	Service 3 Wire	1989	950	\$494,115.62	\$520.12	25,473	7,999,766.31	\$ 314.05
36910 - Underground Services	Service 4 Wire	1989	84	\$55,568.64	\$661.53	25,557	8,055,334.95	\$ 315.19

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36910 - Underground Services	Service 3 Wire	1990	1,004	\$547,273.20	\$545.09	26,561	8,602,608.15	\$ 323.88
36910 - Underground Services	Service 4 Wire	1990	106	\$73,950.24	\$697.64	26,667	8,676,558.39	\$ 325.37
36910 - Underground Services	Service 3 Wire	1991	985	\$528,446.13	\$536.49	27,652	9,205,004.52	\$ 332.89
36910 - Underground Services	Service 4 Wire	1991	82	\$55,599.46	\$678.04	27,734	9,260,603.98	\$ 333.91
36910 - Underground Services	Service 3 Wire	1992	1,215	\$607,103.86	\$499.67	28,949	9,867,707.84	\$ 340.87
36910 - Underground Services	Service 4 Wire	1992	97	\$62,224.59	\$641.49	29,046	9,929,932.43	\$ 341.87
36910 - Underground Services	Service 3 Wire	1993	1,269	\$700,097.77	\$551.69	30,315	10,630,030.20	\$ 350.65
36910 - Underground Services	Service 4 Wire	1993	101	\$81,170.48	\$803.67	30,416	10,711,200.68	\$ 352.16
36910 - Underground Services	Service 3 Wire	1994	1,449	\$783,464.30	\$540.69	31,865	11,494,664.98	\$ 360.73
36910 - Underground Services	Service 4 Wire	1994	115	\$94,290.31	\$819.92	31,980	11,588,955.29	\$ 362.38
36910 - Underground Services	Service 3 Wire	1995	1,393	\$849,893.67	\$610.12	33,373	12,438,848.96	\$ 372.72
36910 - Underground Services	Service 4 Wire	1995	104	\$98,899.60	\$950.96	33,477	12,537,748.56	\$ 374.52
36910 - Underground Services	Service 3 Wire	1996	1,613	\$979,370.34	\$607.17	35,090	13,517,118.90	\$ 385.21
36910 - Underground Services	Service 4 Wire	1996	150	\$164,809.27	\$1,098.73	35,240	13,681,928.17	\$ 388.25
36910 - Underground Services	Service 3 Wire	1997	1,599	\$738,814.68	\$462.05	36,839	14,420,742.85	\$ 391.45
36910 - Underground Services	Service 4 Wire	1997	118	\$131,109.02	\$1,111.09	36,957	14,551,851.87	\$ 393.75
36910 - Underground Services	Service 3 Wire	1998	1,631	\$738,140.01	\$452.57	38,588	15,289,991.88	\$ 396.24
36910 - Underground Services	Service 4 Wire	1998	142	\$153,352.14	\$1,079.94	38,730	15,443,344.02	\$ 398.74
36910 - Underground Services	Service 3 Wire	1999	1,373	\$1,160,001.55	\$844.87	40,103	16,603,345.57	\$ 414.02
36910 - Underground Services	Service 4 Wire	1999	102	\$204,609.07	\$2,005.97	40,205	16,807,954.64	\$ 418.06
36910 - Underground Services	Service 3 Wire	2000	1,186	\$804,443.85	\$678.28	41,391	17,612,398.49	\$ 425.51
36910 - Underground Services	Service 4 Wire	2000	75	\$115,626.66	\$1,541.69	41,466	17,728,025.15	\$ 427.53
36910 - Underground Services	Service 3 Wire	2001	735	\$614,733.45	\$836.37	42,201	18,342,758.60	\$ 434.65
36910 - Underground Services	Service 4 Wire	2001	59	\$115,697.66	\$1,960.98	42,260	18,458,456.26	\$ 436.78
36910 - Underground Services	Service 3 Wire	2002	1,863	\$1,287,670.89	\$691.18	44,123	19,746,127.15	\$ 447.52
36910 - Underground Services	Service 4 Wire	2002	153	\$241,813.81	\$1,580.48	44,276	19,987,940.96	\$ 451.44
36910 - Underground Services	Service 3 Wire	2003	1,156	\$950,094.07	\$821.88	45,432	20,938,035.03	\$ 460.87
36910 - Underground Services	Service 4 Wire	2003	88	\$167,491.11	\$1,903.31	45,520	21,105,526.14	\$ 463.65
36910 - Underground Services	Service 3 Wire	2004	1,148	\$1,346,609.49	\$1,173.00	46,668	22,452,135.63	\$ 481.10
36910 - Underground Services	Service 4 Wire	2004	83	\$217,745.67	\$2,623.44	46,751	22,669,881.30	\$ 484.91
36910 - Underground Services	Service 3 Wire	2005	1,170	\$1,238,244.41	\$1,058.33	47,921	23,908,125.71	\$ 498.91

Utility Account	Retirement Unit	Vintage age	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
36910 - Underground Services	Service 4 Wire	2005	72	\$158,014.95	\$2,194.65	47,993	24,066,140.66	\$ 501.45
36910 - Underground Services	Service 3 Wire	2006	1,367	\$1,770,615.32	\$1,295.26	49,360	25,836,755.98	\$ 523.44
36910 - Underground Services	Service 4 Wire	2006	98	\$207,915.48	\$2,121.59	49,458	26,044,671.46	\$ 526.60
36910 - Underground Services	Service 3 Wire	2007	898	\$1,296,554.05	\$1,443.82	50,356	27,341,225.51	\$ 542.96
36910 - Underground Services	Service 4 Wire	2007	90	\$242,980.02	\$2,699.78	50,446	27,584,205.53	\$ 546.81
36910 - Underground Services	Service 3 Wire	2008	887	\$1,317,674.90	\$1,485.54	51,333	28,901,880.43	\$ 563.03
36910 - Underground Services	Service 4 Wire	2008	123	\$309,716.68	\$2,518.02	51,456	29,211,597.11	\$ 567.70
36910 - Underground Services	Service 3 Wire	2009	732	\$1,133,885.22	\$1,549.02	52,188	30,345,482.33	\$ 581.46
36910 - Underground Services	Service 4 Wire	2009	110	\$310,884.02	\$2,826.22	52,298	30,656,366.35	\$ 586.19
36910 - Underground Services	Service 3 Wire	2010	657	\$1,018,481.65	\$1,550.20	52,955	31,674,848.00	\$ 598.15
36910 - Underground Services	Service 4 Wire	2010	121	\$366,624.08	\$3,029.95	53,076	32,041,472.08	\$ 603.69
36910 - Underground Services	Service 3 Wire	2011	749	\$1,024,945.90	\$1,368.42	53,825	33,066,417.98	\$ 614.33
36910 - Underground Services	Service 4 Wire	2011	120	\$346,571.10	\$2,888.09	53,945	33,412,989.08	\$ 619.39
36910 - Underground Services	Service 3 Wire	2012	983	\$1,435,368.39	\$1,460.19	54,928	34,848,357.47	\$ 634.44
36910 - Underground Services	Service 4 Wire	2012	133	\$411,534.83	\$3,094.25	55,061	35,259,892.30	\$ 640.38
36910 - Underground Services	Service 3 Wire	2013	730	\$1,148,584.55	\$1,573.40	55,791	36,408,476.85	\$ 652.59
36910 - Underground Services	Service 4 Wire	2013	103	\$357,895.57	\$3,474.71	55,894	36,766,372.42	\$ 657.79
36910 - Underground Services	Service 3 Wire	2014	697	\$1,163,899.57	\$1,669.87	56,591	37,930,271.99	\$ 670.25
36910 - Underground Services	Service 4 Wire	2014	105	\$178,196.61	\$1,697.11	56,696	38,108,468.60	\$ 672.15
36910 - Underground Services	Service 3 Wire	2015	104	\$153,028.35	\$1,471.43	56,800	38,261,496.95	\$ 673.62
36910 - Underground Services	Service 4 Wire	2015	30	\$44,385.12	\$1,479.50	56,830	38,305,882.07	\$ 674.04
			56,830	\$ 38,305,882.07	\$ 674.04			
	Service 3 Wire		52,918	\$ 32,877,192.19	\$ 621.29	52,918	\$ 32,877,192.19	\$ 621.29
	Service 4 Wire		3,912	5,428,689.88	\$ 1,387.70	56,830	\$ 38,305,882.07	\$ 674.04
			56,830	\$ 38,305,882.07	\$ 674.04			
			-	\$ -				
		1974	1,081	\$ 179,720.99	\$ 166.25	1,081	\$ 179,720.99	\$ 166.25
		1975	1,748	393,124.19	\$ 224.90	2,829	572,845.18	\$ 202.49
		1976	2,270	540,702.28	\$ 238.19	5,099	1,113,547.46	\$ 218.39

Utility Account	Retirement Unit	Vintage	Vintage Quantity	Vintage Cost	Average Cost	Accum Quantity	Accum Cost	Accum Average Cost
		1977	2,251	556,548.92	\$ 247.25	7,350	1,670,096.38	\$ 227.22
		1978	2,232	529,150.34	\$ 237.07	9,582	2,199,246.72	\$ 229.52
		1979	2,185	610,605.90	\$ 279.45	11,767	2,809,852.62	\$ 238.79
		1980	2,084	668,220.24	\$ 320.64	13,851	3,478,072.86	\$ 251.11
		1981	1,891	660,760.22	\$ 349.42	15,742	4,138,833.08	\$ 262.92
		1982	1,481	552,779.32	\$ 373.25	17,223	4,691,612.40	\$ 272.40
		1983	1,548	510,838.74	\$ 330.00	18,771	5,202,451.14	\$ 277.15
		1984	1,357	482,806.07	\$ 355.79	20,128	5,685,257.21	\$ 282.46
		1985	1,045	395,543.82	\$ 378.51	21,173	6,080,801.03	\$ 287.20
		1986	1,129	429,582.21	\$ 380.50	22,302	6,510,383.24	\$ 291.92
		1987	1,145	489,013.52	\$ 427.09	23,447	6,999,396.76	\$ 298.52
		1988	1,076	506,253.93	\$ 470.50	24,523	7,505,650.69	\$ 306.07
		1989	1,034	549,684.26	\$ 531.61	25,557	8,055,334.95	\$ 315.19
		1990	1,110	621,223.44	\$ 559.66	26,667	8,676,558.39	\$ 325.37
		1991	1,067	584,045.59	\$ 547.37	27,734	9,260,603.98	\$ 333.91
		1992	1,312	669,328.45	\$ 510.16	29,046	9,929,932.43	\$ 341.87
		1993	1,370	781,268.25	\$ 570.27	30,416	10,711,200.68	\$ 352.16
		1994	1,564	877,754.61	\$ 561.22	31,980	11,588,955.29	\$ 362.38
		1995	1,497	948,793.27	\$ 633.80	33,477	12,537,748.56	\$ 374.52
		1996	1,763	1,144,179.61	\$ 649.00	35,240	13,681,928.17	\$ 388.25
		1997	1,717	869,923.70	\$ 506.65	36,957	14,551,851.87	\$ 393.75
		1998	1,773	891,492.15	\$ 502.82	38,730	15,443,344.02	\$ 398.74
		1999	1,475	1,364,610.62	\$ 925.16	40,205	16,807,954.64	\$ 418.06
		2000	1,261	920,070.51	\$ 729.64	41,466	17,728,025.15	\$ 427.53
		2001	794	730,431.11	\$ 919.94	42,260	18,458,456.26	\$ 436.78
		2002	2,016	1,529,484.70	\$ 758.67	44,276	19,987,940.96	\$ 451.44
		2003	1,244	1,117,585.18	\$ 898.38	45,520	21,105,526.14	\$ 463.65
		2004	1,231	1,564,355.16	\$ 1,270.80	46,751	22,669,881.30	\$ 484.91
		2005	1,242	1,396,259.36	\$ 1,124.20	47,993	24,066,140.66	\$ 501.45
		2006	1,465	1,978,530.80	\$ 1,350.53	49,458	26,044,671.46	\$ 526.60
		2007	988	1,539,534.07	\$ 1,558.23	50,446	27,584,205.53	\$ 546.81

Utility Account	Retirement Unit	Vint age	Vintage	Vintage Cost	Average	Accum	Accum Cost	Accum
			Quantity		Cost	Quantity		Average
								Cost
		2008	1,010	1,627,391.58	\$ 1,611.28	51,456	29,211,597.11	\$ 567.70
		2009	842	1,444,769.24	\$ 1,715.88	52,298	30,656,366.35	\$ 586.19
		2010	778	1,385,105.73	\$ 1,780.34	53,076	32,041,472.08	\$ 603.69
		2011	869	1,371,517.00	\$ 1,578.27	53,945	33,412,989.08	\$ 619.39
		2012	1,116	1,846,903.22	\$ 1,654.93	55,061	35,259,892.30	\$ 640.38
		2013	833	1,506,480.12	\$ 1,808.50	55,894	36,766,372.42	\$ 657.79
		2014	802	1,342,096.18	\$ 1,673.44	56,696	38,108,468.60	\$ 672.15
		2015	134	197,413.47	\$ 1,473.23	56,830	38,305,882.07	\$ 674.04
			56,830	\$ 38,305,882.07	\$ 674.04			
			-	\$ -				

midpoint 28,415 \$ 19,152,941.04 \$ 337.02

23	Average Physical Age of Underground Services Conductor
13	Weighted Cost Age of Underground Services Conductor
23	Average Cost Age of Underground Services Conductor

Source: PP, Assets, Query, BookCost/monthly Activity/Basis Cost, Saved Queries: Dist 369 Underground Services Vintage Count & Cost

Account 364 Information		
Year for the study to take place in:		2015

A	Average Age (years)	41.0
B	Minimum size pole	35C5
C	Installed Cost of Minimum size pole of age "a"	\$145.58
D	Number of streetlights on separate poles	23158.5
E	Number of area lights on separate poles	11325.6
F	Total number of poles in 364	168,009
G	Total Value in 364	\$67,912,729.11

Dollar Allocations

Streetlighting (DSL) = D*C	\$3,371,398
Area Lighting (DAL) = E*C	\$1,648,773
Customer Component (DPCC) = (F-D-E)*C	\$19,438,461
Demand Component (DPDC) = G -DSL-DAL-DPCC	\$43,454,097

Calculation Note:

Assume Percentage of street lights are on separate poles from the primary system.	75%	Mod	GIS data is not available at this time to confirm at this time - This is a modifier to "D"
Assume Percentage of Area lights are on separate poles from the primary system.	60%	Mod	GIS data is not available at this time to confirm at this time - This is a modifier to "E"

RAW Data

Type	Quantity	Book Cost

SME	Comments

Display	Average age of the account assets giveng by accounting Minimum distribution pole installed by design, standard or code Represents the cost to install the minimum sized pole in the system
Display	This is the number of street lights in the system according to the Asset Records. This is the number of area lights in the system according to the Asset Records. Area lights are private lights. This is the number of poles in the Distribution account 364 according to Asset Records
Calculation	This determines the Dollars Allocated to Street Lighting
Calculation	This determines the Dollars Allcated to Area Lighting
Calculation	This determines the Dollars Allocated to Primary Customer Category
Calculation	This deterimines the Dollars Allocated to Primary Demand Category

C-TRUSS	5	\$2,093.81
EASEMENT	422	\$202,321.78
Non Unitized	55	\$152,236.58
POLE	168009	\$57,464,965.61
XARM	187936.48	\$10,091,111.33
	356,427	\$67,912,729.11

input

input

input

input

input

input

Display

Display

Display

Display

Display

Display

Display of accounting entry to show data

Display of accounting entry to show data

Display of accounting entry to show data

Display of accounting entry to show data

Display of accounting entry to show data

Display of accounting entry to show data

Calculation

Calculation to determine total book cost for the account 364

Work Order estimate Poles account	\$29,392
Number of poles in length of primary	30
Cost to install average pole	\$980
Adjusted Cost per service	\$145.58

Work order estimates OH primary, pole costs

Work order estimates OH primary, number of poles used in the 1-mile sample

Calculation in this sheet

Previous: Cost per service in 1970: 205.98, Not sure what the relavance of this is?

Previous: Cost per service in 1970: 205.98, Not sure what the relavance of this is?

Handy-Whitman Factors	Factors		
Year of Study average for Distribution Plant	673	Average Age	Year
Average of Poles - factor	100	41.00	1974

Year end:

2015

Account 365

SME

Primary

	Distribution Circuit miles	5,280.00	
a	Average Age of Primary Conductor	39.00	
b	Minimum Size primary Unit	1/0R	Display
c	Average Installed cost of Primary Unit of age "a"	\$1,406.61	Display
d	Average number of poles in minimum size primary unit of primary conductor	30	Display
e	Total \$ in account 365 considered to be primary	\$28,963,557	Display
f	Total number of poles used for primary distribution. (Number of poles in Account 364 - Number of poles allocated to streetlighting and area lighting.)	133,524.9	Calculation

Secondary

a	Average Age of Secondary Conductor	39.00	
b	Minimum Size primary Unit	3000	
c	Average Installed cost of secondary Unit of age A	\$1,274.24	Display
d	Number of units of secondary conductor (see note).	2,300	Calculation
e	Total dollars in Account 365 considered secondary. (All conductor not primary - see primary section.)	\$15,813,590	Display
f	Dollar value of duplex conductor in Account 365. (Duplex assumed to be used entirely for street and area lights.)	\$3,162,184	Display
g	Percent of total number of lighting units (street and area lights) that are streetlights.	67%	Calculation

Primary Dollar Allocations

Unit of primary distribution (UPD)= f/d	4,451	Calculation
Customer component (DPCC) = C*UPD	\$ 6,260,573	Calculation
Demand Component (DPDC) = E-DPCC	\$ 22,702,984	Calculation
	28,968,008	

Secondary Dollar Allocations

Streetlighting (DSL) = F*G	\$2,123,629	Calculation
Area Lighting (DAL) = F-DSL	\$1,038,555	Calculation
	\$3,162,184	

Lighting	Customer Component (DSCC) = C*D	\$2,930,343	Calculation Calculation
	Demand Component (DSDC) = E-F-DSCC	\$12,883,247	
		\$15,813,590	

Primary	Account 365 Cost of 1 mile of primary cost	\$6,620	Display calculation
	Primary Conductor cost with applied factor and year	\$1,406.61	

Secondary	Account 365 Secondary Conductor costs	\$5,996.95	Display calculation
	Secondary Conductor cost with applied factor and year	\$1,274.24	

Lighting	WOE conductor for 1-unit sample 22 street lights	\$2,809.74	Display Calculation
	Lighting Conductor Cost with applied factor	\$597.02	

Handy-Whitman Factors		Average Age		Year	
	Year of Study average for Distribution Plant	673			
	Average of Primary - Factor	143	39.00	1976	
	Average age of secondary - Factor	143	39.00	1976	
	Average age of Lighting - Factor	143	39.00	1976	

RAW Data

		Length of Secondary Open wire is divided by 3 to get circuit length				
		Primary	Secondary	Lighting		
Account 365						
	Quantity	Value				
	COND ACSR	8,787,649	\$16,098,803	\$16,098,803		\$0
	COND ALL ALUM	896,217	\$2,467,076	\$2,467,076		\$0
	COND ALUM WP	1,736,007	\$2,403,454	\$1,922,763	642,966	\$480,691
	COND COPPER BARE	833,528	\$512,268	\$512,268		\$0
	COND COPPER BARE 3 STR	0	\$0	\$0		\$0
	COND COPPER WP	2,163,441	\$819,365	\$245,810	1,941,550	\$573,556
	COND COPPERWELD	0	\$0	\$0		\$0
	COND DUPLEX	3,285,588	\$3,158,491			\$3,158,491
	COND DUPLEX 600 V	3,753	\$3,693			\$3,693
	COND IRON	331,456	\$61,091	\$61,091		
	COND QUADRUPLX	430,811	\$1,468,487		430,811	\$1,468,487
	COND TRIPLEX	3,883,708	\$7,601,299		3,883,708	\$7,601,299
	Totals		\$34,594,028	\$21,307,812		\$10,124,032
					6,899,034	\$3,162,184

Total Account Value of 365	\$34,594,028			
Add other material		\$7,655,745.18	\$5,689,558.47	
		\$28,963,557	\$15,813,590	\$3,162,184
Account Total	\$47,939,331			

Primary Multipliers		
ACSR	100%	
Bare Copper	100%	
Aluminum	100%	
Iron Wire	100%	
WP Copper	30%	Estimated to weigh 260lb/1000 ft
WP Aluminum	80%	Estimated to weigh 180lb/1000 ft
Steel	50%	

NOTE: All bare copper, aluminum, ACSR and iron wire are primary. 30% of WP copper, 80% of WP aluminum and 50% of the steel wire are primary. (Estimated by ED Department - exact percentages very difficult to determine.) All miscellaneous conductor and other equipment are primary.

Complete Account 365 Data			Primary	Secondary
Type	Quantity	Book Cost		
ARRESTERS	538	\$105,557.53	\$105,557.53	
AUTO BOOSTER	0	\$0.00		
CAPACITOR BANK	0	\$0.00		
CIRCUIT SWITCH	0	\$0.00		
CIRCUIT SWITCHER	0	\$0.00		
COND ACSR	8787649	\$16,098,803.32		
COND ALL ALUM	896217	\$2,467,076.00		
COND ALUM WP	1736007	\$2,403,454.14		
COND COPPER BARE	833528	\$512,268.45		
COND COPPER BARE 3 STR	0	\$0.00		
COND COPPER WP	2163441	\$819,365.02		
COND COPPERWELD	0	\$0.00		
COND DUPLEX	3285588.4	\$3,158,491.31		
COND DUPLEX 600 V	3753	\$3,692.51		
COND IRON	331456	\$61,091.38		
COND QUADRUPLX	430811	\$1,468,486.71		
COND TRIPLEX	3883708	\$7,601,298.82		
CUTOUTS	2626	\$522,116.43	\$522,116.43	
FAULT INDICATOR	42	\$20,364.26		
INSULATED GUY STRAIN INSULATOR	10	\$1,316.52		
INSULATOR	401835	\$10,941,458.60	\$5,251,900.13	\$5,689,558.47
INTERRUPT SWITCH	0	\$0.00		
MOTOR OPERAT SW	0	\$0.00	\$0.00	
MOTOR OPERATOR	13	\$37,077.27	\$37,077.27	
NON UNITIZED	53	\$240,525.25		
OIL SWITCH	0	\$0.00		
POLE TOP SWITCH	0	\$0.00		
RECLOSER	73	\$316,147.68	\$316,147.68	
RECLOSERS	0	\$0.00	\$0.00	
SECTIONALIZERS	15	\$144,069.08	\$144,069.08	
SWITCH OPERATOR	0	\$0.00		
SWITCHES POLE TOP	481	\$1,278,877.06	\$1,278,877.06	
	22,757,844	\$48,201,537.34		
			\$7,655,745.18	\$5,689,558.47
Insulators considered to be 48% primary and 52% secondary				

Account 366

Type	Quantity	Book Cost
CONDUIT	0	\$0.00
	0	\$0.00

Not applicable

This page will most likely not be part of the calculation as we do not track conduit

Year for the study to take place in: 2015

Account 367SME

Primary

a	Average age of primary unit.	21
b	Minimum size primary unit	10J15
c	Average installed cost of a minimum size primary unit of the age in "A.	\$15,692.45
d	Number of feet of conductor in the minimum size primary unit.	5280
e	Total dollars in Account 367 considered primary. (All conductor rated 5 kv and above, and all nonconductor items are considered primary.)	\$58,799,355.12
f	Total number of feet of primary conductor in Account 367.	15,142,579

display

display

calculation

Secondary

a	Average Age of Secondary unit	21
b	Minimum Size Secondary Unit	10TX6
c	Average Installed cost of secondary Unit of age A	\$7,636.95
d	Number of feet of secondary conductor in minimum size unit	4899
e	Total \$ in Account 367 considered secondary (All conductor rated 600 volts or less is secondary.)	\$7,881,404
f	Total number of feet of secondary conductor in account 367	2,717,215
g	Dollar value of duplex conductor in Account 367 (duplex conductor is assumed to be used entirely for street and area lights).	\$2,491,718
H	Percent of total number of lighting units (street and area lights) that is streetlights.	90.00%

Includes all quadruplex and triplex cable and 1/3 of 600 volt single wire. (Duplex is for lighting only.)

display

display

0

display

display

display

GIS

Primary

Units of Primary Distribution (UPD)=F/D	2,868
Customer Component (DPCC) = C*UPD	\$45,004,581
Demand Component(DPDC) = E-DPCC	\$13,794,775

calculation

calculation

calculation

Secondary

Units of Secondary Distribution (USD) = F/D	555
Streetlighting DSL = G*H	\$2,242,546
Area Lighting DAL = G-DSL	\$249,172
Customer Component (DSCC) = C*USD	\$4,235,809
Demand Component (DSDC) = E-DSCC	\$3,645,594

calculation

calculation

calculation

calculation

calculation

RAW Data					
Type	Quantity	Book Cost	Primary	Secondary	Lighting
COND ALL ALUM	13620	\$69,861	\$69,861		
COND ALUM	15122658.95	\$50,447,965	\$50,447,965		
0	0	\$0	\$0		
0	0	\$0	\$0		
COND ALUM 600 V 1 COND	1009544	\$2,104,184		\$2,104,184	
COND COPPER BARE	3594	\$3,314	\$3,314		
COND DUPLEX	665	\$332			\$332

COND DUPLEX 600 V	1715436	\$2,491,386			\$2,491,386
COND QUADRUPLEx 600 V	6350	\$25,605		\$25,605	
COND TRIPLEX	3685	\$10,025		\$10,025	
COND TRIPLEX 15 KV	2706	\$16,309	\$16,309		
COND TRIPLEX 600 V	2370665	\$5,741,590		\$5,741,590	
Totals	20,248,924	\$60,910,571	\$50,537,449	\$7,881,404	\$2,491,718
Ft of Primary	15,142,579				
Ft of Secondary	2,717,215				
Ft of lighting	1,716,101				
	19,575,895				

All conductor rated 5 kv and above, and all nonconductor items are considered primary
All conductor rated 600 volts or less is secondary.
(duplex conductor is assumed to be used entirely for street and area lights).

Notes

Type	Quantity	Book Cost
ARRESTERS	16,605	2,517,746
COND ALL ALUM	13,620	69,861
COND ALUM	15,122,659	50,447,965
	0	0
	0	0
COND ALUM 600 V 1 COND	1,009,544	2,104,184
COND COPPER BARE	3,594	3,314
COND DUPLEX	665	332
COND DUPLEX 600 V	1,715,436	2,491,386
COND QUADRUPLX 600 V	6,350	25,605
COND TRIPLEX	3,685	10,025
COND TRIPLEX 15 KV	2,706	16,309
COND TRIPLEX 600 V	2,370,665	5,741,590
CUTOUTS	14,411	2,492,273
EASEMENT	149	9,012
ENCLOSURE	390	524,166
FAULT INDICATOR	849	235,003
NON UNITIZED	59	1,388,563
RECLOSERS	3	116,597
SPEC. EQUIPMENT	0	0
SPECIAL EQUIP	0	0
SWITCHES LOAD BREAK	88	978,546
	20,281,477	\$69,172,476.70

Primary

Work Order estimate (12/10/04)

Account 367 Cost of 1 mile of primary in 2014 \$	\$37,989
Primary Conductor cost in Average Age Year	\$15,692.45

Display
calculation

Secondary

Account 367 Secondary Conductor costs	\$18,488.01
Secondary Conductor cost in Average Age Year	\$7,636.95

Display
calculation

Lighting

Lighting Conductor Cost in Average Age Year	\$926,341.41

Handy-Whitman Factors

Year of Study average for Distribution Plant	673	Average Age	Year
Average of Primary - Factor	278	21.00	1994
Average age of secondary - Factor	278	21.00	1994
Average age of Lighting - Factor	278	21.00	1994

Year of Study:

2015

SME

Account 368

All classified secondary

Aged like other accounts

A.	Average installed cost of minimum size 2400 V. overhead unit.*	\$427.66
B.	Average installed cost of minimum size 7200 V. overhead unit.*	
C.	Average installed cost of minimum size 14400 V. overhead unit.*	
D.	Average installed cost of minimum size 2400 V. underground unit.*	\$1,257.53
E.	Average installed cost of minimum size 7200 V. underground unit.*	
F.	Number of 2400 V. overhead units in the account.	34,401
G.	Number of 7200 V. overhead units in the account.	
H.	Number of 14400 V. overhead units in the account.	
I.	Number of 2400 V. underground units in the account.	12,832
J.	Number of 7200 V. underground units in the account.	
K.	Total dollar value of Account 368.	\$85,366,296.45

*Overhead unit cost includes cost of appropriate cutout and arrester.

Customer Component (DSCC) = (A*F)+(B*G)+(C*H)+(D*I)+(E*J)
Demand Component (DSDC) = K- DSDC

\$30,848,675.92
\$54,517,620.53

display

calculation

calculation

RAW Data

Type	Quantity	Book Cost
PADMT 101-500 1PH	220	\$822,720
PADMT 101-500 3PH	1673	\$16,809,189
PADMT 11-100 1PH	8285	\$15,078,181
PADMT 11-100 3PH	2328	\$2,797,351
PADMT 1501+ 3PH	78	\$2,800,840
PADMT 501-1500 3PH	248	\$5,641,367

POLEMT 0-10 1PH	6640	\$3,636,770	
POLEMT 101-500 1PH	250	\$464,301	
POLEMT 101-500 3PH	0	\$0	
POLEMT 11-100 1PH	27509	\$28,006,432	
POLEMT 1501+ 3PH	0	\$0	
POLEMT 501-1500 1PH	0	\$0	
POLEMT 501-1500 3PH	0	\$0	
			\$76,057,149.11
Total Padmounts		\$43,949,646.67	
1ph units 11-100		\$15,078,180.52	
Total 1PH units		\$15,900,900.53	
3PH		\$28,048,746.14	
Total Polemounts		\$32,107,502.44	
0-100 kva units 1ph		\$31,643,201.21	
101-500 kva 1 ph units		\$464,301.23	

Type	Quantity	Book Cost
ARRESTER-CUTOUT	0	\$0
ARRESTERS	39421	\$2,986,956
AUTO 0-10	0	\$0
AUTO 11-100	0	\$0
AUTOBOOSTER	3	\$4,205
CAPACITOR	875	\$923,495
CAPACITOR CONTROL	0	\$0

CAPACITOR BANK	4	\$414
CUTOUTS	41419	\$3,795,364
LINE PROTECTOR	0	\$0
NON UNITIZED	65	\$1,244,115
OIL SWITCHES	0	\$0
PADMT 101-500 1PH	220	\$822,720
PADMT 101-500 3PH	1673	\$16,809,189
PADMT 11-100 1PH	8285	\$15,078,181
PADMT 11-100 3PH	2328	\$2,797,351
PADMT 1501+ 3PH	78	\$2,800,840
PADMT 501-1500 3PH	248	\$5,641,367
POLEMT 0-10 1PH	6640	\$3,636,770
POLEMT 101-500 1PH	250	\$464,301
POLEMT 101-500 3PH	0	\$0
POLEMT 11-100 1PH	27509	\$28,006,432
POLEMT 11-100 3PH	2	\$6,237
POLEMT 1501+ 3PH	0	\$0
POLEMT 501-1500 1PH	0	\$0
POLEMT 501-1500 3PH	0	\$0
POTENTIAL TRANS	0	\$0
RECLOSER	0	\$0
REGULATOR	34	\$233,434
SELF-REG 1-100	0	\$0
STATION TRANSFORMER	89	\$114,927
TRANSFORMER	0	\$0
TRANSFORMER AUTO	0	\$0
	129,143	\$85,366,296.45

Total pole mount XFMRs	34,401
Total Padmount XFMRs	12,832

Work Order estimate

Polemount Cost per xfmr	\$1,390
Adjusted Cost per service	\$427.66

Padmount Cost per xfmr	\$2,497
Adjusted Cost per service	\$1,257.53

Handy-Whitman Factors

Year of Study average for Distribution Plant	673

Average Polemount age - Factor	207
Average Padmount age - Factor	339

Age

Average Age	Year	
32	1983	Polemount
13	2002	Padmount

Year of Study: 2015

Age of 3 & 4
Wire services

Account 369

- A. Average age of a service.
- B. Minimum size of a service. (100' #2TX)
Average installed cost of a minimum size service
- C. of the age in "A."
- D. Total number of 3 and 4 wire services.
- Dollar value of two-wire services (two-wire
- E. services are considered all customer component).
- F. Total dollar value of Account 369.

46
2TX
\$56.15
65,199
\$467,606.77
\$12,630,691.04

Customer Component (DSCC) = (C*D) + E
Demand Component (DSDC) = F-DSCC

\$4,128,225.45	32.68%
\$8,502,465.59	67.32%

RAW Data

Type	Quantity	Book Cost
SERVICE 2 WIRE	24,537	\$467,607
SERVICE 3 WIRE	59,257	\$10,685,957
SERVICE 4 WIRE	5,942	\$1,477,128
	89,736	\$12,630,691.04

Qty & \$ from account 369, PP - Asset 1115 R
Qty & \$ from account 369, PP - Asset 1115 R
Qty & \$ from account 369, PP - Asset 1115 R

Total O.H. and U.G. Services 146,353

Work Order estimate	\$55,807
Number of services in Work order	96
Cost per service in study year \$	\$581
Cost per service in Average Age Year \$	\$56.15

WOE study for system - number of OH services for study

Handy-Whitman Factors

Year of Study average for Distribution Plant	673
Average Overhead Service age - Factor	65

Average Age	Year
46	1969

Year of Study: 2015

Account 369.1 Underground Services

Average age of \$

Average Plant Age

A.	Average age of an underground service.	23
B.	Minimum size of an underground service.	
C.	Average installed cost of a minimum size three-wire service of the age in "A."	\$443.87
D.	Total number of services in Account 369.1.	56,617
E.	Total dollar value of Account 369.1.	\$37,979,687.21

Customer Component (DSCC) = (C*D)	\$25,130,479
Demand Component (DSDC) = E-DSCC	\$12,849,208

RAW Data

Type	Quantity	Book Cost
EASEMENT	1	\$20
SERVICE 3 WIRE	52732	\$32,605,532
SERVICE 4 WIRE	3885	\$5,374,135
	56,617	\$37,979,687.21

Qty & \$ from account 36910, PP - Asset 1115 Report
Qty & \$ from account 36910, PP - Asset 1115 Report
Qty & \$ from account 36910, PP - Asset 1115 Report

Total Residential customers

102771

Retail Customer, KWH&Electric Rev report - res urban+res rur+cottages

Total U.G. Services	56,617

Work Order estimate CR#41303 (12/10/04)	\$131,548

Number of services in Work order model	96

Cost per service in 2004 \$	\$1,370

Cost per service in 1988 \$	\$443.87

Cost of current installed service
Cost of service adjusted with factor

Handy-Whitman Factors

Year of Study average for Distribution Plant	673

Average Underground Service age - Factor	218

Year Installed	Average Age

23	1992

PSC-06.20

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 02/20/2018

Date Due: 03/06/2018

Date of Response: 03/06/2018

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Are OTP's (or OTC's) shareholders willing to fund \$200,000 per year for North Dakota economic development? If not, explain fully why not.

Attachments: 0

Response:

OTP has not proposed shareholder funding of economic development in the manner described by this Data Request. OTP is prepared to fund economic development with shareholder support, as demonstrated by OTP's proposed rider mechanism in this case (Super Large General Service Rider¹) and the Company's Economic Development Rider Proposal (Case No. PU-17-238).

As discussed by Mr. Tommerdahl's Direct Testimony, OTP's present proposal for economic development funding would be used to help re-establish a minimal level of utility-directed focus on economic development in the communities OTP serves through additional staff² devoted to those efforts. OTP's request is well below the minimum amount of spending of \$315,557 per year³ that was in place from 1989 to 2008.

In fact, during the 1989 to 2008 timeframe, OTP spent more than the \$315,557 of which the excess was funded by shareholders. This was noted in the Direct testimony of Ms. Bernadeen Brutlag in Case No. PU-08-862, page 20:

15 Q. HOW MUCH HAS OTP ACTUALLY SPENT ON ECONOMIC
16 DEVELOPMENT SINCE 1989?

¹ Tommerdahl Direct at p. 43-44; Prazak Direct at p. 59-63

² Tommerdahl Direct at p. 41

³ Tommerdahl Direct at p. 39-40

17 A. From 1989 through 2007, OTP has spent over \$9.7 million on economic
18 development in North Dakota. Exhibit ____ (BCB-1), Schedule 2, attached to
19 my testimony shows OTP's spending each year for each of the four categories in
20 the Commission's spending guidelines. During this time period, OTP has, on
21 average, spent just over \$500,000 annually.

PSC-08.05

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 03/06/2018
Date Due: 03/20/2018
Date of Response: 03/22/2018
Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

For the purposes of this request, please refer to the file “42 Vol 2b DGP-1 Schedule 2 2018 Marginal Cost Study.xls” provided with the Company’s workpapers. Please refer to sheet “Dist Fac Inv per Cust T13”.

- a. Please reconcile the assumption of 3 percent annual inflation from 2016-2018 in this worksheet with the use of 2 percent in sheet “Ancillary Serv Costs 2018 T9” as referenced in the “Note:” in cell 32 of sheet “Ancillary Serv Costs 2018 T9”.
- b. Please provide all source documents used to create this spreadsheet.
- c. Please provide the documents requested in electronic form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Attachments: 1

Attachment 1 to DR ND-PSC-08.05.xlsx

Response:

- a. OTP uses 3% as the inflation forecast applicable to plant. This is consistent with the inflation rate built into OTP’s most recent 10yr O&M and Routine Capital Budgets as of August 2017. It is also consistent with combined labor and material cost index growth

from 2016 to 2017, estimated from Handy Whitman Index and OTP's labor cost rate in tab W11. For ancillary service costs, we used 2% consistent with the forecast inflation for 2016-2018, as per OECD's CPI forecast (<https://data.oecd.org/price/inflation-forecast.htm#indicator-chart>).

- b. The file that was used to estimate the marginal facilities cost by customer class was prepared in 2015 for the 2015 MN Rate Case. The 2018 study updated those costs by inflation. The file prepared for the 2015 study is attached as Attachment 1 to DR ND-PSC-08.05.
- c. Provided as requested.

PSC-09.06

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 03/09/2018
Date Due: 03/23/2018
Date of Response: 03/23/2018
Responding Witness: Gina Ice, Rate Analyst

Data Request:

Please refer to Table 5 on page 12 of the Direct Testimony of Gina Ice. Please explain how the Company determined to cap the revenue increase to a rate class at 13.70 percent. Please provide all workpapers and source documents. Provide the files in electronic form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Attachments: 1

Attachment 1 to DR ND-PSC-09.6.xlsx

Response:

The Class Cost of Service Study serves as a guide for setting class revenue responsibilities. However, as stated in Gina Ice's Direct Testimony on page 11, "it is necessary to consider other objectives, particularly the objective of maintaining reasonable rate continuity, and mitigating disproportionate or abrupt rate impacts" when determining the percentage of revenue increase to be proposed for each revenue class.

The Company's objective in setting class revenue responsibilities is to generally move all customer classes closer to its CCOSS indicated cost responsibilities. For some classes, this increase may be more or less than others. Otter Tail did not cap the revenue increase to a customer class at 13.7 percent increase as evidenced by the Irrigation customer class having a proposed increase of 19.0 percent. A fair amount of judgement was used when proposing the 13.7 percent increase for many of the customer classes as this percentage achieves the Company's objective in moving customer classes closer to its cost responsibilities while also mitigating the large up or down swings in individual customer classes. This percentage increase maintains a reasonable percent of increase across all customer classes.

Please see Attachment 1 to DR ND-PSC-09.6 for the Excel spreadsheet that was used in determining the proposed class revenue increases.

PSC-09.07

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 03/09/2018

Date Due: 03/23/2018

Date of Response: 03/23/2018

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Please refer to pages 21-22 of the Direct Testimony of Stuart TommerDahl where he discusses the Company's proposed Generation Cost Recovery Rider ("GCRR").

- a. Please explain if the Company will undertake the proposed Astoria Project capital investments if the GCRR is not approved?
- b. Please explain if the Company would be willing to limit or cap the investments that are recovered through the proposed GCRR?
- c. Please explain if the proposed GCRR will terminate after the completion of the Astoria Project.
- d. Please provide the estimated annual rate impacts for each rate class under the proposed GCRR.
- e. Please provide all workpapers and source documents. Provide the files in electronic form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Attachments: 0

Response:

- a. Yes. OTP will be shutting down Hoot Lake Plant in the spring of 2021.
- b. In this case OTP, is not requesting the inclusion of any costs in the GCRR. OTP is only requesting establishment of the rider for future use. Once OTP gets to a point where material costs are being incurred on the Astoria project, OTP will make a separate filing to request Commission approval to include the Astoria project in the GCRR, as well as the associate costs estimated for that project in that filing. OTP believes that proceeding would be the more appropriate time to address the levels of cost recovery.

- c. OTP would propose leaving the tariff in place but simply set the rate to zero once recovery is no longer necessary through the GCRR. If another project is identified at some future time that might qualify for recovery in the GCRR, the mechanism could be more easily be re-established if cost recovery of that new project through is approved by the Commission.
- d. OTP has not yet built the GCRR tracker model to compute the projected annual rate impacts. Per proposed rate schedule 13.06, OTP is proposing a percent of bill rate so all customers across each class would see similar increase
- e. See response to d.

PSC-09.12

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 03/09/2018
Date Due: 03/23/2018
Date of Response: 03/23/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Please refer to page 40 lines 6-7 of the Direct Testimony of Stuart TommerDahl where he states “From 1989 through 2007, OTP assisted in creating 6,222 jobs and assisted in saving an additional 1,069 jobs in North Dakota. During the last year of that plan in 2007, OTP worked with 53 cities in North Dakota that requested assistance. The projects covered a wide variety of business development projects and helped create 451 jobs.”

- a. Please provide annually the number of jobs created and the costs expended by the Company in each year from 1989 to 2007.
- b. Please provide the amount that was recovered from customer during this period (1989-2007) to facilitate economic development in the Company’s North Dakota territory.
- c. To the extent the Company is able, please provide the number of individuals/jobs that are still employed of those identified in part (a).
- d. Please provide all workpapers and source documents. Provide the files in electronic form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Attachments: 2

Attachment 1 to DR ND-PSC-09.12.pdf
Attachment 2 to DR ND-PSC-09.12.pdf

Response:

- a. Attachment 1 to DR ND-PSC-09.12 is a recap of jobs created and jobs saved from 1989 – 2007 across all of OTP jurisdictions. North Dakota amounts are reflected in column C and D.

Attachment 2 to DR ND-PSC-09.12 provides a summary of the North Dakota Economic Development expenditures from 1989 to 2007, as provided in OTP's 2008 general rate case by OTP witness Ms. Bernadeen Brutlag as Exhibit__(BCB-1) Schedule 2. OTP spent approximately \$9.7 million during this time period on Economic Development, averaging \$513,689 per year. In OTP's 1989 rate case Order, OTP included \$315,557 in its test year. Over this time period, OTP spent nearly \$200,000 a year more on average, than was included in base rates.

- b. See response to a.
- c. OTP does not have this information.

PSC-09.12, ATTACHMENT 1

Otter Tail Power Company
Economic Development - Jobs Impact Summary

	A	B	C	D	E	F	G	H
	<u>MN</u>	<u>MN</u>	<u>ND</u>	<u>ND</u>	<u>SD</u>	<u>SD</u>	<u>CREATED</u>	<u>SAVED</u>
1989 CREATED	2.0		121.0		25.0		148.0	
SAVED		9.0		8.0		-		17.0
1990 CREATED	37.0		100.0		166.0		303.0	
SAVED		109.0		29.0		7.0		145.0
1991 CREATED	64.0		196.0		16.0		276.0	
SAVED		117.0		31.0		-		148.0
1992 CREATED	66.0		320.0		115.0		501.0	
SAVED		-		163.0		13.0		176.0
1993 CREATED	644.0		427.0		104.0		1,175.0	
SAVED		316.0		39.0		14.0		369.0
1994 CREATED	796.0		492.0		63.5		1,351.5	
SAVED		186.0		27.0		-		213.0
1995 CREATED	657.0		311.0		37.0		1,005.0	
SAVED		506.0		8.0		-		514.0
1996 CREATED	931.0		328.5		38.0		1,297.5	
SAVED		78.0		100.0				178.0
1997 CREATED	793.0		389.0		194.0		1,376.0	
SAVED		188.0		4.0				192.0
1998 CREATED	628.0		358.5		61.0		1,047.5	
SAVED		183.0		6.0				189.0
1999 CREATED	626.0		366.0		293.0		1,285.0	
SAVED		229.0		38.0				267.0
2000 CREATED	631.0		273.0		57.5		961.5	
SAVED		172.0		5.5				177.5
2001 CREATED	567.0		217.0		126.5		910.5	
SAVED		147.0		6.0				153.0
2002 CREATED	675.0		187.0		67.0		929.0	
SAVED				527.0				527.0
2003 CREATED	378.0		363.5		79.0		820.5	
SAVED		169.0		3.0				172.0
2004 Created	393.0		407.0		64.0		864.0	
Saved				40.0				40.0
2005 Created	511.0		467.0		47.0		1,025.0	
Saved		34.0		2.0				36.0
2006 Created	498.0		448.0		10.0		956.0	
Saved		106.0		33.0		6.0		145.0
2007 Created	551.0		451.0		66.0		1,068.0	
Saved		31.0		-		-		31.0
		<u>MN</u>	<u>ND</u>	<u>ND</u>	<u>SD</u>	<u>SD</u>		
GT/STATES CREATED	9,448.0		6,222.5		1,629.5			
GT/STATES SAVED		2,580.0		1,069.5		40		
GRAND TOTAL OF JOBS CREATED SINCE 1989=							17,300.0	
GRAND TOTAL OF JOBS SAVED SINCE 1989=								3,689.5

PSC-09.14

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 03/09/2018

Date Due: 03/23/2018

Date of Response: 03/23/2018

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Please refer to page 41 line 2 of the Direct Testimony of Stuart Tommerdahl where he states “OTP has included \$200,000 of economic development costs in the 2018 Test Year.”

- a. Please explain and quantify how these economic development costs will directly benefit current ratepayers.
- b. Please explain in detail how the proposed \$200,000 will be used to attract customers to the Company’s service territory.
- c. Please provide all workpapers and source documents. Provide the files in electronic form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Attachments: 0

Response:

- a. From purely a utility perspective, attracting new customers to OTP’s service territory, and increasing the load will generate incremental margin to help cover OTP’s fixed costs. This will help keep rates lower long term and help delay future rate cases as inflationary pressures continue to push costs up. In the case of costs recovered through certain riders such as the Transmission Rider, rates will be lower the next time they are reset as those revenue requirements are spread over more billing determinants than if the new customer wasn’t on the system. Load growth can help other ratepayers both in the near term and long term.
- b. As Mr. Tommerdahl states in his Direct Testimony, OTP will add additional staff for purposes of more intentionally engaging with the communities we serve to support their ongoing efforts to attract and retain businesses that will help their local economies

compete and survive. Specifically, OTP will help increase business development by helping start-ups, expansions, relocations, financing, planning, and other development opportunities. This could involve collaborating with other stakeholders (city, county, state officials and other economic development orientated entities) to collectively work with the entity to address that entity's needs. From a community perspective, OTP 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. These are the types of activities OTP was engaged in from 1989 to 2007.

c. N/A

PSC-10.01

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 03/21/2018

Date Due: 04/04/2018

Date of Response: 04/04/2018

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Please refer to page 39 lines 11-13 of the Direct Testimony of Stuart Tommerdahl where he states “Our efforts also help to ensure that community members have access to health care services and that their children have the same educational opportunities as those who live in larger communities. Our efforts help communities utilize their infrastructure and utility resources more effectively.”

- a. Please explain and provide examples of all instances how the Company ensures that the community members have access to health care services?
- b. Please explain and provide examples of all instances how the Company ensures that children in its community have access to the same educational opportunities?

Attachments: 0

Response:

- a. By attracting new business or assisting existing businesses in creating new job opportunities, 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. As populations decline, the ability for communities to support those essential services becomes more difficult. These efforts align with elements of OTP’s overarching mission and vision statements which read as follows:

OTP's mission statement is: "To produce and deliver electricity as reliably, economically, and environmentally responsibly as possible to the balanced benefit of customers, shareholders, and employees and to improve the quality of life in the areas in which we do business."

OTP's vision statement is: **Growth and Success – for our company and the rural communities we serve.** We collaborate and prosper through responsible, resourceful, action. We balance community, economic, and environmental commitments. **Always.**

- b. See response to a.

PSC-11.20

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/05/2018

Date Due: 04/18/2018

Date of Response: 04/30/2018

Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Please refer to the Company's minimum size system study provided in response to ND-PSC-04.31.

- a. Please explain did the Company make adjustments to account for the load carrying capability of the various distribution plant items that were allocated using the minimum size system approach?
- b. If the response to (a) is affirmative, please explicitly identify where the Company has made these adjustments in its workpapers.

Attachments: 0

Response:

a. OTP has made adjustments to the Distribution Primary Demand Allocation Factor (D3) and the Distribution Secondary Demand Allocation Factor (D4). Both were adjusted downward by the load-carrying capability of the minimum system.

b. These adjustments are made during the process to calculate the historical demand allocation factors. Please see DR ND-PSC-04.25.

PSC-11.23

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/05/2018

Date Due: 04/18/2018

Date of Response: 05/01/2018

Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Please refer to the direct testimony of David G. Prazak, page 9 line 23 through page 10 line 12, where he describes the three modified versions of EPMC methodology.

- a. Please explain why each customer class was assigned its respective EPMC Method.
- b. Please describe the exact calculations used to apply EPMC Method 1 to the rate classes within a customer class.
- c. Please describe what is meant by “a blended variation between Method 1 and a strict application of EPMC within a customer class”.
- d. Please describe the exact calculations used to apply EPMC Method 2 to the rate classes within a customer class.
- e. Please describe what is meant by “an iterative method that uses a blended variation between two rate classes within the Lighting customer class.”
- f. Please describe the exact calculations used to apply EPMC Method 3 to the rate classes within a customer class.

Attachments: 0

Response:

a. Mr. Prazak’s Direct Testimony (pp 7-10) describes the EPMC method (what it is, an example, benefits, and how it was applied). Each customer class was assigned its respective EPMC Method to move rates closer to cost responsibilities. Generally, with each incremental method, more gradualism is required to reduce rate shock yet assign cost responsibilities as much as possible.

b. The response to this data request refers to information presented in Attachment 2 to DR ND-PSC-14.01, tab 100% MC (<20KW) which contains the marginal cost information for small general service.

Step 1. Create a cost of service study with forecasted inputs in order to generate test year revenue requirements. The revenue requirements in turn are functionalized and assigned to revenue classes and then to sub-classes. For the revenue requirement for general service, please see the \$33,960,006.54 in Attachment 2 to DR ND-PSC-14.01.

Step 2. In the Otter Tail request this amount must be reduced by 7.368% because that is the base fuel recovery that is being moved out of base rates into the fuel rider in it's entirety. Moving that portion of fuel recovery out of base rates into the fuel rider lowers the class target revenue to \$31,457,729.

Step 3. Calculate the marginal revenues by applying marginal costs to the billing determinants to create forecasted marginal revenues. From Attachment 2, the result of this process is to calculate the small general service portion of general service at \$6,809,680.32.

Step 4. Here we compare the class revenue target to the forecasted amount to find the efficiency of each sub-class. In this case that is 114% as observed in cell I87.

Step 5. Now allocate the class target revenues from the forecasted COSS using marginal revenue percentage. That is observed in cell F92.

Step 6. Then calculate the percent change by dividing the marginally allocated revenue (step 5) into the forecasted COSS revenue and subtracting from 1. Please refer to cell G92.

Step 7. The result of step 6 is to create the EPMC raw amount. At this point we can move to Method 1 and Method 2.

Method 1 – Take the requested percent change and add to the EMPC raw percent change. Divide that sum by two. Multiply the test year revenue by that percentage plus one. The result is in cell F97.

c. The blended variation combines method 1 and a strict application of marginal cost. For example, consider designing a rate for three sub-classes. One of the sub-classes is closer to marginal cost or as referred to here, more “efficient” than the other two. For the efficient sub-class, the EPMC percent change can be used and method 1 will be applied to allocate the remaining revenue requirement for the other two sub-classes.

d. Please use the first seven steps defined in part b. to this response.

Method 2 – Take the requested change percent and add to the method 1 marginal change percent. Divide that sum by two. Multiply the test year revenue by that percentage plus one. The result is in cell F102.

e. An iterative method that uses a blended variation between two rate classes within the Lighting customer class refers to the situation in rate design when using the first two methods still leaves the percent increase for the sub-classes so far apart that the impact on customers cannot be justified using either of the first two methods. Method 3 utilizes additional analysis and knowledge of the rate itself to minimize the impact of the rate change to the customer group. For example, in the lighting class, when the overall rate class increase was determined to be 1.93% using method 2, the result left us at 18.5% increase for sub-class 1 and -.56% decrease for sub-class 2. Using method 3 mitigates rate shock for the customers by iterating the calculations and subjectively choosing input factors.

f. Method 3 – The exact calculations are the same as for method 1 and 2 as described above. The end result depends on the steps taken in part e to this question. In the attachment 4 to DR ND-PSC-14.01 an example can be seen applied to the lighting class.

Please see the DR ND-PSC-14.01 live spreadsheets in the attachments for detailed calculations.

PSC-13.01

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/13/2018

Date Due: 04/27/2018

Date of Response: 04/27/2018

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

For the purpose of this request please refer to the Company's transmission rate filings with FERC.

- a. Please explain in detail the allocation methodology that the Company uses to allocate its transmission plant in its rate filings with FERC.
- b. Please provide the Company's most recently approved transmission rate filing that was filed with FERC.
- c. Please provide a copy of the FERC order approving the Company's most recent transmission allocations and rate filing.
- d. Please provide all workpapers and source documents in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Attachments: 1

Attachment 1 to ND-PSC-13.01.pdf

Response:

- a. OTP understands this question to refer to OTP's MISO Tariff Attachment O, MM and GG and other related schedules. The Attachment O template is a FERC approved template. OTP's template and rate methodology is consistent with other MISO transmission owners who utilize a forecast test year. Attachment O is a formulaic spreadsheet which allocates specific FERC accounts and associated FERC Form 1 data to

determine the appropriate transmission related investments and expenses necessary to determine the appropriate transmission rates per the MISO tariff. FERC does not annually approve the template. FERC approval is only required if and when changes are made to the template. Absent any changes, the same template is used year after year. Each year, Attachment O and applicable related schedules is completed and submitted to MISO to ultimately determine OTP's respective transmission rates charged during the applicable test year. Footnotes included in Attachment O provide additional explanation of key components of Attachment O.

- b. The most recent approval by FERC of OTP's Attachment O template was in Docket No. ER16-197-00 with the Order issued on December 30, 2015. OTP was a party with a number of MISO Transmission Owners seeking a common update to their respective Attachment O templates. All details of the filing can be found at the FERC website at: https://elibrary.ferc.gov/idmws/docket_search.asp
- c. Attachment 1 to DR ND-PSC-13.01 is a copy of the FERC Order in Docket No. ER16-197-00.
- d. OTP's most recent Attachment O, MM, and GG templates and associated schedules can be found on OTP's MISO Web page at: <https://www.misoenergy.org/markets-and-operations/ts-pricing/to-rate-data/otter-tail-power-company-otp/#t=10&p=0&s=&sd=>

PSC-13.02

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/13/2018
Date Due: 04/27/2018
Date of Response: 04/30/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

For the purpose of this request please refer to the Company's Transmission Planning process.

- a. Please provide a detailed explanation of how the Company plans for transmission plant investments and transmission plant expenses including but not limited to scheduled maintenance, unscheduled outages, diversity, and ability to meet system peak.
- b. Please explain in detail is it the Company's primary objective is to meet its annual system peak on a monthly basis as it relates to transmission plant planning and investments.
- c. If the Company's response to (b) is negative, please explain the Company's primary planning objective as it relates to transmission plant planning and investments.
- d. Please provide all workpapers and source documents in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Attachments: 0

Response:

- a. Otter Tail must meet the applicable requirements of the NERC reliability standards. NERC's Transmission Planning (TPL) standard¹ requires Otter Tail to perform transmission planning studies annually to evaluate how the system will respond during scheduled maintenance, unscheduled outages, different generation dispatches, and various load levels. For example, transmission planning studies must include a model that represents a peak load condition for two of the first five future years and an off-peak load condition for one of the first five future years. Likewise, scheduled maintenance of

¹ See NERC Reliability Standard TPL-001-4 at: <https://www.nerc.com/files/TPL-001-4.pdf>

generation or transmission facilities with a duration of at least six months must be included in the models used for the planning study. Furthermore, the TPL Standard describes how the system must respond to unscheduled outages (classified as events named “P0” through “P7”, which are comprised of a variety of different single element contingencies and multiple element contingencies). Lastly, the TPL standard also requires the annual planning study to determine the impact of extended outages from a major equipment failure requiring a lead time of one year or more to replace the failed equipment.

To the extent that the transmission system does not meet the performance standards outlined in the TPL standard, Otter Tail must develop “corrective action plans” that may include, but are not limited to, new transmission plant investments, new or modified protection schemes, and/or operating procedures.

To comply with NERC’s requirements outlined in the TPL standard, Otter Tail collaborates closely with MISO each year to have them include transmission planning studies of Otter Tail’s transmission system through their annual Transmission Expansion Plan (MTEP).

- b. As described above, the TPL standard require transmission planning studies to include various load levels. Based on past transmission planning studies performed for the Otter Tail transmission system, new transmission plant investments are generally identified in models that represent either peak load conditions or off-peak load conditions. Peak load conditions are generally worst in the winter when Otter Tail experiences the highest loadings on its transmission system. Off-peak load conditions are generally worst in the spring and fall when generation from intermittent resources (i.e. wind) is high and load levels are low. The performance during these most stressed times of the year (peak and off-peak load conditions) generally define the basis for transmission plant planning and investments for Otter Tail.
- c. Otter Tail’s primary transmission planning 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. To meet this objective, Otter Tail’s transmission plant planning and corresponding investments are based on the most limiting condition identified through transmission planning studies. As described above, transmission plant planning is generally based on models that represent winter peak load conditions or off-peak load conditions with high generation levels from intermittent resources.
- d. MISO’s 2017 Transmission Expansion Plan (MTEP17) is the most recent transmission planning study of the Otter Tail transmission system. The performance of Otter Tail’s transmission system and corrective action plans can be found in Appendix D1 of the MTEP17 report.²

² See page 28 of Appendix D1 available at <https://cdn.misoenergy.org/MTEP17%20Appendix%20D1-West106038.pdf>

PSC-13.03

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/13/2018

Date Due: 04/27/2018

Date of Response: 04/24/2018

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Please provide a detailed explanation of the Company's planned system expansion related to its production plant in the next five years.

Attachments: 0

Response:

Otter Tail currently has two production plant projects underway.

First is the Astoria Station, an approximately 250 MW natural gas combustion turbine located in northeastern South Dakota near the town of Astoria, SD. This plant is located at the intersection of the Northern Border natural gas pipeline and the Big Stone South to Brookings 345 KV transmission line. Permitting for the site is well underway and actual physical construction is planned to begin in 2019. It is expected that construction will be substantially completed by the end of 2020 with commercial operation expected early in 2021.

Second is the 150 MW Merricourt wind project located in southeast North Dakota. Construction is currently planned to begin in 2019.

The North Dakota Public Service Commission granted an Advanced Determination of Prudence (ADP) for both projects in October 2017.

The Company continues to evaluate a utility-scale solar project during the next five years. As prices for solar continue to decline, it is expected that a solar project will become part of a least-cost resource mix benefiting all of our customers within the next five years.

PSC-14.01
(NOT PUBLIC)

OTTER TAIL POWER COMPANY

Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/18/2018

Date Due: 05/02/2018

Date of Response: 05/02/2018

Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

For the purposes of this request, please refer to the Direct Testimony of David Prazak, Schedules 2, 4, and 5.

- a. Please provide all workpapers showing the calculations performed to arrive at the intraclass revenue distributions for each rate class shown in Schedule 4 from the marginal costs calculated in the Marginal Cost of Service Study shown in Schedule 2.
- b. Please provide all workpapers showing the calculations performed to arrive at the proposed base rate revenues for each rate class shown in Schedule 4 from the marginal costs calculated in the Marginal Cost of Service Study shown in Schedule 2.
- c. Please provide all workpapers showing the calculations performed to arrive at the proposed total revenues for each rate class shown in Schedule 4 from the marginal costs calculated in the Marginal Cost of Service Study shown in Schedule 2.
- d. Please provide all workpapers involved in the application of the Equal Percentage Marginal Cost (“EPMC”) methodology, or any variations thereof, to calculate each of the intraclass revenue distributions shown in Schedule 4.
- e. Please provide all workpapers showing the calculations done to arrive at the 2018 marginal customer-related costs for each rate class shown in Schedule 5 from the marginal costs calculated in the Marginal Cost of Service Study shown in Schedule 2.
- f. Please provide all workpapers and source documents in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Attachments: 9

Attachment 1 to DR ND-PSC-14.01_NOTPUBLIC.xlsx

Attachment 2 to DR ND-PSC-14.01_NOTPUBLIC.xlsx

Attachment 3 to DR ND-PSC-14.01_NOTPUBLIC.xlsx

Attachment 4 to DR ND-PSC-14.01_NOTPUBLIC.xlsx

Attachment 5 to DR ND-PSC-14.01_NOTPUBLIC.xlsx

Attachment 6 to DR ND-PSC-14.01_NOTPUBLIC.xlsx

Attachment 7 to DR ND-PSC-14.01_NOTPUBLIC.xlsx

Attachment 8 to DR ND-PSC-14.01.xlsx

Attachment 9 to DR ND-PSC-14.01.xlsx

Response:

This response references schedules, attachments, and/or exhibits that that Otter Tail deems to be trade secrets, valuable or sensitive commercial or financial information, or information that is otherwise confidential or proprietary and subject to restrictions against unauthorized use and disclosure under North Dakota law and the Parties' Confidentiality Agreement. Such materials are noted as NOT PUBLIC.

Attachments 1 through 8 to DR ND-PSC-14.01 will contain workpapers showing:

- a. the calculations performed to arrive at the intraclass revenue distributions for each rate class,
- b. the calculations performed to arrive at the proposed base rate revenues for each rate class
- c. the calculations performed to arrive at the proposed total revenues for each rate class shown in Schedule 4 from the marginal costs calculated in the Marginal Cost of Service Study shown in Schedule 2.
- d. The same attachments were involved in the application of the Equal Percentage Marginal Cost ("EPMC") methodology, or any variations thereof, to calculate each of the intraclass revenue distributions shown in Schedule 4.

Attachment 1 to DR ND-PSC-14.01_NOTPUBLIC – Residential and RDC class

Attachment 2 to DR ND-PSC-14.01_NOTPUBLIC – General Service Under and over 20 KW

Attachment 3 to DR ND-PSC-14.01_NOTPUBLIC – Large General Service and LGS TOD classes

Attachment 4 to DR ND-PSC-14.01_NOTPUBLIC – Area Lights

Attachment 5 to DR ND-PSC-14.01_NOTPUBLIC – Irrigation

Attachment 6 to DR ND-PSC-14.01_NOTPUBLIC – Large Dual Fuel and small Dual Fuel

Attachment 7 to DR ND-PSC-14.01_NOTPUBLIC – Deferred and Fixed Time of Service rates.

Attachment 8 to DR ND-PSC-14.01 – Updated Schedule 4.

In the response to DR ND-PCS-08.14 we addressed the change in the marginal cost value in the customer charge, by using the correct and lower marginal customer costs it impacted the marginal revenues which lead to an impact on EPMC. At the same time in the response to the DR ND-PSC-11.22 we addressed the changes in the Marginal Revenue Calculations in the

Interruptible rates, that had a material impact on the rate design. Both schedules are corrected and included for your information. Changes to the Large General Service EMPC calculations were addressed in the DR ND-MLEC-120. The impact of these changes and following rate design changes will be addressed in the compliance filing.

- e. The calculations performed to arrive at the 2018 marginal customer-related costs for each rate class shown in Schedule 5 from the marginal costs calculated in the Marginal Cost of Service Study shown in Schedule 2. For your convenience I am including Attachment 9 to DR ND-PSC-14.01 that contains the excerpt from the marginal cost study and includes the calculations requested.

PSC-14.01, ATTACHMENT 4
(NOT PUBLIC)

Downloaded from <http://ajph.org/> on November 10, 2014

The first two steps are the most important. The first step is to identify the problem. The second step is to define the problem. The third step is to identify the causes of the problem. The fourth step is to identify the effects of the problem. The fifth step is to identify the stakeholders involved in the problem. The sixth step is to identify the resources available to solve the problem. The seventh step is to identify the constraints on the problem. The eighth step is to identify the risks associated with the problem. The ninth step is to identify the opportunities associated with the problem. The tenth step is to identify the solutions to the problem.

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NOT PUBLIC DOCUMENT - NOT FOR PUBLIC DISCLOSURE

Case No. PU-17-398

Attachment 4 to DR ND-PSC-14.01

Page 4 of 8

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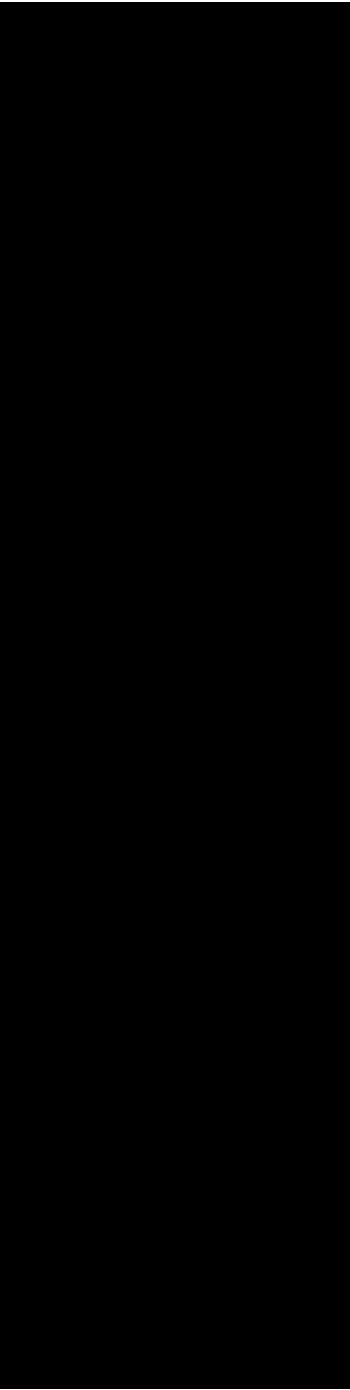
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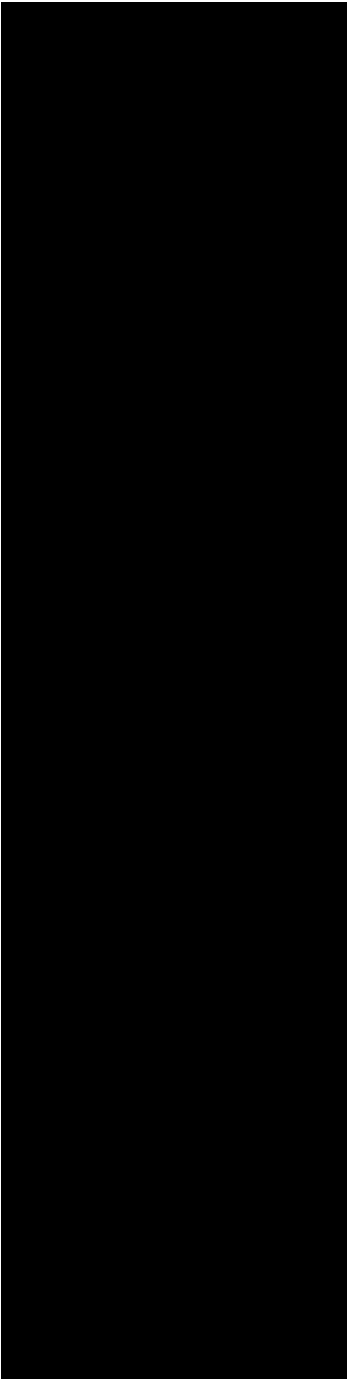
[REDACTED]

[REDACTED]

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The diagram consists of a grid of colored rectangles on the left and a series of vertical lines on the right. The grid is composed of several columns of rectangles, with colors including orange, yellow, green, and black. The vertical lines are black and white, with a small black arrow pointing to the right.





[illegible]

Case No. PU-17-398
Attachment 4 to DR ND-PSC-14.01
Page 1 of 1

[illegible]

[REDACTED] [REDACTED]

The diagram illustrates a network structure with nodes and connections. The nodes are represented by colored rectangles: yellow, black, white, and pink. The connections are represented by lines of various colors (yellow, black, grey) and styles (solid, dashed). The diagram is organized into several sections, with a central yellow area and a right side containing a 'DATA ENDS]' label.

DATA ENDS]

[PROTECTED DATA BEGINS...

NOT PUBLIC DOCUMENT - NOT FOR PUBLIC DISCLOSURE

Case No. PU-17-398

Attachment 4 to DR ND-PSC-14.01

Page 1 of 1

[REDACTED]

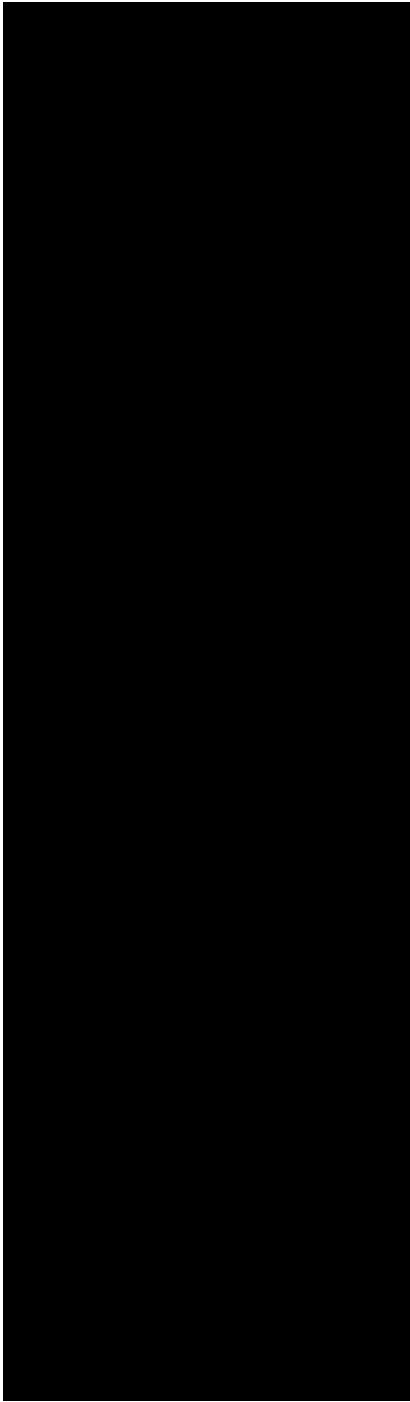
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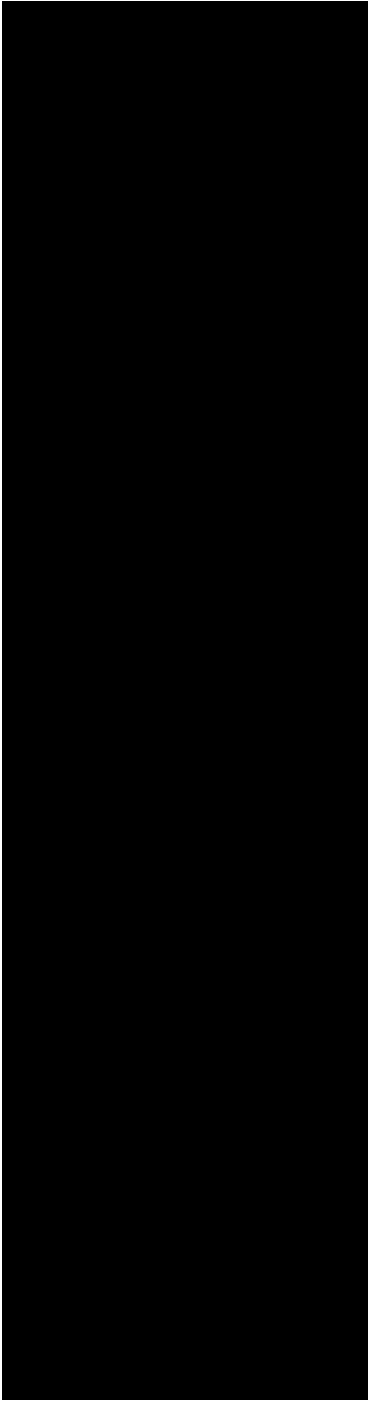
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PSC-17.25

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/25/2018

Date Due: 05/09/2018

Date of Response: 05/08/2018

Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Please refer to page 39 lines 21-24 of the Direct Testimony of David Prazak where he states “We are also proposing a slight modification to the classification of peak and off peak hours under this rate by extending the time of day concept to Sundays. And the proposed tariff sheets provide clarifications for the process of notifying customers of declared peak periods.”

- a. Please explain in detail how the Company determined the declared peak, intermediate, and off-peak hours?
- b. Please explain in detail why the Company is proposing to change the peak and off peak hours?
- c. Please explain how the Company will notify customer of the declared peak periods.
- d. Please explain why the Company is proposing to extend the peak and off-peak hours to Sundays.
- e. Please explain how costs were recovered from customers on Sundays prior to this proposed change change.
- f. Please provide all studies and analyses undertaken by or on the behalf of the Company that evaluate peak and off-peak periods for the irrigation rate class.
- g. Please provide the bill impacts for the irrigation rate class that will result from the Company’s proposed rate changes for this rate class.
- h. Please provide all workpapers and source documents in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Attachments: 0

Response:

- a. Please see the Company's response to question subparts (a.) and (b) stated in its response to DR ND-PSC-17.16.
- b. Please see Attachment 1 to the Company's response to DR ND-PSC-17.16.
- c. Please see the Company's response to question subpart (a.) stated in its response to DR ND-PSC-17.19.
- d. OTP is proposing to extend or introduce only "shoulder hours" to Sunday. These hours are defined in Table 7, Costing Periods – Option C at the recommendation of the report as shown in Attachment 1 to DR ND-PSC-17.16.
- e. Per Attachment 1 to DR ND-PSC-17.16, the report tested the suitability of the current costing periods (based on past marginal costs) to marginal costs in the period 2016-2018. Cost differentials on Sundays prior to the change may or may not have been fully recovered. Some recovery may have occurred the OTP's Energy Adjustment Rider.
- f. There are no studies or analyses responsive to this request.
- g. Customer usage is not driven by time of day schedule as much as crop condition and weather. Customers can choose time of day rate to facilitate economic energy usage balanced against crop yield economics. Nonetheless, Customers with the same billing determinants as the rate class results are expected to have bill impacts of 25.93% (See Schedule E1).
- h. There are no work papers.

PSC-18.22

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/25/2018

Date Due: 05/09/2018

Date of Response: 05/09/2018

Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Please refer to pages 55-58 of the Direct Testimony of David Prazak where he discusses the proposed Residential Time of Day Pilot.

- a. Please explain in detail how limiting the pilot program to only 50 customers will result in “cost effectiveness and statistically meaningful results”.
- b. Please provide all studies and analyses undertaken by or on the behalf of the Company that evaluated cost differentials during different time periods for the proposed Residential Time of Day Pilot.
- c. Please provide the load research data that the Company used to develop the Residential Time of Day Pilot tariff.
- d. Please provide a detailed explanation of all steps and processes the Company undertook in designing the rates for the proposed pilot to ensure that they were “revenue neutral”.
- e. Please explain in detail how the Company determined the amount of revenue that was necessary to be recovered from the proposed pilot in order for the residential rate classes level of revenues will be maintained.
- f. Please explain if the Company’s proposed Residential Time of Day pilot could potentially lead to the Company over-recovering or over-earning a return for the Residential Rate class?
- g. Please provide all workpapers used in the development of the “revenue neutral rates”.
- h. Please provide all workpapers and source documents in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Attachments: 3

Attachment 1 to DR ND-PSC-18.22.xlsx

Attachment 2 to DR ND-PSC-18.22.xlsx

Attachment 3 to DR ND PCS-18.22.xlsx

Response:

- a. As stated in Mr. Prazak's Direct Testimony, OTP has proposed a sample size of 50, for statistically meaningful results, attrition and cost effectiveness.
 - i. A sample size of 30 is widely accepted as sufficient for research purposes. While a larger sample should yield results closer to the population mean, the sampling methodology and central limit theorem support representativeness and the notion that the distribution of sample means will be normally distributed around the population mean.
 - ii. Because customers may elect to opt out of the pilot, OTP proposed a sample size greater than 30 to ensure a sufficient sample size for analysis.
 - iii. The current sample size of ND load research customers fitting the Pilot criteria is approximately 50. These individuals would be targeted to opt-in to the Pilot because 1. they were randomly selected from the population during the load research sampling process, 2. they have advanced meters installed and 3. they have historic data available, which will be useful in determining a baseline.
- b. There are no studies, except for the marginal costs study for on, shoulder and off-peak.
- c. Please refer to Attachment 1 to DR ND-PSC-18.22 – 2016 load research data for pilot eligible ND Residential customers and Attachment 2 to DR ND-PSC-18.22.
- d. Otter Tail Power determined the revenue requirements for the residential customer class by using an equal percent of marginal cost allocation method (EMPC). After determining that revenue requirement, a parallel computation for the time of day rate design was performed using the same billing determinants as the entire residential class. The only difference between the two is that the cumulative energy use that OTP had for all residential customers was allocated in time of day categories. Previously, it was not allocated into time of day categories. The new rates were designed to meet the same revenue requirement number, thereby making the new rate design revenue neutral to the original calculation.
- e. The Company determined the amount of revenue that was necessary to be recovered from the proposed pilot by designing this rate as revenue neutral, using the revenue requirement for the Residential rate (as explained above in response d.). In the response to DR ND-PCS-08.14 we addressed the change in the marginal cost value in the customer charge, by using the correct and lower marginal customer costs it impacted the marginal

revenues which lead to an impact on EPMC, this change is reflected in the attached work papers.

- f. Company's proposed Residential Time of Day pilot could can potentially lead to the Company under-recovering or under-earning a return for the Residential rate class if the customers take full advantage of the Off-Peak pricing and shift their usage to take the maximum advantage of the proposed rate and potential savings. The company is not aware of a potential over recovery scenario.
- g. and h. Please see Attachment 3 to DR ND-PSC-18.22 – Residential TOD rate design work papers.

PSC-18.24

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/25/2018

Date Due: 05/09/2018

Date of Response: 05/09/2018

Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Please refer to page 58 lines 28-29 of the Direct Testimony of David Prazak where he states “If approved, OTP plans for the Pilot to remain open for two years, effective January 1, 2019.”

- a. Please explain if the Company is proposing any review and evaluation process of the results of Pilot program at the end of the two year period.
- b. If the response to (a) is affirmative, please explain how the Company will go about initiating this review and evaluation process and whether or not this review process will be open to Commission Staff and other stakeholders.
- c. If the response to (a) is negative, please explain why the Company will not be undertaking a review and evaluation process of the results of the pilot program.

Attachments: 0

Response:

- (a) The Company will review participation levels (customer interest), and bill impacts to participants compared to if the customer would have taken service under the standard Residential rate. The Company will also evaluate if the customers have shifted load to lesser price periods or simply not responded to price signals and continued to purchase energy during on-peak periods. If it is determined customers are indeed moving load to lesser price periods, the program will likely be determined a success. If load is not being moved, Otter Tail will re-evaluate the program and determine to either terminate or modify.

- (b) If customer response is positive, the Company will likely plan to transition the pilot to a long-term program and make a formal filing with the Commission describing the participation levels, customer experiences, and reasons for making the program permanent long-term.
- (c) See the response to (a).

PSC-18.25

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/25/2018

Date Due: 05/09/2018

Date of Response: 05/09/2018

Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Please refer to page 59 lines 9-12 of the Direct Testimony of David Prazak where it states “If a customer chooses to return to other available rate schedules after the trial period, the customer will pay a charge of \$20.00 for removal of time of day metering equipment.” Please provide the basis and calculation for the proposed \$20.00 removal charge. Please provide all workpapers and source documents in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Attachments: 0

Response:

	From Accounting Circular 5			
Title	Minimum billing rate/hr	hours		Comments
Service Rep	\$67	0.75	\$50.25	Time to set up truck, Test rubber gloves, energize/de-energize, paperwork

A loaded rate for a lineman with truck is \$67/hr. We conservatively assume 45 minutes for transportation and replacement of the meter. The \$20 removal charge does not cover all of the costs of the removal. We believe these revenues to be very minimal but help to contribute to the costs of removal and reduce cross-subsidies.

PSC-18.28

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/25/2018

Date Due: 05/09/2018

Date of Response: 05/09/2018

Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Please refer to page 68 lines 11-14 of the Direct Testimony of David Prazak where he states “OTP is proposing to close the Outdoor Lighting (Section 11.04) to new customers and replacements. Current customers will be served on the closed rate until their existing light fails. The new proposed LED Lighting Service (Section 11.07) will provide services to new customers and replacements.”

- a. Please explain in detail why the company is proposing to close the outdoor lighting tariff?
- b. Please explain why the Company is not proposing for the LED Lighting Service to be optional for customers?
- c. Please explain has the Company evaluated the rate impacts of the Outdoor lighting class when these customers are moved entirely to the LED Lighting Service Tariff? Please provide all workpapers and source documents in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.
- d. Please explain if a customer is required to replace their existing light when it fails with an LED fixture, would the Company agree that this would result in the customer being served under multiple lighting tariffs at one time since not all existing fixtures are likely to fail at the same time.
- e. If the response to (d) is affirmative please explain how the Company will bill this customer for usage for the individual fixtures on each lighting tariff?

- f. If the response to (d) is negative please explain how this outcome will not occur and how the Company will bill the customer?
- g. Does the Company individually meter each outdoor light and street light in its service territory?

If the response to (g) is negative, please explain how the Company determines the usage of its outdoor lighting and street lighting customers.

Attachments: 1

Attachment 1 to DR ND-PSC-18.28.xlsx

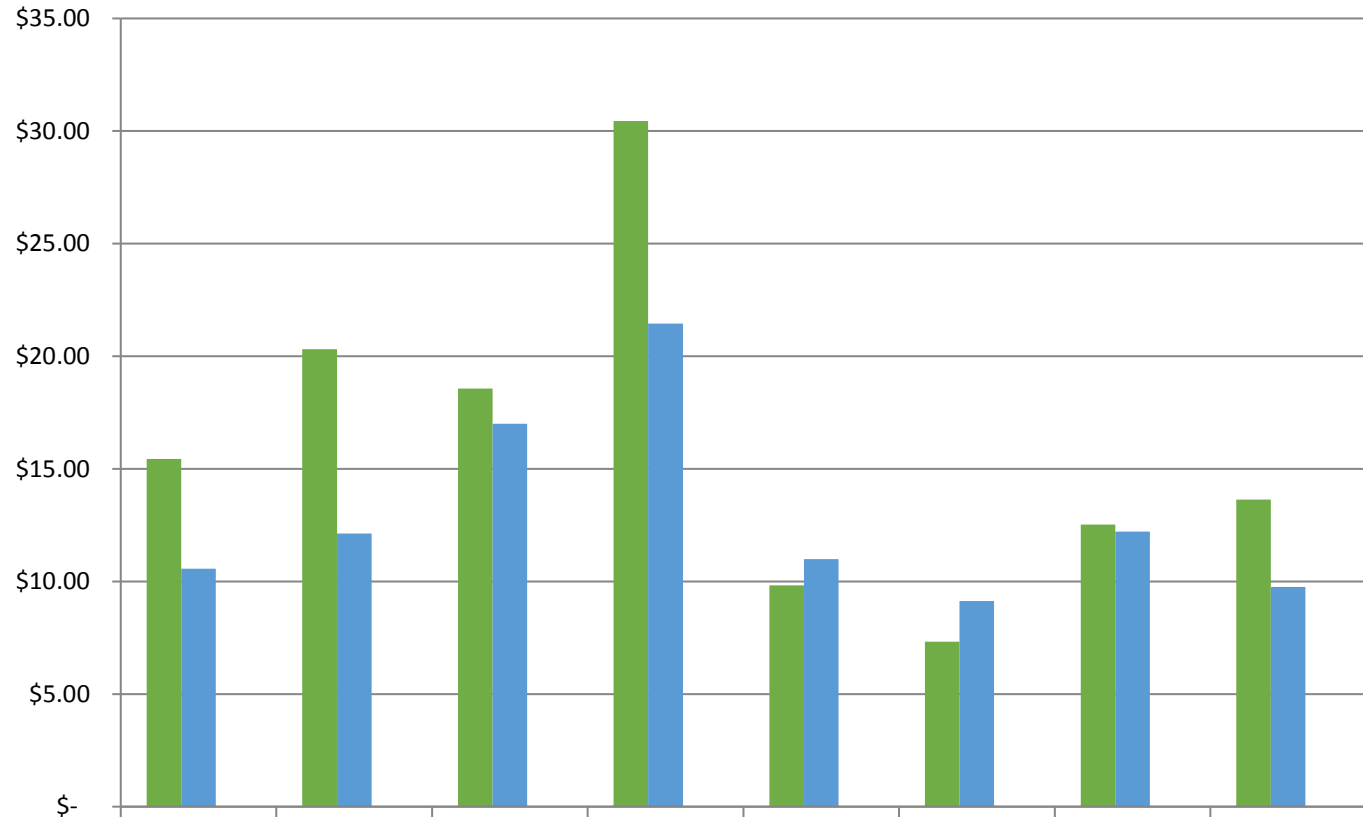
Response:

- a. For detail explanation of how the company used the marginal cost of service in evaluating LED fixtures and pole offerings, please refer to page 67 lines 3-14 of the Direct Testimony of David Prazak.
- b., c., d., & e.
Please see Attachment 1 to DR ND-PSC-18.28 LED Outdoor Lighting Data with LED 2017 MC.

PSC-18.28, ATTACHMENT 1

New & Existing Light Type	Annual Bill Quantity	Current Monthly Rate	LED Weighted Monthly Rate Current	LED Weighted Monthly Rate (Rate Case) Proposed	LED MARGINAL RATE
LED10	604.15		\$ 15.44	\$ 15.71	\$10.56
HPS23	557.78	\$ 15.40			
MA20	-	\$ 18.38			
MV11	8.03	\$ 12.70			
MV21	38.34	\$ 16.72			
LED13	429.15		\$ 20.32	\$ 20.66	\$12.13
HPS44	381.86	\$ 19.01			
MA110	29.90	\$ 38.41			
MA36	17.39	\$ 18.00			
MV35	-	\$ 24.53			
MV55	-	\$ 31.36			
LED20FLOOD	1,730.04		\$ 18.56	\$ 18.98	\$17.01
400 MV	165.78	\$ 17.35			
4CHPS	16.84	\$ 12.94			
400 HPS	968.90	\$ 18.90			
400 MA	578.52	\$ 18.49			
LED30FLOOD	378.55		\$ 30.45	\$ 30.96	\$21.45
1M-HPSF	1.08	\$ 30.44			
1000-MV	376.23	\$ 30.44			
1000-MA	1.25	\$ 32.11			
LED3PT	454.39		\$ 9.83	\$ 10.01	\$11.00
HPS9PT	273.60	\$ 9.72			
MV6PT	180.78	\$ 10.00			
LED5	16,359.73		\$ 7.32	\$ 7.44	\$9.14
HPS14	195.86	\$ 11.71			
HPS9	7,095.74	\$ 7.52			
MA8	391.31	\$ 8.46			
MV6	8,676.82	\$ 7.01			
LED5PT	47.51		\$ 12.53	\$ 12.75	\$12.21
HPS14PT	47.51	\$ 12.53			
MA8PT	-	\$ -			
LED8	89.10		\$ 13.64	\$ 13.88	\$9.75
HPS19	88.10	\$ 13.61			
MA14	1.00	\$ 16.10			

Chart 1
Comparison of the proposed LED Rate options
and Class Revenue Impact



LED Weighted Monthly Rate Current	\$15.44	\$20.32	\$18.56	\$30.45	\$9.83	\$7.32	\$12.53	\$13.64
LED Marginal Cost based Rate	\$10.56	\$12.13	\$17.01	\$21.45	\$11.00	\$9.14	\$12.21	\$9.75
Class Revenue impact, %	5.0%	4.6%	17.1%	6.1%	2.4%	63.8%	0.3%	0.6%

[illegible]

Line No. 1	Fixture Type	FIBERG LASS STANDA RDS FS18	FIBERG LASS STANDA RDS FS23	ALUMINUM ALLOY STANDARDS 30'	ALUMINUM ALLOY STANDARDS 40'	STANDARD POLE (LED5, LED8 & LED10)	STANDARD POLE (LED13 & LED20 FLOOD)	STANDAR D POLE (LED30 FLOOD)
2	Calculated Fixture Life (yrs.)	50.00	50.00	50.00	50.00	50.00	50.00	50.00
3	Pole Cost	\$330.06	\$464.32	\$1,519.90	\$1,772.71	\$224.00	\$320.15	\$670.30
4	Pole Labor	\$105.21	\$105.21	\$351.42	\$351.42	\$351.42	\$395.10	\$439.28
5	Bracket Cost					\$54.22	\$70.52	\$70.52
6	Hardware Cost			\$590.62	\$590.62	\$21.44	\$29.35	\$29.35
7	Hardware Labor			\$71.45	\$71.45	\$0.00	\$0.00	\$0.00
8	(Other) Conductor Cost	\$69.12	\$69.12	\$131.33	\$131.33	\$55.14	\$55.14	\$55.14
9	Vibratory Plowing \$1.75/ft. (Other) Conductor Labor	\$262.50	\$262.50	\$314.41	\$319.47	\$115.50	\$115.50	\$115.50

Line No. 1	Fixture Type	LED5	LED5 - Retrofit	LED10	LED10 - Retrofit	LED3PT	LED3PT - Retrofit	LED5PT	LED5PT - Retrofit	LED8	LED8 - Retrofit	LED13	LED13 - Retrofit	LED20 FLOOD	LED20 FLOOD - Retrofit	LED30 FLOOD	LED30 FLOOD - Retrofit	FIBERG LASS STANDARDS RDS FS18	FIBERG LASS STANDARDS RDS FS23	ALUMINUM ALLOY STANDARDS 30'	ALUMINUM ALLOY STANDARDS 40'	STANDA RD POLE (LED5, LED8 & LED10)	STANDA RD POLE (LED13 & LED20 FLOOD)	STANDA RD POLE (LED30 FLOOD)
2	Calculated Fixture Life (yrs.)	24.39	24.39	24.39	24.39	24.39	24.39	24.39	24.39	24.39	24.39	24.39	24.39	24.39	24.39	24.39	24.39	50.00	50.00	50.00	50.00	50.00	50.00	50.00
3	Lamp Watts	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	199	199	261	261							
4	Current Supplier Total Watts	47	32	95	95	26	26	47	47	76	76	133	133	67.99	67.99	89.18	89.18							
5	kWh per Month	16.06	10.93	32.46	32.46	8.88	8.88	16.06	16.06	25.97	25.97	43.33	43.33	67.99	67.99	89.18	89.18							
6	Lumens	5175	4100	12388	12388	2759	2759	5404	5404	9003	9003	16691	16691	23067	23067	32003	32003							
7	Light Distribution	E1		E1						E1		E1												
8	4100 hrs./yr. Lamp Life (HRS.)	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000	100000							
9	Years PE Life	11	11	11	11	11	11	20	20	11	11	11	11	11	11	11	11							
10	Lamp Cost	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00	\$ 40.00											
11	OTP Stock Number	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A											
12	Photo Eye	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37							
13	DTL ALT Photo Eye	18.42																						
14	Years Driver Life	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12							
15	Energy Billing, \$/kWh	\$ 0.02124	\$ 0.34108	\$ 0.23222	\$ 0.68942	\$ 0.68942	\$ 0.18868	\$ 0.18868	\$ 0.34108	\$ 0.55153	\$ 0.55153			\$ 1.44414	\$ 1.44414	\$ 1.89408	\$ 1.89408							
16	Fixture OTS#	183440000	183440000	183445000	183445000	183455000	183458000	183458000	183444500	183444500	183444500	183447000	183447000	183450000	183450000	183451000	183451000							
17	Current GE Cat #	ERS1004HE140AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY	ERS1010E240AGRAY							
18	GE Price BSE	\$500.00	\$500.00	\$430.51	\$430.51	\$840.54	\$840.54	\$908.87	\$908.87	\$280.17	\$280.14	\$505.69	\$505.69	\$820.04	\$820.04	\$1,025.05	\$1,025.05							
19	AEL Cat#	AT18MFMVOLT8		AT18MFMVOLT8		AR18MFMVOLT8		AR18MFMVOLT8		AT18MFMVOLT8		AT18MFMVOLT8		AR18MFMVOLT8		AR18MFMVOLT8								
20	AEL Price BSE	\$176.31	\$176.31	\$307.52	\$307.52	\$478.35	\$478.35	\$512.52	\$512.52	\$225.51	\$225.51	\$348.52	\$348.52	\$888.37	\$888.37	\$1,081.76	\$1,081.76							
21	Fixture Price BSE	\$176.31	\$176.31	\$307.52	\$307.52	\$478.35	\$478.35	\$512.52	\$512.52	\$225.51	\$225.51	\$348.52	\$348.52	\$888.37	\$888.37	\$1,081.76	\$1,081.76							
22	TOTAL Fixture LABOR WOE	\$91.08	\$146.08	\$91.08	\$146.08	\$73.08	\$147.48	\$73.08	\$147.48	\$91.08	\$91.08	\$91.08	\$146.08	\$154.81	\$232.21	\$154.81	\$232.21	\$330.06	\$464.32	\$1,519.90	\$1,772.71	\$224.00	\$320.15	\$670.30
23	Pole Cost																	\$105.21	\$105.21	\$351.42	\$351.42	\$351.42	\$395.10	\$439.28
24	Pole Labor																					\$54.22	\$70.52	\$70.52
25	Bracket Cost																					\$0.00	\$0.00	\$0.00
26	Bracket Labor																					\$590.62	\$29.35	\$29.35
27	Hardware Cost																					\$21.44	\$0.00	\$0.00
28	Hardware Labor																					\$71.45	\$0.00	\$0.00
29	(Other) Conductor Cost																					\$131.33	\$55.14	\$55.14
30	Vibratory Plowing \$1.75/ft. (Other) Conductor Labor		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00	\$69.12	\$69.12	\$131.33	\$131.33	\$115.50	\$115.50	\$115.50
31	Warehousing Other Costs	27%	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
32	Bulb & PE Maintenance Costs		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
33	Monthly O+M Costs		\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.98	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00

Facilities and O&M Related Costs			LED5	LED5 - Retrofit	LED10	LED10 - Retrofit	LED3PT	LED3PT - Retrofit	LED6PT	LED6PT - Retrofit	LED8	LED8 - Retrofit	LED13	LED13 - Retrofit	LED20 FLOOD	LED20 FLOOD - Retrofit	LED30 FLOOD	LED30 FLOOD - Retrofit	SECURITY LIGHT (OPEN BOTTOM) LED5	SECURITY LIGHT (OPEN BOTTOM) LED8	FIBERGLAS STANDARD 8 FTx3	FIBERGLAS STANDARD 8 FTx3.5	ALUMINUM ALLOY STANDARDS	ALUMINUM ALLOY STANDARDS4	STANDARD POLE (LED5, LED8 & LED10)	STANDARD POLE (LED13 & LED20 FLOOD)	STANDARD POLE (LED30 FLOOD)
(1)	Marginal Investment per fixture (all costs and labor)	Input - Lighting Cost worksheets	\$267.39	\$322.39	\$398.60	\$453.60	\$551.43	\$625.83	\$585.60	\$660.00	\$316.59	\$316.59	\$439.60	\$494.60	\$874.85	\$1,052.25	\$1,179.86	\$1,257.26	\$1,100.73	\$334.01	\$766.89	\$901.15	\$2,979.13	\$3,237.08	\$821.72	\$985.76	\$1,380.09
(2)	With General Plant Loading	(1) x 1.030	\$270.87	\$326.58	\$463.76	\$459.50	\$558.60	\$633.97	\$593.21	\$668.58	\$320.71	\$320.71	\$445.31	\$501.03	\$887.52	\$1,065.93	\$1,195.20	\$1,273.60	\$1,115.04	\$338.35	\$776.86	\$912.86	\$3,017.86	\$3,279.08	\$832.40	\$998.57	\$1,398.03
(3)	Annual Economic Carrying Charge Related to Capital Investment	(7) Input - Marginal Cost Study T29 P5	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
(4)	A&G Loading (plant-related)	(10) Input - Marginal Cost Study T29 P5	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(5)	Total Annual Carrying Charge	(3) + (4)	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%
(6)	Annualized Costs	(2) x (5)	\$25.97	\$31.31	\$38.71	\$44.05	\$53.56	\$60.78	\$56.87	\$64.10	\$30.75	\$30.75	\$42.69	\$48.04	\$94.68	\$102.19	\$114.59	\$122.11	\$106.90	\$32.44	\$52.81	\$62.05	\$205.14	\$222.90	\$56.58	\$67.88	\$95.03
(7)	Annual Lighting O&M Expenses	Input - Lighting Cost worksheets	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$13.76	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
(8)	With A&G Loading (non-plant related)	(7) x 1.1323 Input-Marginal Cost Study	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$13.32	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
(9)	Distribution Facilities Related Costs	(6) + (8)	\$39.28	\$44.63	\$52.03	\$57.37	\$66.87	\$74.10	\$70.19	\$77.42	\$44.06	\$44.06	\$56.01	\$61.35	\$107.99	\$115.51	\$127.90	\$135.42	\$106.90	\$32.44	\$52.81	\$62.05	\$205.14	\$222.90	\$56.58	\$67.88	\$95.03
(10)	Working Capital	(2) x 1.20%	\$3.25	\$3.92	\$4.85	\$5.51	\$6.70	\$7.61	\$7.12	\$8.02	\$3.85	\$3.85	\$5.34	\$6.01	\$11.85	\$12.79	\$14.34	\$15.28	\$13.38	\$4.06	\$9.32	\$10.95	\$36.21	\$39.35	\$9.99	\$11.98	\$16.78
(11)	Prepayments	(2) x 0.03%	\$0.08	\$0.10	\$0.12	\$0.14	\$0.17	\$0.19	\$0.18	\$0.20	\$0.10	\$0.10	\$0.13	\$0.15	\$0.30	\$0.32	\$0.36	\$0.38	\$0.33	\$0.10	\$0.23	\$0.27	\$0.91	\$0.98	\$0.25	\$0.30	\$0.42
(12)	Cash Working Capital Allowance	(8) x 6.67%	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.89	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
(13)	Total Working Capital	(10) + (11) + (12)	\$4.22	\$4.91	\$5.85	\$6.54	\$7.76	\$8.69	\$8.18	\$9.11	\$4.83	\$4.83	\$6.37	\$7.05	\$13.03	\$14.00	\$15.59	\$16.55	\$13.71	\$4.16	\$9.56	\$11.23	\$37.12	\$40.33	\$10.24	\$12.28	\$17.20
(14)	Revenue Requirement for Working Capital	(13) x 11.20%	\$0.47	\$0.55	\$0.66	\$0.73	\$0.87	\$0.97	\$0.92	\$1.02	\$0.54	\$0.54	\$0.71	\$0.79	\$1.46	\$1.57	\$1.75	\$1.85	\$1.54	\$0.47	\$1.07	\$1.26	\$4.16	\$4.52	\$1.15	\$1.38	\$1.93
(15)	Total Annual Marginal Distribution Facilities Related Costs	(9) + (14)	\$39.76	\$45.18	\$52.68	\$58.10	\$67.74	\$75.07	\$71.11	\$78.44	\$44.60	\$44.60	\$56.72	\$62.14	\$109.45	\$117.08	\$129.65	\$137.28	\$108.44	\$32.91	\$53.88	\$63.31	\$209.30	\$227.42	\$57.73	\$69.25	\$96.96
O&M - Meter, Customer Accounts Expenses, Customer Service																											
(16)	Meter and CT O&M Expenses	(13) Input - Marginal Cost Study T29 P5	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
(17)	Customer Accounts Expenses	(14) Input - Marginal Cost Study T29 P5	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39	\$2.39
(18)	Customer Service and Informational Expenses	(15) Input - Marginal Cost Study T29 P5	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10	\$1.10
(19)	With A&G Loading (Non-plant Related)	(16)+(17)+(18) x 1.1323	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95
(20)	Customer-Related Costs	(19)	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95	\$3.95
(21)	Working Capital																										
(22)	Materials and Supplies		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
(23)	Prepayments		\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
(24)	Cash Working Capital	(19) x 6.67%	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26	\$0.26
(25)	Revenue Requirement for Working Capital	[(21)+(22)+(23)]x1.20%	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03
(26)	Total Annual Marginal Customer-Related Costs	(20) + (24)	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98	\$3.98
(27)	Total Annual Marginal Facilities & Customer-Related Costs per fixture	(15) + (25)	\$43.74	\$49.16	\$56.67	\$62.08	\$71.72	\$79.05	\$75.09	\$82.42	\$48.59	\$48.59	\$60.70	\$66.12	\$113.43	\$121.06	\$133.63	\$141.26	\$112.42	\$36.89	\$57.86	\$67.29	\$213.28	\$231.40	\$61.71	\$73.24	\$100.94
(28)	Monthly Marginal Facilities & Customer-Related Costs per lighting fixture	(26) / 12	\$3.64	\$4.10	\$4.72	\$5.17	\$5.98	\$6.59	\$6.26	\$6.87	\$4.05	\$4.05	\$5.06	\$5.51	\$9.45	\$10.09	\$11.14	\$11.77	\$9.37	\$3.07	\$4.82	\$5.61	\$17.77	\$19.28	\$5.14	\$6.10	\$8.41
Energy Costs Calculation per Fixture																											
(29)	Lighting fixture input (connected kW)	Input - Mfg data	0.047	0.032	0.095	0.095	0.026	0.026	0.047	0.047	0.076	0.076	0.133	0.133	0.199	0.199	0.261	0.261	0.047	0.047	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(30)	Monthly change per connected (Marginal kWh rate/12months)	\$7.26 Input Section 11.03, Rate Code 31-749	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26	\$7.26
(31)	Monthly kWh charge	(29) x 27	\$0.34	\$0.23	\$0.69	\$0.69	\$0.19	\$0.19	\$0.34	\$0.34	\$0.55	\$0.55	\$0.97	\$0.97	\$1.44	\$1.44	\$1.89	\$1.89	\$0.34	\$0.34	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total Monthly Fixture Cost																											
(29)	Monthly Marginal Cost per fixture (excluding monthly energy)	(27)	\$3.64	\$4.10	\$4.72	\$5.17	\$5.98	\$6.59	\$6.26	\$6.87	\$4.05	\$4.05	\$5.06	\$5.51	\$9.45	\$10.09	\$11.14	\$11.77	\$9.37	\$3.07	\$4.82	\$5.61	\$17.77	\$19.28	\$5.14	\$6.10	\$8.41
(30)	Monthly kWh charge	(28)	\$0.34	\$0.23	\$0.69	\$0.69	\$0.19	\$0.19	\$0.34	\$0.34	\$0.55	\$0.55	\$0.97	\$0.97	\$1.44	\$1.44	\$1.89	\$1.89	\$0.34	\$0.34	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
(31)	Total Monthly Pole Cost	(29)	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14	\$5.14
(32)	Total Monthly Fixture Cost	(27) + (29)+(30)	\$9.13	\$4.33	\$10.55	\$5.86	\$10.99	\$6.78	\$12.21	\$7.21	\$9.74	\$4.60	\$12.13	\$6.48	\$17.00	\$11.53	\$21.44	\$13.67	\$14.85	\$3.41	\$4.82	\$5.61	\$17.77	\$19.28	\$5.14	\$6.10	\$8.41

----- (2016 Dollars per fixture) -----

LED5	LED5 - Retrofit	LED10	LED10 - Retrofit	LED3PT	LED3PT - Retrofit	LED8PT	LED8PT - Retrofit	LED8	LED8 - Retrofit	LED13	LED13 - Retrofit	LED20 FLOOD	LED20 FLOOD - Retrofit	LED30 FLOOD	LED30 FLOOD - Retrofit	SECURITY LIGHT (OPEN BOTTOM) LED5	SECURITY LIGHT (OPEN BOTTOM) LED8	FIBERGLAS STANDARD 8 FTx3	FIBERGLAS STANDARD 8 FTx3.5	ALUMINUM ALLOY STANDARDS 3W	ALUMINUM STANDARDS4	STANDARD POLE (LED5, LED8 & LED10)	STANDARD POLE (LED13 & LED20 FLOOD)	STANDARD POLE (LED30 FLOOD)

Light Type	LED Light Type
HPS23	LED10
MH20	LED10
MV11	LED10
MV21	LED10
HPS44	LED13
MH110	LED13
MH36	LED13
MV35	LED13
400 HPS	LED20FLOOD
400 MA	LED20FLOOD
400 MV	LED20FLOOD
SIGN	LED20FLOOD
1000-MA	LED30FLOOD
1000-MV	LED30FLOOD
1M-HPSF	LED30FLOOD
HPS9PT	LED3PT
MV6PT	LED3PT
HPS14	LED5
HPS9	LED5
MH8	LED5
MV6	LED5
HPS14PT	LED5PT
MH8PT	LED5PT
HPS19	LED8
MH14	LED8

Street and Area Lighting	
HID (OLD) Light Type	LED Equivalent Light Type
HPS9PT	LED3PT
MV6PT	LED3PT
HPS14	LED5
HPS9	LED5
MH8	LED5
MV6	LED5
HPS14PT	LED5PT
MH8PT	LED5PT
HPS19	LED8
MH14	LED8
HPS23	LED10
MH20	LED10
MV11	LED10
MV21	LED10
HPS44	LED13
MH110	LED13
MH36	LED13
MV35	LED13

Area Flood Lighting	
HID (OLD) Light Type	LED Equivalent Light Type
400 HPS	LED20FLOOD
400 MA	LED20FLOOD
400 MV	LED20FLOOD
SIGN	LED20FLOOD
1000-MA	LED30FLOOD
1000-MV	LED30FLOOD
1M-HPSF	LED30FLOOD

PSC-18.30

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/25/2018

Date Due: 05/09/2018

Date of Response: 05/09/2018

Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Please refer to page 68 lines 11-14 of the Direct Testimony of David Prazak where he states “OTP is proposing to close the Outdoor Lighting (Section 11.04) to new customers and replacements. Current customers will be served on the closed rate until their existing light fails. The new proposed LED Lighting Service (Section 11.07) will provide services to new customers and replacements.”

- a. Please explain in detail why the company is proposing to close the outdoor lighting tariff?
- b. Please explain why the Company is not proposing for the LED Lighting Service to be optional for customers?
- c. Please explain has the Company evaluated the rate impacts of the Outdoor lighting class when these customers are moved entirely to the LED Lighting Service Tariff? Please provide all workpapers and source documents in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.
- d. Please explain if a customer is required to replace their existing light when it fails with an LED fixture, would the Company agree that this would result in the customer being served under multiple lighting tariffs at one time since not all existing fixtures are likely to fail at the same time.
- e. If the response to (d) is affirmative please explain how the Company will bill this customer for usage for the individual fixtures on each lighting tariff?
- f. If the response to (d) is negative please explain how this outcome will not occur and how the Company will bill the customer?

- g. Does the Company individually meter each outdoor light and street light in its service territory?
- h. If the response to (g) is negative, please explain how the Company determines the usage of its outdoor lighting and street lighting customers.

Attachments: 0

Response:

- a. Otter Tail is proposing to close the current outdoor lighting tariff for two main reasons. First, having two different lighting technologies, in the long term, is unsustainable from a cost and supply perspective. Second, the new LED options are many times more efficient than the current high-intensity discharge (HID) technologies, and LED's have much longer lifetimes for reduced O&M.
- b. Otter Tail's flexible approach allows the current HID lights to continue to operate until time of failure. At time of failure the Company will replace them with LEDs extending the lifetime of equipment, lowering energy consumption and reducing operation and maintenance costs moving forward. LED prices have dropped substantially over the last several years, while lighting industry experts state the HIDs are being manufactured less and less.

The cost premium for the LED5 over the HPS9 (the most common HID on Otter Tail's system) is currently only \$15.00. The annual kWh savings associated with the LED5 is 407 kWh compared to the HPS9. Adding in substantially less maintenance costs further drives cost savings for customers.

Customer interest in LEDs is growing all the time. Otter Tail has a list of North Dakota towns requesting LEDs in their communities. If the proposed changes to rate schedule Sections 11.04 and 11.07 are approved Otter Tail plans to respond to these customer community requests and changeout their lighting systems to LEDs.

Some key features of LEDs:

- LED is a directional light source with no need for reflectors or lenses to direct light onto the surface being illuminated.
- LED fixtures are better at distributing light over a greater distance from the fixture, leaving less of a hot spot directly beneath the fixture.
- LED fixtures require fewer lumens to produce equivalent levels of illumination on roadways, streets, or parking lots.
- LED lumen depreciation is 30 percent over its 100,000-hour rated life, whereas High Pressure Sodium lumen depreciation is 20 percent over its relatively short 24,000 hour rated life. Mercury Vapor and metal halide fixtures have even poorer performance.

- LED fixtures offer a more gradual reduction in lumens over a much longer period of time.
- c. The Company studied the Marginal Costs of the LED fixtures, comparing Marginal LED Rates to the Proposed LED rates, created by using the Weighted Average Method. Please refer to page 68 Figure 17 of the Direct Testimony of David Prazak or tab “Chart1” in the Attachment 1 to DR ND-PSC-18.28 LED Outdoor Lighting Data with LED 2017 MC.

Due to the LED’s lower energy consumption, significantly lower maintenance, longer lamp life, and material costs for the LED trending downward, Otter Tail believes lighting rates for LEDs will be cheaper than HID in the long run. Considering the lower maintenance cost of LEDs and longer lamp life, the \$15 of additional upfront cost of an LED fixture over an HID fixture is more than offset by avoiding even a single maintenance visit by Otter Tail, much less the number of avoided visits over the life of the fixture.

- d. The presented scenario is possible. This scenario is not uncommon under current conditions. A community may have lights they own and are metered on a certain tariff, while they typically also have lights that Otter Tail owns, which are charged a flat charge each month. This is common and simple to administer.
- e. It is important to note the lights being discussed in this proposal are Company-owned lights installed at the customers’ request for the customer’s use. Area lights are billed on a monthly tariff, calculated, based on the size of the fixture operating for 4,100 hours of service annually. These operating hours are supported by load research data. If the fixture is replaced in between billing cycles the tariffs will be prorated.
- f. N/A
- g. The Company does not individually meter each outdoor light and street light in its service territory.
- h. The Company determines the usage of its outdoor lighting and street lighting customers based on the demand or load of the fixture over the 4,100 annual hours of operation. For example, $1 \text{ kW/fixture} * 4,100 \text{ hrs/yr} = 4,100 \text{ kWh's/year}$.

PSC-18.31

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/25/2018

Date Due: 05/09/2018

Date of Response: 05/09/2018

Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Please refer to page 69 lines 22-23 of the Direct Testimony of David Prazak where he states “OTP proposes a credit of \$6.00 per ton of cooling capacity, per month, during the program billing months of June through September.”

- a. Please explain in detail how the Company determined the rate credit of \$6.00 per ton of cooling capacity, per month.
- b. Please explain how providing a rate credit for cooling capacity is consistent with the Company’s proposal to set rates at marginal cost?
- c. Please provide all workpapers and source documents in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Attachments: 1

Attachment 1 to DR ND-PSC-18.31.xlsx

Response:

- a. The bill credit is calculated per the work paper that is provided as Attachment 1 to DR ND-PSC-18.31, please refer to the tab labeled “Credit Calculation”. By taking into account the control hours, load reduction and marginal cost of these hours, one can determine cost of avoided service for the control periods. In this calculation, that was \$6.94/mo. After subtracting equipment costs used to implement load control, Otter Tail rounded up to \$6/mo. for ease of administration and benefit to the customer.

- b. Keeping the bill credit in place allows the company access to controllable load and by assigning a value to that controllable load, the customer is able to share in the benefit of providing that resource to the company.

It is also important to recognize the financial benefit interruptible loads deliver to all customers classes. Otter Tail continually monitors market energy prices and controls loads like Commercial Cool Savings when prices are high in the energy market. Otter Tail defines this strategy as economic control. By performing economic control, all classes of Otter Tail's customers benefit by paying less monthly fuel costs.

- c. Attachment 1 to DR ND-PSC-18.31 - AC Credit ND 2018.

MLEC-209

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Referring to OTP's proposal for a Generation Cost Recovery Rider (GCRR):

- a. Please explain how OTP's management of costs of the Astoria generating station proposed for being placed in service after the test year will be controlled and subject to scrutiny if OTP's request for a generation cost recovery rider is approved. Is OTP suggesting any cost control measures? If so, please explain.
- b. Is OTP expecting to recover in its proposed GCRR any costs of projects other than the 250 MW CT generation project such as wind projects or transmission outlet? Please explain.

Attachments: 0

Response:

- a. OTP will retain the engineering, project management, and construction management services of an experienced engineer on this project. Through competitive bidding and normal project controls related to cost, quality and schedule, OTP will work towards bringing the project to commercial operation at or under budget. Routine project updates and monthly meetings with upper management will be held to inform them as to the budget and schedule status throughout the course of the project. Additionally, OTP will apply to update the rate each year and supply updated cost information for review with each update application. Each update application will be subject to the Commission's approval. In this rate case, OTP is requesting that the mechanism be approved for future use.

- b. The 250 MW CT project (Astoria Station) is the only currently planned project OTP would seek recovery of through the GCRR during its construction. The costs currently contemplated for recovery in the GCRR are the costs of Astoria Station that were addressed in the ADP docket (PU-17-140), which include the necessary transmission upgrades. OTP will seek recovery of any future wind or other renewable projects through the renewable rider and transmission projects through the transmission rider. Whether a rider is used will depend on the timing of OTP's next general rate case in North Dakota.

Company	Number of Customers	Substation Capacity (Mva)	Number of Transformers	Substation Capacity (Mva/ 1,000 Customers)	Number of Transformers (Transformers/ 1,000 Customers)	Capacity Rank	Transformer Rank	Residential Customer Charge	Small Commercial Customer Charge
OtterTail Power Company	131,852	5,075	105	38.49	0.80	3	8	\$ 15.23	\$ 24.90
ALLETE, Inc. ³	146,370	8,157	221	55.73	1.51	1	4		
MN								8.00	10.50
Black Hills Energy ^{1,3}	72,026	2,607	95	36.20	1.32	4	5		
SD								9.25	12.00
WY								15.50	28.00
Cheyenne Light Fuel & Power d/b/a Black Hills Energy ³	42,013	1,633	24	38.87	0.57	2	12		
WY								13.00	16.00
Interstate Power and Light Co ³	489,611	6,364	549	13.00	1.12	13	6		
IA								13.50	24.00
Madison Gas & Electric Co	152,603	1,203	99	7.88	0.65	16	10		
WI								19.00	23.93
MDU Resources	142,901	5,002	528	35.00	3.69	6	1		
MT								5.17	15.21
ND								13.99	25.55
SD								7.51	15.51
WY								25.00	29.99
MidAmerican Energy Co ³	770,335	21,774	517	28.27	0.67	9	9		
IA								8.50	10.00
IL								7.25	18.07
SD								8.00	10.00

Company	Number of Customers	Substation Capacity (Mva)	Number of Transformers	Substation Capacity (Mva/ 1,000 Customers)	Number of Transformers (Transformers/ 1,000 Customers)	Capacity Rank	Transformer Rank	Residential Customer Charge	Small Commercial Customer Charge
Northern States Power (Minnesota)	1,466,398	44,906	630	30.62	0.43	8	15		
MN								8.00	10.00
ND								14.50	16.75
SD								8.25	9.00
Northern States Power (Wisconsin)	257,668	9,180	281	35.63	1.09	5	7		
MI								9.00	11.50
WI								17.00	17.00
NorthWestern Energy LLC ^{2,3}	431,099	14,364	819	33.32	1.90	7	3		
MT								4.10	7.35
SD								6.00	10.00
Northwestern Wisconsin Elec Co ³	13,898	304	40	21.87	2.88	12	2		
WI								11.00	16.00
Superior Water and Light Co ³	14,782	345	6	23.34	0.41	10	16		
WI								9.00	10.00
Wisconsin Electric Power Co ²	1,122,784	25,026	641	22.29	0.57	11	13		
MI								12.00	25.00
WI								16.00	16.00
Wisconsin Power & Light Co ³	469,709	5,729	304	12.20	0.65	14	11		
WI								15.00	17.00
Wisconsin Public Service Corp	442,281	4,459	243	10.08	0.55	15	14		
WI								\$ 21.00	\$ 27.63

Unmetered?

Source: Company Tariffs; FERC Form 1.

¹ Black Hills Energy has fewer than 50 Montana customers, so customer charges were excluded.² Wyoming rates are limited to Yellowstone Park and thus excluded from the analysis.³ The lowest General Service rate is used due to lack of Small Commercial Service Rates on companies' tariffs.

Consolidated Water Power, North Central Power, Pioneer Power and Light, and Superior Water and Light were removed due to size
PacifiCorp was removed because much of its service territory is far from North Dakota
Dahlberg Light and Power does not file a FERC Form 1

Customers
Co 112
No 5447
Pic 2382

Prepared by: GO 5/9/2018
Checked by: TEM 5/11/2018

Capacity Transformers
56 2
112 2
112 2
112 2
56 1
25 1
200 2
112 2
56 1
112 2
112 2
400 2
168 3
Total
1633 24

Name of Respondent		This Report Is	Date of Report	Year/Period of Report	
Cheyenne Light, Fuel and Power Company		(1) ☐ An Original	(Mn. Dn. Yr.) 04/16/2018	End of 2017/24	
		(2) ☒ A Resubmission			
SUBSTATIONS					
1. Report below the information called for concerning substations of the respondent as of the end of the year.					
2. Substations which serve only one industrial or street railway customer should not be listed below.					
3. Substations with capacities of less than 15 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.					
4. Indicate in column (3) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (5).					
Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (in MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Corral	Dist. Unattended	115.00	24.00	
2	Chow Creek	Dist. Unattended	115.00	13.20	
3	Hill Top	Dist. Unattended	115.00	13.20	
4	Skylines/Dist	Dist. Unattended	115.00	13.20	
5	East Business Parks/Dist	Dist. Unattended	115.00	13.20	
6	Happy Jack	Dist. Unattended	115.00	24.00	
7	Wyotek 230 KV Sub	Trans. Unattended	230.00	60.00	13.20
8	Skylines/Trans	Trans. Unattended	115.00	13.20	
9	East Business Parks/Trans	Trans. Unattended	115.00	13.20	
10	North Range Business Park Sub/Trans	Trans. Unattended	115.00	24.00	
11	North Range Business Park Sub-Dist	Dist. Unattended	115.00	24.00	
12	South Cheyenne/Trans	Trans. Unattended	230.00	115.00	
13	Seren Ranch/Trans	Trans. Unattended	115.00	24.00	
14	Seren Ranch/Dist	Dist. Unattended	115.00	24.00	
15	Microsoft (Logistics Drive)	Dist. Unattended	115.00	24.00	
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent		This Report Is		Date of Report	Year/Period of Report	
Cheyenne Light, Fuel and Power Company		(1)	(2) (a) Original	(Mn. Dn. Yr.)	End of	
		(2)	A Resubmission	04/16/2018	2017/24	
SUBSTATIONS (continued)						
5. Show in columns (1), (2), and (3) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.						
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.						
Capacity of Substation (in Service) (in MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No. (i)
			Type of Equipment (j)	Number of Units (k)	Total Capacity (in MVA) (l)	
56	2					1
112	2					2
112	2					3
112	2					4
56	1					5
25	1					6
230	2					7
112	2					8
56	1					9
112	2					10
400	2					11
112	2					12
						13
						14
168	3					15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Capacity	Transformers
78	2
29	1
78	2
150	1
Total	6

Name of Respondent Superior Water, Light and Power Company		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/24	
SUBSTATIONS					
1. Report below the information called for concerning substations of the respondent as of the end of the year.					
2. Substations which serve only one industrial or street railway customer should not be listed below.					
3. Substations with capacities of less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.					
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).					
Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (in MVA) Primary (c) Secondary (d) Tertiary (e)		
1					
2					
3					
4					
5					
6	10 MVA or Above Capacity: Distribution				
7	Stinson Avenue	Unattended: Distrb	115.00	13.80	
8	Fairmount Park	Unattended: Distrb	115.00	13.80	
9	Winter Street	Unattended: Distrb	115.00	13.80	
10					
11	10 MVA or Above Capacity: Transmission				
12	Stinson Avenue	Unattended	115.00	161.00	13.80
13		Transmission			
14					
15	100MVA or Under Capacity: Switching Station				
16	Gordon	Switching Station	161.00	161.00	
17					
18					
19	Voltage (in KV)				
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Superior Water, Light and Power Company		This Report Is: (1) ☒ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2017/24	
SUBSTATIONS (Continued)					
5. Show in columns (f), (g), and (h) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.					
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.					
Capacity of Substation (in Service) (in MVA) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) Number of Units (j) Total Capacity (in MVA) (k)		Line No.
					1
					2
					3
					4
					5
					6
78	2				7
39	1				8
78	2				9
					10
					11
160	1		Phase Angle	5	200,000
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38
					39
					40

Capacity	Transformers
5	1
4	1
Total	2

Name of Respondent Pioneer Power and Light Company		This Report Is: (1) ☐ An Original (2) ☒ A Resubmission		Date of Report (Mo. Da. Yr) 04/05/2018	Year/Period of Report End of 2017/Q4
SUBSTATIONS					
1. Report below the information called for concerning substations of the respondent as of the end of the year. 2. Substations which serve only one industrial or street railway customer should not be listed below. 3. Substations with capacities of less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown. 4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).					
Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (in MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Westfield Substation				
2	Township of Westfield	Distribution	69.00	12.50	
3	Marquette County, Wisconsin	Unattended			
4					
5					
6	Grand Marsh Substation				
7	Township of New Chester	Distribution	69.00	12.50	
8	Adams County, Wisconsin	Unattended			
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Pioneer Power and Light Company		This Report Is: (1) ☐ An Original (2) ☒ A Resubmission		Date of Report (Mo. Da. Yr) 04/05/2018	Year/Period of Report End of 2017/Q4	
SUBSTATIONS (Continued)						
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity. 6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.						
Capacity of Substation (in Service) (in MVA) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (in MVA) (k)	
						1
						2
5	1					3
						4
						5
						6
4	1					7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Capacity Transformers

20 1
30 1
4 1
5 1
60 2
24 2
16 2
40 2
90 3
10 1
90 3
5 1
10 2
20 1
20 1
12 1
40 2
20 1
20 1
5 1
40 2
20 1
20 1
20 1
32 2
20 1
20 1
10 2
60 2
4 1
10 2
50 3
40 2
10 1
40 2
111 36
Total 99

Name of Respondent		This Report Is: (1) Original (2) A Resubmission	Date of Report (Mo. Da. Yr) 04/16/2016	Year/Period of Report End of 2017/04	
Madison Gas and Electric Company					
SUBSTATIONS					
1 Report below the information called for concerning substations of the respondent as of the end of the year. 2 Substations which serve only one industrial or street railway customer should not be listed below. 3 Substations with capacities of less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown. 4 Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).					
Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (in MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	American	Distribution (U)	136.00	69.00	13.60
2	Blackhawk	Distribution (U)	69.00	13.60	
3	Blackhawk	Distribution (U)	13.20	4.00	
4	Blackhawk	Distribution (U)	13.60	4.00	
5	Bount	Interconnected (U)	69.00	13.60	
6	Bount	Distribution (U)	13.20	4.00	
7	Bount	Distribution (U)	13.60	4.00	
8	Bount One	Distribution (U)	69.00	13.60	
9	Bount Spot	Distribution (U)	136.00	69.00	13.60
10	Bount Spot	Distribution (U)	69.00	13.60	
11	Bount Spot	Distribution (U)	13.20	4.16	
12	Bount Spot	Distribution (U)	13.20	4.00	
13	Cross Plains	Distribution (U)	69.00	13.60	
14	East Campus	Distribution (U)	69.00	13.60	
15	East Campus	Distribution (U)	69.00	4.00	
16	East Campus	Distribution (U)	13.20	4.00	
17	East Towne	Distribution (U)	69.00	13.60	
18	Farmite	Distribution (U)	69.00	13.60	
19	Flachburg	Interconnected (U)	136.00	69.00	13.60
20	Flachburg	Interconnected (U)	69.00	13.60	
21	Galesburg	Distribution (U)	69.00	13.60	
22	Halskamp	Distribution (U)	136.00	69.00	13.60
23	Halskamp	Distribution (U)	69.00	13.60	
24	Madison Unit	Distribution (U)	69.00	13.60	
25	Nine Springs	Interconnected (U)	69.00	13.60	
26	Nine Springs	Distribution (U)	69.00	4.00	
27	Nine Springs	Distribution (U)	13.20	4.00	
28	Nine Springs	Distribution (U)	69.00	13.60	
29	Owensboro	Distribution (U)	136.00	13.60	
30	Pleasant	Distribution (U)	69.00	13.60	
31	Pleasant	Distribution (U)	69.00	4.00	
32	Pleasant Branch	Distribution (U)	69.00	13.60	
33	Royter	Distribution (U)	136.00	69.00	13.60
34	Royter	Distribution (U)	69.00	4.00	
35	Rosin	Distribution (U)	136.00	69.00	13.60
36	Rosin	Distribution (U)	69.00	13.60	
37	Sprecher	Distribution (U)	136.00	69.00	13.60
38	Sprecher	Distribution (U)	136.00	13.60	
39	Sycamore	Interconnected (U)	69.00	13.60	
40	Syoma	Distribution (U)	136.00	69.00	13.60

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Name of Respondent		This Report Is:		Date of Report	Year/Period of Report
Madison Gas and Electric Company		(1) ☒ An Original	(2) ☐ A Resubmission	(Mo, Da, Yr) 04/16/2016	End of 2017/04
SUBSTATIONS					
1. Report below the information called for concerning substations of the respondent as of the end of the year:					
2. Substations which serve only one industrial or street railway customer should not be listed below.					
3. Substations with capacities of less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.					
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).					
Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (in MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Tokay	Distribution (U)	69.00	13.60	
2	University Hill Farm	Distribution (U)	13.20	4.00	
3	Walnut	Distribution (U)	69.00	13.60	
4	Walnut	Distribution (U)	69.00	13.60	
5	Walnut	Distribution (U)	13.60	4.00	
6	West Campus	Distribution (U)	13.20	4.00	
7	West Middleton	Distribution (U)	69.00	13.60	
8	West Towne	Distribution (U)	69.00	13.60	
9	Westport	Distribution (U)	69.00	13.60	
10	Wilgus	Distribution (U)	69.00	13.60	
11	16 - Substations < 10 Mva	Distribution (U)	13.20	4.00	
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
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31					
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35					
36					
37					
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39					
40					

FERC FORM NO. 1 (ED. 12-96)

Page 426.1

Name of Respondent		This Report Is: (1) Original (2) A Resubmission	Date of Report (Mo. Da. Yr) 04/16/2016	Year/Period of Report End of 2017/04	
Madison Gas and Electric Company					
SUBSTATIONS (Continued)					
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc., and auxiliary equipment for increasing capacity. 6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.					
Capacity of Substation (in Service) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT		Line No.
			Type of Equipment (i)	Number of Units (j)	
20	1		0	0	1
30	1		0	0	2
4	1		0	0	3
5	1		0	0	4
60	2		0	0	5
24	2		0	0	6
16	2		0	0	7
40	2		0	0	8
16	2		0	0	9
80	3	1	0	0	10
		1	0	0	11
		2	0	0	12
10	1	2	0	0	13
90	3		0	0	14
5	1		0	0	15
10	2		0	0	16
40	2		0	0	17
20	2		0	0	18
20	1		0	0	19
20	1		0	0	20
10	1		0	0	21
20	1		0	0	22
12	1		0	0	23
		1	0	0	24
40	2		0	0	25
		2	0	0	26
		4	0	0	27
20	1	1	0	0	28
20	1		0	0	29
5	1		0	0	30
40	2		0	0	31
20	1		0	0	32
5	1		0	0	33
20	1		0	0	34
20	1		0	0	35
20	1		0	0	36
30	2		0	0	37
20	1		0	0	38
30	2		0	0	39
20	1		0	0	40

FERC FORM NO. 1 (ED. 12-96)

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Name of Respondent		This Report Is: (1) Original (2) A Resubmission	Date of Report (Mo. Da. Yr) 04/16/2016	Year/Period of Report End of 2017/04	
Madison Gas and Electric Company					
SUBSTATIONS (Continued)					
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc., and auxiliary equipment for increasing capacity.					
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.					
Capacity of Substation (in Service) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT		Line No.
			Type of Equipment (i)	Number of Units (j)	
20	1		0	0	1
10	2		0	0	2
		1	0	0	3
60	2		0	0	4
4	1		0	0	5
10	2		0	0	6
50	3		0	0	7
40	2		0	0	8
10	1		0	0	9
40	2		0	0	10
111	36		0	0	11
					12
					13
					14
					15
					16
					17
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					36
					37
					38
					39
					40

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Capacity	Transformers
150	3
30	1
8	3
Total	7
188	7

Name of Respondent Consolidated Water Power Company		This Report Is: (1) ☐ An Original (2) ☒ A Resubmission		Date of Report (M/D, DA, Y) 03/28/2018	Year/Period of Report End of 2017 Q4
SUBSTATIONS					
1. Report below the information called for concerning substations of the respondent as of the end of the year. 2. Substations which serve only one industrial or street railway customer should not be listed below. 3. Substations with capacities of Less than 10 Mva except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown. 4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).					
Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (in Mva)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Grand Rapids	Transmission	115.00	48.00	
2	Rocky Run	Transmission	115.00	48.00	
3	Bron - Village	Distribution	46.00	12.47	
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
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21					
22					
23					
24					
25					
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27					
28					
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30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Consolidated Water Power Company		This Report Is: (1) ☐ An Original (2) ☒ A Resubmission		Date of Report (M/D, DA, Y) 03/28/2018	Year/Period of Report End of 2017 Q4	
SUBSTATIONS (Continued)						
5. Show in columns (f), (g), and (h) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity. 6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.						
Capacity of Substation (in Service) (in Mva) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (in Mva) (k)	
150	3					1
30	1					2
8	3	1				3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
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						20
						21
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						24
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						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Capacity Transformers[illegible]

Name of Respondent	Has Report to be Submitted to the State Supervisor	Date of Report (Month/Day/Year)	Year/Period of Report (End of 2017/24)	
State High Power, Inc.	Yes	7/7	2017/24	
1. Report before the information collected for conducting substitutions of the respondent as of the end of the year. 2. Substitutions among services only can be included in other columns. 3. Substitutions with replacement of Lines 10 to 10A except those saving contracts with energy for resale, may be accepted according to the contract. 4. Substitutions with replacement of Lines 10 to 10A except those saving contracts with energy for resale, may be accepted according to the contract. 5. Indicate in column (a) the functional character of each substitution, designating whether substitution in distribution and whether substitution in transmission. At the end of the table, summarize as to function the respective frequencies for the individual stations in column (b).				
Line	Name and location of Substation	Character of Substitution	Voltage (kV)	Secondary (MVA)
	(a)	(b)		
1	Spokane City, Spokane, ID	Dist. Unsubstituted	69.00	12.47
2	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	12.47
3	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	12.47
4	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	12.47
5	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
6	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
7	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
8	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
9	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
10	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
11	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
12	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
13	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
14	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
15	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
16	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
17	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
18	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
19	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
20	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
21	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
22	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
23	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
24	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
25	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
26	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
27	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
28	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
29	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
30	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
31	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
32	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
33	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
34	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
35	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
36	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
37	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
38	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
39	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
40	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
41	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
42	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
43	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
44	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
45	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
46	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
47	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
48	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
49	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
50	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
51	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
52	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
53	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
54	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
55	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
56	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
57	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
58	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
59	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
60	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
61	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
62	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
63	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
64	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
65	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
66	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
67	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
68	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
69	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
70	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
71	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
72	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
73	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
74	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
75	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
76	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
77	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
78	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
79	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
80	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
81	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
82	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
83	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
84	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
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87	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
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90	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
91	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
92	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
93	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
94	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
95	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
96	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
97	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
98	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
99	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
100	Spokane Falls, Spokane, ID	Dist. Unsubstituted	69.00	20.00
40	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
41	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
42	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
43	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
44	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
45	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
46	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
47	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
48	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
49	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
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56	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
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63	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
64	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
65	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
66	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
67	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
68	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
69	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
70	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
71	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
72	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
73	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
74	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
75	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
76	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
77	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
78	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
79	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
80	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
81	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
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92	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
93	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
94	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
95	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
96	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
97	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
98	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
99	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00
100	Idaho Falls Substation, Twin Springs, ID	Trans. Unsubstituted	230.00	69.00

Name of Respondent Black Hills Power, Inc.	This Report Is (1) Final or (2) Interim (3) A Supplement (4) Supplemental	Date of Report (Month, Day, Yr) 7 / 1	Year/Period of Report End of 2013/Q4		
1. Report below the information called for concerning substations of the respondent as of the end of the year.					
2. Substations which serve only one industrial or hotel (where customers should not be listed below).					
3. Substations with capacities of less than 10 MVA except those serving customers with energy for resale, may be grouped according to combined character, list the number of such substations that be shown.					
4. In column (3) the functional character of each substation, designating whether transmission or distribution area, whether attended or unattended. At the end of the year, summarize according to function the capacities reported for the individual stations in column (5).					
Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (in MVA)		
(1)	(2)	(3)	Primary (4)	Secondary (5)	Tertiary (6)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
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29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

[illegible][illegible]

Name of Respondent (Block H&A Form, Inc.)	What Report Is This Original File Substitution Of?	Date of Report (Mo. Da. Yr.)	Version/Report End of _____		
5. Show in column (1), (2), and (3) special equipment such as rotary converters, rectifiers, condensers, etc., and auxiliary equipment for converting power.					
6. Designate substitutions or major items of equipment based from others, jointly owned with others, or operated otherwise than by means of title ownership by the respondent. For any substitution or equipment operated on other basis, give name of lessee, date and period of lease, and arrival date. For any substitution or equipment operated other than by reason of title ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books and account. Specify in each case whether lessee, co-owner, or other party is an associated company for converting power.					
Capacity of Substation (in KVA or MW)	Number of Transformers in Service	Number of Spent Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT		Line No.
(1)	(2)	(3)	Type of Equipment	Number of Units	(4) (5)
			20 MW Base:		
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
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					17
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					29
					30
					31
					32
					33
					34
					35
					36
					37
					38
					39
					40

Capacity Transformers

15 1
 8 1
 8 1
 4 1
 4 1
 4 1
 4 1
 5 3
 5 1
 2 3
 5 1
 4 1
 5 1
 4 1
 4 1
 4 1
 4 1
 10 1
 5 1
 3 3
 4 1
 3 3
 2 1
 8 1
 8 2
 1 3
 30 1
 15 1
 10 1
 30 1
 30
 30
 30
 Total
 304 40

Name of Respondent Northwestern Wisconsin Electric Company		This Report Is: (1) ☐ An Original (2) ☒ A Resubmission		Date of Report (Mo, Da, Yr) 04/25/2018	Year/Period of Report End of 2017/Q4	
SUBSTATIONS (Continued)						
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity. 6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.						
Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
15	1					1
						2
8	1					3
8	1					4
4	1					5
4	1					6
4	1					7
4	1	1				8
4	1	1				9
5	3	1				10
5	1	3				11
2	3	1				12
5	1	1				13
4	1					14
5	1					15
4	1					16
4	1					17
4	1	1				18
						19
10	1					20
						21
5	1					22
3	3	3				23
4	1					24
3	3	1				25
2	1					26
8	1					27
8	2					28
1	3					29
						30
30	1					31
15	1					32
10	1					33
30	1	1				34
30		2				35
30		2				36
30						37
						38
						39
						40

	Name and Location	Voltage		Capacity of Substation	Number of Transformers	Number of Spare Transformers
		Primary	Secondary			
1	0 Subs under 10 MVA, MN	7				
2	2 Subs under 10 MVA, MN	14		67	2	
3	9 Subs under 10 MVA, MN	23		180	2	
4	44 Subs under 10 MVA, MN	34		142	3	
5	11 Subs under 10 MVA, MN	46		30	1	
6	6 Subs under 10 MVA, MN	115		10	1	
7	15th Avenue West-Duluth, MN	115	14	67	2	
8	Arrowhead-Adolph, MN	230	115	187	1	
9	Akeley-Akeley, MN	115	34	47	3	
10	Babbitt-Babbitt, MN	115	46	34	1	
11	Badoura-Badoura, MN	230	115	8	1	
12	Badoura-Badoura, MN	115	34	15	1	
13	Baxter-Brainerd, MN	115	34	10	1	
14	Bison 1,2,3,4-New Salem, ND	230				
15	Blackberry-Blackberry, MN	230	115	746	2	
16	Blanchard HE-North Little Falls, MN	115	34	187	1	
17	Brainerd-Brainerd, MN	115	34	43	2	
18	Calumet-Nashwauk, MN	230	14	34	1	
19	Canosia Road-Cloquet, MN	115	14	39	1	
20	Center, ND-Sq. Butte	230		39	1	
21	Clay Boswell-Cohasset, MN	115	23	39	1	
22	Cloquet-Cloquet, MN	115	14	73	2	
23	Colbyville-Duluth, MN	115	14	187	1	
24	Dog Lake-North Brainerd, MN	115	34	57	2	
25	Eagle Valley-Eagle Bend, MN	115	34	11	1	
26	Embarrass-Embarrass, MN	115	115	5	2	
27	Embarrass-Embarrass, MN	115	23	8	1	
28	Forbes-Forbes, MN	500	230			
29	Forbes-Forbes, MN	230	115	374	2	
30	Four Corners-Duluth, MN	115	14	10	1	
31	French River, MN	115	14	187	1	1
32	Gary-Duluth, MN	115	14	23	2	
33	Grand Rapids-Grand Rapids, MN	115	23	15	1	
34	Haines Road-Duluth, MN	115	14	30	1	
35	Hat trick-Eveleth	115	23	39	1	
36	Hewitt-Hewitt, MN	7	2	187	1	
37	Hibbing-Hibbing, MN	115	23	13	1	
38	Hilltop-Duluth, MN	230	115	13	1	
39	Hinckley East-Hinckley, MN	46	12	10	1	
40	Hinckley East-Hinckley, MN	69	46	39	1	
41	International Falls, MN	115	14			
42	International Falls, MN	115	115	13	5	
43	Lake Superior Paper, Inc. - Duluth, MN	115	14	24	20	4
44	Lake Superior Paper, Inc. - Duluth, MN	115	34	140	74	
45	Lind Greenway	115	23	40	13	
46	Little Falls-Little Falls, MN	115	34	35	6	
47	Little Fork-Little Fork, MN	230	115	107	3	
48	Long Prairie - Long Prairie, MN	115	34	746	2	1
49	M.L. Hibbard-Duluth, MN	115	14	34	1	
50	Mahtowa-Mahtowa, MN	115	23	39	1	
51	Mahtowa-Mahtowa, MN	115	46	167	1	
52	Maturi	115	23	34	1	
53	McCarthy Lake-Nashwauk, MN	230	14	35	1	
54	Minntac-Mt. Iron, MN	230	115			
55	Mud Lake, Brainerd, MN	230	115	746	2	
56	Nashwauk-Nashwauk, MN	115	23	65	2	
57	Pequot Lakes-North Pequot Lakes, MN	115	34			
58	Pepin Lake-Swanville, MN	115	34			
59	Pine River-Pine River, MN	115	34	39	1	
60	Platte River-Royalton, MN	115	34			
61	Ridgeview-Duluth, MN	115	14	8	1	
62	Riverton-Riverton, MN	230	115	65	3	
63	Riverton-Riverton, MN	115	34	62	2	
64	Sandstone-Sandstone, MN	69	46	20	1	
65	Sandstone-Sandstone, MN	46	12	39	1	
66	Scanlon HE - Scanlon, MN	23	14			
67	Scearcyville-Brainerd, MN	115		10	1	
68	Shannon-Hibbing, MN	230	115	672	1	
69	Silver Bay, Hill Side, MN	115	14	746	2	
70	S-Laskin-Aurora, MN	138	115	34	1	
71	S-Laskin-Aurora, MN	115	46	19	1	
72	S-Laskin-Aurora, MN	115	23	73	2	1
73	Swan Lake	115	34			
74	Swan Lake	115	14	67	2	
75	Taconite Harbor-Taconite Harbor, MN	138	115	39	1	
76	Taft-Grand Lake Township	115	34			
77	Thomson HE-Thomson, MN	115	46	78	2	
78	Thomson HE-Thomson, MN	115	14	187	1	

79	Tower, MN	115	46	6	1	
80	Tri-County	230		11	1	
81	Two Harbors, Two Harbors, MN	115	14	20	3	
82	Two Harbors Switching Station	115	14	19	1	
83	Verndale-Verndale, MN	115	34	45	2	
84	Virginia-Virginia, MN	115	46	39	1	
85	Virginia-Virginia, MN	115	23	45	3	
86	Wing River-Verndale, MN	230	115			
87	Zemple	230	115	374	2	
88	Zemple	115	23	10	1	
				8157	221	7

Comparison of Current and Proposed Class Return and RROR

Witness: Dismukes
Case No. PU-17-398
Schedule DED-##

	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Water Heating	Controlled Service Interruptible	Controlled Service Demand
Company's CCOSS										
Return	2.71%	2.07%	7.67%	8.72%	-3.42%	3.01%	1.88%	-0.90%	-1.16%	5.31%
Relative ROR	0.52	0.40	1.47	1.67	(0.66)	0.58	0.36	(0.17)	(0.22)	1.02
Alternative CCOSS										
Return	4.91%	1.44%	8.11%	7.22%	-5.42%	4.03%	2.75%	-3.42%	-4.67%	1.60%
Relative ROR	0.94	0.28	1.56	1.39	(1.04)	0.77	0.53	(0.66)	(0.90)	0.31

OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2018

LINE NO	ITEM	ALLOCATION	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Water Heating	Controlled Service Interruptible	Controlled Service Deferred
1	RATE BASE		354,191,795	125,874,811	8,479,201	88,428,075	90,600,482	313,267	8,217,318	3,262,553	3,755,746	22,051,030	3,209,311
2													
3	TOTAL AVAILABLE FOR RETURN		18,454,393	3,412,418	175,289	6,783,796	7,904,724	(10,715)	247,020	61,466	(33,919)	(256,217)	170,530
4													
5	RATE OF RETURN EARNED		5.21%	2.71%	2.07%	7.67%	8.72%	-3.42%	3.01%	1.88%	-0.90%	-1.16%	5.31%
6													
7	RATE OF RETURN REQUESTED		7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%
8													
9	OPERATING INCOME REQUIRED		28,229,086	10,032,222	675,792	7,047,718	7,220,858	24,967	654,920	260,026	299,333	1,757,467	255,782
10													
11	TOTAL AVAILABLE FOR RETURN		18,454,393	3,412,418	175,289	6,783,796	7,904,724	(10,715)	247,020	61,466	(33,919)	(256,217)	170,530
12													
13	OPERATING INCOME DEFECIENCY		9,774,693	6,619,804	500,503	263,921	(683,866)	35,683	407,900	198,560	333,252	2,013,684	85,252
14													
15	INCREMENTAL TAXES	GRCF = 1.607756	5,940,627	4,023,224	304,184	160,400	(415,623)	21,686	247,904	120,676	202,536	1,223,828	51,812
16													
17	REVENUE INCREASE REQUIRED		15,715,320	10,643,028	804,687	424,321	(1,099,489)	57,369	655,804	319,236	535,787	3,237,513	137,064
18													
19	PERCENTAGE INCREASE CCROSS		10.61%	22.08%	30.80%	1.09%	-2.55%	97.10%	22.86%	26.51%	49.38%	38.55%	9.00%
20													
21	Present Retail Revenue		\$148,071,951	\$48,209,916	2,612,688	38,950,615	43,160,710	59,083	2,869,144	1,203,986	1,085,033	8,397,154	1,523,622
22	Percentage Increase requested		10.61%	13.70%	13.70%	8.27%	8.26%	19.00%	13.00%	13.00%	13.70%	13.70%	8.26%
23	Revenue increase required		\$15,715,320	\$6,604,758	\$357,938	\$3,221,905	\$3,565,075	\$11,226	\$372,989	\$156,518	\$148,650	\$1,150,410	\$125,851

Account Description	Total North Dakota Distribution	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interrupt	Controlled Service Deferred
Rate Base											
Total Electric Distribution Plant	\$ 758,395,145	\$ 239,241,818	\$ 18,849,481	\$ 184,764,841	\$ 207,391,132	\$ 829,040	\$ 17,065,520	\$ 6,628,209	\$ 9,966,821	\$ 65,093,431	\$ 8,564,852
Less: Depreciation Reserve	\$ (304,752,303)	\$ (96,829,889)	\$ (7,649,350)	\$ (74,177,032)	\$ (83,021,003)	\$ (338,208)	\$ (7,254,581)	\$ (2,699,964)	\$ (4,064,285)	\$ (25,266,858)	\$ (3,451,132)
Total Net Electric Distribution Plant	\$ 453,642,842	\$ 142,411,929	\$ 11,200,130	\$ 110,587,809	\$ 124,370,129	\$ 490,832	\$ 9,810,939	\$ 3,928,245	\$ 5,902,536	\$ 39,826,573	\$ 5,113,720
Plus: Rate Base Additions	\$ 16,593,419	\$ 5,259,318	\$ 392,664	\$ 4,083,450	\$ 4,697,751	\$ 15,229	\$ 357,461	\$ 148,991	\$ 194,256	\$ 1,265,414	\$ 178,884
Less: Rate Base Deductions	\$ (116,044,466)	\$ (36,429,796)	\$ (2,865,058)	\$ (28,289,002)	\$ (31,814,599)	\$ (125,558)	\$ (2,509,695)	\$ (1,004,868)	\$ (1,509,903)	\$ (10,187,868)	\$ (1,308,119)
Total Rate Base	\$ 354,191,795	\$ 111,241,451	\$ 8,727,736	\$ 86,382,257	\$ 97,253,281	\$ 380,503	\$ 7,658,705	\$ 3,072,368	\$ 4,586,888	\$ 30,904,119	\$ 3,984,485
Operating Income											
Electric Operating Revenues											
Retail Sales	\$ 148,071,951	\$ 48,209,916	\$ 2,612,688	\$ 38,950,615	\$ 43,160,710	\$ 59,083	\$ 2,869,144	\$ 1,203,986	\$ 1,085,033	\$ 8,397,154	\$ 1,523,622
Other Operating Revenues	\$ 10,047,294	\$ 3,344,556	\$ 244,318	\$ 2,425,952	\$ 2,643,490	\$ 10,663	\$ 208,870	\$ 87,271	\$ 125,577	\$ 847,695	\$ 108,900
Total Electric Operating Revenues	\$ 158,119,244	\$ 51,554,472	\$ 2,857,006	\$ 41,376,567	\$ 45,804,200	\$ 69,746	\$ 3,078,014	\$ 1,291,258	\$ 1,210,610	\$ 9,244,848	\$ 1,632,523
Electric Operating Expenses											
Operating and Maintenance Expenses	\$ 108,238,348	\$ 36,179,687	\$ 2,137,109	\$ 25,459,059	\$ 29,189,649	\$ 78,658	\$ 2,139,562	\$ 966,823	\$ 1,171,046	\$ 9,626,049	\$ 1,290,707
Depreciation & Amortization Expense	\$ 21,425,301	\$ 6,934,831	\$ 513,860	\$ 5,211,827	\$ 5,864,742	\$ 21,318	\$ 460,292	\$ 191,612	\$ 265,839	\$ 1,722,923	\$ 238,058
General Taxes	\$ 4,905,891	\$ 1,540,105	\$ 121,123	\$ 1,195,945	\$ 1,344,993	\$ 5,308	\$ 106,100	\$ 42,482	\$ 63,833	\$ 430,702	\$ 55,302
Investment Tax Credit	\$ (526,207)	\$ (165,996)	\$ (13,079)	\$ (128,198)	\$ (143,897)	\$ (575)	\$ (11,841)	\$ (4,599)	\$ (6,915)	\$ (45,165)	\$ (5,943)
Total Income Taxes	\$ 5,095,310	\$ 1,433,177	\$ (40,442)	\$ 2,504,202	\$ 2,383,568	\$ (14,907)	\$ 63,778	\$ 5,991	\$ (133,384)	\$ (1,091,485)	\$ (15,188)
Deferred Income Taxes	\$ 1,317,383	\$ 413,566	\$ 32,525	\$ 321,148	\$ 361,172	\$ 1,425	\$ 28,491	\$ 11,408	\$ 17,141	\$ 115,657	\$ 14,850
Total Electric Operating Expenses	\$ 140,456,028	\$ 46,335,369	\$ 2,751,097	\$ 34,563,984	\$ 39,000,227	\$ 91,227	\$ 2,786,382	\$ 1,213,716	\$ 1,377,560	\$ 10,758,681	\$ 1,577,786
Total Operating Income	\$ 18,454,393	\$ 5,466,673	\$ 125,356	\$ 7,005,534	\$ 7,021,249	\$ (20,631)	\$ 308,283	\$ 84,350	\$ (156,724)	\$ (1,443,341)	\$ 63,645
Rate of Return on Rate Base ("ROR")	5.21%	4.91%	1.44%	8.11%	7.22%	-5.42%	4.03%	2.75%	-3.42%	-4.67%	1.60%
Relative Rate of Return ("RROR")	1.00	0.94	0.28	1.56	1.39	(1.04)	0.77	0.53	(0.66)	(0.90)	0.31

Source:

Prepared by: TEM 5/9/2018
Checked by: JAM 5/14/18
Edited by: JAM
Checked by: GO 5/17/2018

Class	Proposed Revenue as a Percent of Marginal Costs
Residential	Need to update when available
Farms	
General Service	
Large General Service	
Irrigation	
Lighting	
OPA	
Controlled Service Water Heating	
Controlled Service Interruptible	
Controlled Service Deferred	
Total	

	4CP Demand (KW)	Demand Ratio	Average Energy (KW)	Average Energy Ratio	Energy	Demand	Total Allocation Factor
Residential	73140	0.21605					
Residential Demand Control	19078	0.05636					
Total Residential	92218	0.27241	63320	0.280022	0.176134	0.101064	0.277197
Water Controlled Service - Heating	3236	0.00956	1940	0.008581	0.005397	0.003546	0.008943
Farm	6258	0.01849	3721	0.016458	0.010352	0.006859	0.017210
General Service - under 20 kW	15642	0.04621					
General Service - over 20 kW	63372	0.18720					
General Service - Time of Use	15	0.00004					
Total General Service	79029	0.23345	50941	0.225279	0.1417	0.08661	0.22831
Large General Service - Primary	22445	0.06630					
Large General Service - Transmission	42	0.00012					
Large General Service - Secondary	70341	0.20779					
Total Large General Service	92827	0.27421	72792	0.321909	0.202481	0.101732	0.304213
Small Dual Fuel	39421	0.11645					
Large Dual Fuel	16761	0.04951					
Total Controlled Service Interruptible	56182	0.16596	25488	0.112715	0.070898	0.061571	0.132469
Fixed Time of Delivery	272	0.00080					
Controlled Service - Deferred Load	4971	0.01468					
Total Deferred Load Control	5242	0.01549	3484	0.015407	0.009691	0.005745	0.015436
Irrigation	0	0.00000	101	0.000448	0.000282	0.000000	0.000282
Other Public Authorities	2250	0.00665	2080	0.009199	0.005786	0.002466	0.008252
Area Lighting	549	0.00162					
Street Lighting	736	0.00217					
Total Lighting	1284	0.00379	2257	0.009982	0.006278	0.001407	0.007686
	338,525	1.00	226,125	1.00	0.6290	0.3710	1.0000

Energy	Load Factor per response to ND-PSC-11.17	62.90%
Demand	1-load factor	37.10%

Prepared by: JAM 5/5/18
Checked by: MD 5/7/2018

	12CP Demand (KW)	12CP Allocation Factor
Residential	59805	0.2165
Residential Demand Control	11412	0.0413
Total Residential	71218	0.2579
Water Controlled Service - Heating	2265	0.0082
Farm	6021	0.0218
General Service - under 20 kW	14963	0.0542
General Service - over 20 kW	57173	0.2070
General Service - Time of Use	19	0.0001
Total General Service	72155	0.2613
Large General Service - Primary	22742	0.0823
Large General Service - Transmission	31	0.0001
Large General Service - Secondary	67515	0.2445
Total Large General Service	90288	0.3269
Small Dual Fuel	19894	0.0720
Large Dual Fuel	9277	0.0336
Total Controlled Service Interruptible	29170	0.1056
Fixed Time of Delivery	131	0.0005
Controlled Service - Deferred Load	2353	0.0085
Total Deferred Load Control	2484	0.0090
Irrigation	181	0.0007
Other Public Authorities	1989	0.0072
Area Lighting	174	0.0006
Street Lighting	233	0.0008
Total Lighting	408	0.0015
 Total	 276,177	 1.00

Prepared by: JAM 5/5/18

Checked by: MD 5/7/2018

	Class NCP Demand (KW)	Class NCP Demand Allocation Factor	Sum of Customer Max NCP Demand (KW)	Sum of Customer Max NCP Demand Allocation Factor	NCP Allocation Factor
Residential	94171	0.2153	232966	0.3026	0.2590
Residential Demand Control	26642	0.0609	45262	0.0588	0.0599
Total Residential	120813	0.2762	278228	0.3614	0.3188
Water Controlled Service - Heating	6414	0.0147	21366	0.0278	0.0212
Farm	12324	0.0282	21958	0.0285	0.0283
General Service - under 20 kW	20325	0.0465	36699	0.0477	0.0471
General Service - over 20 kW	69877	0.1597	124669	0.1620	0.1608
General Service - Time of Use	18	0.0000	18	0.0000	0.0000
Total General Service	90220	0.2063	161386	0.2097	0.2080
Large General Service - Primary	27304	0.0624	39831	0.0517	0.0571
Large General Service - Transmission	250	0.0006	250	0.0003	0.0004
Large General Service - Secondary	71285	0.1630	80564	0.1047	0.1338
Total Large General Service	98839	0.2260	120645	0.1567	0.1913
Small Dual Fuel	49173	0.1124	83651	0.1087	0.1105
Large Dual Fuel	25278	0.0578	35882	0.0466	0.0522
Total Controlled Service Interruptible	74451	0.1702	119533	0.1553	0.1627
Fixed Time of Delivery	16156	0.0369	18116	0.0235	0.0302
Controlled Service - Deferred Load	8051	0.0184	13969	0.0181	0.0183
Total Deferred Load Control	24207	0.0553	32085	0.0417	0.0485
Irrigation	1386	0.0032	2082	0.0027	0.0029
Other Public Authorities	3081	0.0070	7167	0.0093	0.0082
Area Lighting	2623	0.0060	2263	0.0029	0.0045
Street Lighting	3069	0.0070	3069	0.0040	0.0055
Total Lighting	5692	0.0130	5332	0.0069	0.0100
 Total	 437,427	 1.0000	 769,782	 1.0000	 1.00

Prepared by: JAM 5/5/18
Modified by: MD 5/7/2018

	Sum of Custom Max NCP Demand (KW)	Sum of Customer Max NCP Allocation Factor
Residential	232966	0.3026
Residential Demand Control	45262	0.0588
Total Residential	278228	0.3614
Water Controlled Service - Heating	21366	0.0278
Farm	21958	0.0285
General Service - under 20 kW	36699	0.0477
General Service - over 20 kW	124669	0.1620
General Service - Time of Use	18	0.0000
Total General Service	161386	0.2097
Large General Service - Primary	39831	0.0517
Large General Service - Transmission	250	0.0003
Large General Service - Secondary	80564	0.1047
Total Large General Service	120645	0.1567
Small Dual Fuel	83651	0.1087
Large Dual Fuel	35882	0.0466
Total Controlled Service Interruptible	119533	0.1553
Fixed Time of Delivery	18116	0.0235
Controlled Service - Deferred Load	13969	0.0181
Total Deferred Load Control	32085	0.0417
Irrigation	2082	0.0027
Other Public Authorities	7167	0.0093
Area Lighting	2263	0.0029
Street Lighting	3069	0.0040
Total Lighting	5332	0.0069
 Total	 769,782	 1.00

Prepared by: JAM 5/5/18

Checked by: MD 5/7/2018

	Class NCP Demand (KW)	Class NCP Allocation Factor
Residential	94171	0.2153
Residential Demand Control	26642	0.0609
Total Residential	120813	0.2762
Water Controlled Service - Heating	6414	0.0147
Farm	12324	0.0282
General Service - under 20 kW	20325	0.0465
General Service - over 20 kW	69877	0.1597
General Service - Time of Use	18	0.0000
Total General Service	90220	0.2063
Large General Service - Primary	27304	0.0624
Large General Service - Transmission	250	0.0006
Large General Service - Secondary	71285	0.1630
Total Large General Service	98839	0.2260
Small Dual Fuel	49173	0.1124
Large Dual Fuel	25278	0.0578
Total Controlled Service Interruptible	74451	0.1702
Fixed Time of Delivery	16156	0.0369
Controlled Service - Deferred Load	8051	0.0184
Total Deferred Load Control	24207	0.0553
Irrigation	1386	0.0032
Other Public Authorities	3081	0.0070
Area Lighting	2623	0.0060
Street Lighting	3069	0.0070
Total Lighting	5692	0.0130
 Total	 437,427	 1.00

Prepared by: JAM 5/5/18

Checked by: MD 5/7/2018

Line Transformer (low side) - metered data

	PRI/SEC	Load Research Group	Maximum kW
Non Coincident Peak	S	Residential	232,966
Non Coincident Peak	S	Residential Demand Control	45,262
Non Coincident Peak	S	Water Controlled Service - Heating	21,366
Non Coincident Peak	S	Farm	21,958
Non Coincident Peak	S	General Service - under 20 kW	36,699
Non Coincident Peak	S	General Service - over 20 kW	124,669
Non Coincident Peak	P	Large General Service - Primary	39,831
Non Coincident Peak	T	Large General Service - Transmission	250
Non Coincident Peak	S	Large General Service - Secondary	80,564
Non Coincident Peak	S	Fixed Time of Delivery	18,116
Non Coincident Peak	S	Small Dual Fuel	83,651
Non Coincident Peak	S	Large Dual Fuel	35,882
Non Coincident Peak	S	Controlled Service - Deferred Load	13,969
Non Coincident Peak	S	General Service - Time of Use	18
Non Coincident Peak	S	Irrigation	2,082
Non Coincident Peak	S	Other Public Authorities	7,167
Non Coincident Peak	S	Area Lighting	2,263
Non Coincident Peak	S	Street Lighting	3,069

	TOTAL			GENERAL	LARGE GENERAL		OUTDOOR		CONTROLLED	CONTROLLED	CONTROLLED	
	NORTH DAKOTA	RESIDENTIAL	FARMS	SERVICE	SERVICE	IRRIGATION	LIGHTING	OPA	WATER HEATING	SERVICE INTERRUPT	SERVICE DEFERRED	
MWH	1980855	554682	32600	446245	637656		888	19772	18222	16997	223273	30520

Losses:

Secondary
Distribution to
Generation 0.111450031Primary Distribution
to Generation 0.107573523
Transmission to
Generation 0.050368972

Month	Residential	Residential		Water Heater	Farm	General Service					Fixed Time of Delivery	Dual Fuel		Deferred Load	Commercial Time of Use	Irrigation	Other Public Authority	Area Lights	Street Lights
		Demand Control				Under 20 kW	Over 20 kW	Primary	Transmission	Secondary		Small	Large						
January 2016	80,056	23,765	3,436	3,462		14,862	54,757	20,645	-	60,308	424	48,898	21,910	6,963	11	-	2,190	1,975	2,647
February 2016	69,136	20,023	2,192	2,904		14,827	51,461	20,566	-	59,243	317	42,735	20,064	6,149	11	-	2,302	-	-
March 2016	59,499	16,798	2,366	2,739		13,671	55,170	20,453	158	59,646	-	33,503	16,599	4,830	6	-	2,446	-	-
April 2016	50,523	14,707	2,272	2,475		12,732	48,571	21,415	-	57,053	256	25,733	14,120	3,739	11	-	2,066	-	-
May 2016	40,074	5,813	1,199	2,050		16,321	51,722	22,281	106	61,117	22	4,564	2,841	447	16	95	2,015	-	-
June 2016	65,833	6,973	1,324	2,366		17,692	43,809	19,037	108	62,063	32	5,771	3,078	461	17	1,198	2,172	-	-
July 2016	66,150	8,062	1,175	2,342		18,231	51,978	26,591	-	70,600	14	6,431	3,252	523	17	298	2,207	-	-
August 2016	80,563	7,959	1,439	3,031		18,090	43,332	24,105	-	66,148	16	6,911	3,319	511	17	385	2,308	-	-
September 2016	45,617	5,207	1,240	3,988		17,524	54,651	24,491	-	61,398	24	3,655	4,624	387	16	77	2,051	-	-
October 2016	43,194	11,049	1,662	9,038		10,693	63,607	23,520	-	55,717	57	19,833	12,391	2,333	10	2	1,806	-	-
November 2016	46,521	14,053	2,180	6,234		14,394	59,505	24,325	-	62,664	228	27,056	17,838	3,742	10	-	2,299	-	-
December 2016	69,423	22,843	2,363	6,414		19,002	64,985	23,051	-	61,231	520	44,222	24,038	6,755	10	-	2,543	-	-

2016 Production CP with losses

Month	Residential	Residential		Water Heater	Farm	General Service					Fixed Time of Delivery	Dual Fuel		Deferred Load	Commercial Time of Use	Irrigation	Other Public Authority	Area Lights	Street Lights
		Demand Control				Under 20 kW	Over 20 kW	Primary	Transmission	Secondary		Small	Large						
January 2016	88,978	26,414	3,819	3,848		16,518	60,860	22,866	-	67,029	471	54,348	24,352	7,739	12	-	2,434	2,195	2,942
February 2016	76,841	22,255	2,436	3,228		16,479	57,196	22,778	-	65,846	352	47,498	22,300	6,834	12	-	2,559	-	-
March 2016	66,130	18,670	2,630	3,044		15,195	61,319	22,653	166	66,294	-	37,237	18,449	5,368	7	-	2,719	-	-
April 2016	56,154	16,346	2,525	2,751		14,151	53,984	23,719	-	63,412	285	28,601	15,694	4,156	12	-	2,296	-	-
May 2016	44,540	6,461	1,333	2,278		18,140	57,486	24,678	111	67,928	24	5,073	3,158	497	18	106	2,240	-	-
June 2016	73,170	7,750	1,472	2,630		19,664	48,692	21,085	113	68,980	36	6,414	3,421	512	19	1,332	2,414	-	-
July 2016	72,522	8,961	1,306	2,603		20,263	57,771	29,451	-	78,468	16	7,148	3,614	581	19	331	2,453	-	-
August 2016	89,542	8,857	1,599	3,369		20,106	48,161	26,698	-	73,520	18	7,681	3,689	568	19	428	2,565	-	-
September 2016	50,701	5,787	1,378	4,432		19,477	60,742	27,126	-	68,241	27	4,062	5,139	430	18	86	2,280	-	-
October 2016	48,008	12,280	1,847	10,045		11,885	70,696	26,050	-	61,927	63	22,043	13,772	2,593	11	2	2,007	-	-
November 2016	51,706	15,619	2,423	6,929		15,932	66,137	26,942	-	58,522	253	30,071	19,826	4,159	11	-	2,555	-	-
December 2016	77,160	25,389	2,626	7,129		21,120	72,228	25,531	-	68,055	578	49,151	26,717	7,508	11	-	2,826	-	-

2016
Total
CP384,825
346,614
319,881
284,086
234,071
257,704
286,507
286,820
249,926
283,229
301,085
386,029

2016 Production CP with losses

Month	Residential	Residential		Water Heater	Farm	General Service					Fixed Time of Delivery	Dual Fuel		Deferred Load	Commercial Time of Use	Irrigation	Other Public Authority	Area Lights	Street Lights
		Demand Control				Under 20 kW	Over 20 kW	Primary	Transmission	Secondary		Small	Large						
January 2016	84,214	21,737	4,294	5,585		14,911	61,316	21,879	-	70,576	365	45,527	17,781	5,606	17	-	2,079	2,195	2,942
February 2016	72,727	18,315	2,739	4,684		14,876	57,625	21,795	-	69,330	273	39,789	16,283	4,950	17	-	2,185	-	-
March 2016	62,589	15,365	2,957	4,418		13,716	61,778	21,675	166	69,801	-	31,194	13,471	3,889	9	-	2,322	-	-
April 2016	53,147	13,452	2,839	3,992		12,774	54,389	22,695	-	66,767	221	23,959	11,459	3,010	17	-	1,961	-	-
May 2016	42,156	5,317	1,498	3,307		16,375	57,917	23,613	111	71,523	19	4,249	2,306	360	25	106	1,913	-	-
June 2016	69,252	6,378	1,655	3,817		17,750	49,056	20,175	113	72,630	28	5,373	2,498	371	26	1,332	2,062	-	-
July 2016	69,586	7,374	1,468	3,778		18,291	58,204	28,180	-	82,620	12	5,988	2,639	421	26	331	2,095	-	-
August 2016	84,748	7,289	1,798	4,889		18,150	48,522	25,546	-	77,410	14	6,435	2,694	411	26	428	2,191	-	-
September 2016	47,886	4,763	1,550	6,433		17,582	61,197	25,855	-	71,882	21	3,403	3,753	312	25	86	1,947	-	-
October 2016	45,438	10,106	2,077	14,579		10,728	71,226	24,926	-	65,203	49	18,466	10,056	1,878	16	2	1,714	-	-
November 2016	48,937	12,854	2,724	10,056		14,381	66,632	25,779	-	61,619	196	25,191	14,477	3,013	16	-	2,182	-	-
December 2016	73,029	20,894	2,953	10,346		19,065	72,769	24,429	-	71,656	448	41,174	19,508	5,438	16	-	2,414	-	-

2018
Adjusted
Total CP361,024
325,588
303,350
270,682
230,795
252,516
281,013
280,551
246,865
276,464
288,057
364,139

Month	Residential	Residential		Water Heater	Farm	General Service					Fixed Time of Delivery	Dual Fuel		Deferred Load	Commercial Time of Use	Irrigation	Other Public Authority	Area Lights	Street Lights
		Demand Control				Under 20 kW	Over 20 kW	Primary	Transmission	Secondary		Small	Large						
4CP	73,140	19,078	3,236	6,258		15,642	63,372	22,445	42	70,341	272	39,421	16,761	4,971	15	-	2,250	549	736

338,525

Losses:

Secondary
Distribution to
Transmission 0.058152002Primary Distribution
to Transmission 0.054461387
Transmission to
Generation 0.050368972

Month	Residential	Residential		Water Heater	Farm	General Service					Fixed Time of Delivery	Dual Fuel		Deferred Load	Commercial Time of Use	Irrigation	Other Public Authority	Area Lights	Street Lights
		Demand Control				Under 20 kW	Over 20 kW	Primary	Transmission	Secondary		Small	Large						
January 2016	80,056	23,765	3,436	3,462		14,862	54,757	20,645	-	60,308	424	48,898	21,910	6,963	11	-	2,190	1,975	2,647
February 2016	69,136	20,023	2,192	2,904		14,827	51,461	20,566	-	59,243	317	42,735	20,064	6,149	11	-	2,302	-	-
March 2016	59,499	16,798	2,366	2,739		13,671	55,170	20,453	158	59,646	-	33,503	16,599	4,830	6	-	2,446	-	-
April 2016	50,523	14,707	2,272	2,475		12,732	48,571	21,415	-	57,053	256	25,733	14,120	3,729	11	-	2,066	-	-
May 2016	40,074	5,813	1,199	2,050		16,321	51,722	22,281	106	61,117	22	4,564	2,841	447	16	95	2,015	-	-
June 2016	65,833	6,973	1,324	2,366		17,692	43,809	19,037	108	62,063	32	5,771	3,078	461	17	1,198	2,172	-	-
July 2016	66,150	8,062	1,175	2,342		18,231	51,978	26,591	-	70,600	14	6,431	3,252	523	17	298	2,207	-	-
August 2016	80,563	7,969	1,439	3,031		18,090	43,332	24,105	-	66,148	16	6,911	3,319	511	17	385	2,308	-	-
September 2016	45,617	5,207	1,240	3,988		17,524	54,651	24,491	-	61,398	24	3,655	4,624	387	16	77	2,051	-	-
October 2016	43,194	11,049	1,662	9,038		10,693	63,607	23,520	-	55,717	57	19,833	12,391	2,333	10	2	1,806	-	-
November 2016	46,521	14,053	2,180	6,234		14,334	59,505	24,325	-	62,664	238	27,056	17,838	3,742	10	-	2,259	-	-
December 2016	69,423	22,843	2,363	6,414		19,002	64,985	23,051	-	61,231	520	44,222	24,038	6,755	10	-	2,543	-	-

2016 Transmission CP with losses

Month	Residential	Residential		Water Heater	Farm	General Service					Fixed Time of Delivery	Dual Fuel		Deferred Load	Commercial Time of Use	Irrigation	Other Public Authority	Area Lights	Street Lights
		Demand Control				Under 20 kW	Over 20 kW	Primary	Transmission	Secondary		Small	Large						
January 2016	84,711	25,147	3,636	3,663		15,726	57,941	21,769	-	63,815	449	51,742	23,184	7,368	12	-	2,317	2,090	2,801
February 2016	73,156	21,187	2,319	3,073		15,689	54,454	21,686	-	62,688	335	45,220	21,231	6,507	12	-	2,436	-	-
March 2016	62,959	17,775	2,504	2,898		14,466	58,378	21,567	158	63,115	-	35,451	17,564	5,111	6	-	2,588	-	-
April 2016	53,461	15,562	2,404	2,619		13,472	51,396	22,581	-	60,371	271	27,229	14,941	3,956	12	-	2,186	-	-
May 2016	42,404	6,151	1,269	2,169		17,270	54,730	23,494	106	64,671	23	4,829	3,006	473	17	101	2,132	-	-
June 2016	69,661	1,401	2,504			18,721	46,357	20,074	108	65,672	34	6,107	3,257	488	18	1,268	2,298	-	-
July 2016	69,997	8,531	1,243	2,478		19,291	55,001	28,039	-	74,706	15	6,805	3,441	553	18	315	2,335	-	-
August 2016	85,248	8,432	1,523	3,207		19,142	45,852	25,418	-	69,995	17	7,313	3,512	541	18	407	2,442	-	-
September 2016	48,270	5,510	1,312	4,220		18,543	57,829	25,825	-	64,968	25	3,868	4,893	410	17	81	2,170	-	-
October 2016	45,706	11,692	1,759	9,564		11,315	67,306	24,801	-	58,957	60	20,986	13,112	2,469	11	2	1,911	-	-
November 2016	49,226	14,670	2,307	6,597		15,168	62,965	25,650	-	55,716	241	28,629	18,875	3,960	11	-	2,433	-	-
December 2016	73,460	24,171	2,500	6,787		20,107	68,764	24,306	-	64,792	550	46,794	25,436	7,148	11	-	2,691	-	-

2016
Total
CP366,371
329,993
304,540
270,461
222,845
245,346
272,768
273,067
237,941
269,651
286,646
367,517

2018 Transmission CP with losses

Month	Residential	Residential		Water Heater	Farm	General Service					Fixed Time of Delivery	Dual Fuel		Deferred Load	Commercial Time of Use	Irrigation	Other Public Authority	Area Lights	Street Lights
		Demand Control				Under 20 kW	Over 20 kW	Primary	Transmission	Secondary		Small	Large						
January 2016	80,176	20,695	4,088	5,317		14,196	58,375	20,830	-	67,192	348	43,344	16,929	5,337	16	-	1,979	2,090	2,801
February 2016	69,340	17,436	2,608	4,460		14,163	54,862	20,750	-	66,005	260	37,881	15,502	4,713	16	-	2,080	-	-
March 2016	59,588	14,628	2,815	4,206		13,058	58,816	20,636	158	66,454	-	29,698	12,825	3,702	9	-	2,211	-	-
April 2016	50,599	12,807	2,703	3,801		12,161	51,781	21,607	-	63,565	210	22,810	10,910	2,866	16	-	1,867	-	-
May 2016	40,134	5,062	1,427	3,148		15,590	55,140	22,480	106	68,093	18	4,046	2,195	343	24	101	1,821	-	-
June 2016	65,932	6,072	1,575	3,634		16,899	46,704	19,207	108	69,147	26	5,116	2,378	353	25	1,268	1,963	-	-
July 2016	66,249	7,021	1,398	3,597		17,414	55,413	26,829	-	78,659	11	5,701	2,513	401	25	315	1,995	-	-
August 2016	80,684	6,940	1,712	4,655		17,279	46,195	24,321	-	73,698	13	6,126	2,564	392	25	407	2,086	-	-
September 2016	45,685	4,534	1,475	6,125		16,739	58,262	24,710	-	68,406	20	3,240	3,573	287	24	81	1,854	-	-
October 2016	43,259	9,622	1,977	13,880		10,214	67,810	23,730	-	62,077	47	17,580	9,574	1,788	15	2	1,632	-	-
November 2016	46,591	12,238	2,594	9,574		13,692	63,437	24,543	-	58,664	187	23,983	13,782	2,868	15	-	2,078	-	-
December 2016	69,527	19,892	2,812	9,850		18,150	69,279	23,257	-	68,220	426	39,199	18,573	5,178	15	-	2,298	-	-

2018
Adjusted
Total CP343,713
309,976
288,804
257,703
219,726
240,407
267,541
267,097
238,025
263,207
274,246
346,676

	Residential	Residential		Water Heater	Farm	General Service					Fixed Time of Delivery	Dual Fuel		Deferred Load	Commercial Time of Use	Irrigation	Other Public Authority	Area Lights	Street Lights
		Demand Control				Under 20 kW	Over 20 kW	Primary	Transmission	Secondary		Small	Large						
4CP	69,633	18,163	3,081	5,958		14,892	60,333	21,368	40	66,968	259	37,531	15,957	4,733	14	-	2,142	523	700
12CP	59,805	11,412	2,265	6,021		14,963	57,173	22,742	31	67,515	131	19,894	9,277	2,353	19	181	1,989	174	233

322,292
276,177

Transmission			2016		2018 TY	
		System Peak Date/Time:	12/15/2016 9:00		12/15/2018 9:00	
	PRI/SEC	Load Research Group	Actual	Actual + Losses	Actual	Actual + Losses
Coincident Peak	S	Residential	69,423	73,460	65,706	69,527
Coincident Peak	S	Residential Demand Control	22,843	24,171	18,799	19,892
Coincident Peak	S	Water Controlled Service - Heating	2,363	2,500	2,657	2,812
Coincident Peak	S	Farm	6,414	6,787	9,309	9,850
Coincident Peak	S	General Service - under 20 kW	19,002	20,107	17,153	18,150
Coincident Peak	S	General Service - over 20 kW	64,985	68,764	65,472	69,279
Coincident Peak	P	Large General Service - Primary	23,051	24,306	22,056	23,257
Coincident Peak	T	Large General Service - Transmission	-	-	-	-
Coincident Peak	S	Large General Service - Secondary	61,231	64,792	64,471	68,220
Coincident Peak	S	Fixed Time of Delivery	520	550	403	426
Coincident Peak	S	Small Dual Fuel	44,222	46,794	37,045	39,199
Coincident Peak	S	Large Dual Fuel	24,038	25,436	17,552	18,573
Coincident Peak	S	Controlled Service - Deferred Load	6,755	7,148	4,893	5,178
Coincident Peak	S	General Service - Time of Use	10	11	14	15
Coincident Peak	S	Irrigation	-	-	-	-
Coincident Peak	S	Other Public Authorities	2,543	2,691	2,172	2,298
Coincident Peak	S	Area Lighting	-	-	-	-
Coincident Peak	S	Street Lighting	-	-	-	-

Losses:

Secondary	
Distribution to	
Transmission	0.058152
Primary	
Distribution to	
Transmission	0.054461

Production			2016		2018 TY	
			12/15/2016 9:00		12/15/2018 9:00	
System Peak Date/Time:						
Load Research Group			Actual	Actual + Losses	Actual	Actual + Losses
Coincident Peak	S	Residential	69,423	77,160	65,706	73,029
Coincident Peak	S	Residential Demand Control	22,843	25,389	18,799	20,894
Coincident Peak	S	Water Controlled Service - Heating	2,363	2,626	2,657	2,953
Coincident Peak	S	Farm	6,414	7,129	9,309	10,346
Coincident Peak	S	General Service - under 20 kW	19,002	21,120	17,153	19,065
Coincident Peak	S	General Service - over 20 kW	64,985	72,228	65,472	72,769
Coincident Peak	P	Large General Service - Primary	23,051	25,531	22,056	24,429
Coincident Peak	T	Large General Service - Transmission	-	-	-	-
Coincident Peak	S	Large General Service - Secondary	61,231	68,055	64,471	71,656
Coincident Peak	S	Fixed Time of Delivery	520	578	403	448
Coincident Peak	S	Small Dual Fuel	44,222	49,151	37,045	41,174
Coincident Peak	S	Large Dual Fuel	24,038	26,717	17,552	19,508
Coincident Peak	S	Controlled Service - Deferred Load	6,755	7,508	4,893	5,438
Coincident Peak	S	General Service - Time of Use	10	11	14	16
Coincident Peak	S	Irrigation	-	-	-	-
Coincident Peak	S	Other Public Authorities	2,543	2,826	2,172	2,414
Coincident Peak	S	Area Lighting	-	-	-	-
Coincident Peak	S	Street Lighting	-	-	-	-

Losses:

Secondary Distribution to	
Transmission	0.11145
Primary Distribution to	
Transmission	0.107574
Transmission to	
Generation	0.050369

Month	Residential				General Service				Fixed Time of Delivery	Dual Fuel		Deferred Load	Commercial Time of Use	Irrigation	Other Public Authority	Area Lights	Street Lights	
	Residential	Demand Control	Water Heater	Farm	Under 20 kW	Over 20 kW	Primary	Transmission		Secondary	Small							Large
January 2016	94,171	24,277	4,679	4,008	18,840	65,270	23,741	250	63,399	16,156	48,898	22,316	7,273	12	-	2,914	2,623	3,033
February 2016	74,137	22,918	4,205	3,364	17,085	59,825	23,824	208	61,361	14,915	49,173	20,064	6,830	15	-	2,780	2,234	3,069
March 2016	65,615	18,661	3,652	2,903	14,310	58,635	22,969	167	61,183	-	39,683	16,960	5,389	15	-	2,732	2,245	2,951
April 2016	61,987	16,043	3,733	2,794	15,639	55,113	23,203	141	60,112	8,571	32,601	14,120	4,045	15	-	2,761	2,231	2,904
May 2016	59,954	10,733	3,630	2,467	16,405	56,640	25,197	169	62,634	4,070	19,371	8,042	2,118	17	477	2,666	2,216	2,875
June 2016	82,185	8,850	2,860	2,773	17,714	53,111	27,063	132	66,175	1,287	8,916	3,238	846	18	1,386	2,950	2,199	2,806
July 2016	89,291	10,024	3,004	2,616	18,652	52,612	27,304	124	71,285	260	9,637	3,418	737	18	914	3,081	2,201	2,791
August 2016	88,306	9,313	3,695	3,524	18,333	53,494	26,304	118	70,622	267	7,179	4,638	675	17	739	2,949	2,206	2,800
September 2016	81,145	7,273	3,389	4,441	17,524	54,651	26,970	125	62,766	739	10,754	4,998	1,098	17	213	2,882	2,220	2,824
October 2016	60,767	12,575	3,944	12,324	14,407	68,984	25,436	118	60,623	4,387	20,440	14,058	2,583	17	221	2,487	2,243	2,862
November 2016	66,260	15,950	3,628	12,271	16,948	67,682	24,765	126	57,133	10,862	29,124	18,406	3,916	15	109	2,777	2,211	2,867
December 2016	93,761	26,642	6,414	7,980	20,325	69,877	24,976	243	62,073	15,874	48,007	25,278	8,051	12	-	3,002	2,234	-
Maximum NCP	94,171	26,642	6,414	12,324	20,325	69,877	27,304	250	71,285	16,156	49,173	25,278	8,051	18	1,386	3,081	2,623	3,069
		120,813																

Source: Company's Response to Data Request ND-PSC 04.28, Attachment 5.

Prepared by: TEM 5/4/2018
Checked by: MD 5/7/2018

	Total	Total Residential	Farm	Total General Service	Total Large General Service	Irrigation	Total Lighting	Other Public Authorities	Water Controlled Service - Heating	Total Controlled Service Interruptible	Total Deferred Load Control
D3 Primary Demand	403477	93145	17305	87448	99596	1424	5902	2877	8160	78771	8849
Additional Demand from MSS adjustment	49432	38349	778	9266	217	29	68	460	29	204	32
Total	452909	131494	18083	96714	99813	1453	5970	3337	8189	78975	8881
	1.000	0.290332561	0.039925675	0.213539704	0.220381052	0.003208258	0.013181579	0.007367524	0.018080993	0.174373055	0.019609599
D4 Secondary Demand	561014	153838	28403	129181	78863	2269	5689	5142	22758	121415	13456
Additional Demand from MSS adjustment	178671	138612	2811	33492	783	105	246	1662	105	738	117
Total	739685	292450	31214	162673	79646	2374	5935	6804	22863	122153	13573
	1	0.395371003	0.042199044	0.219921994	0.107675565	0.003209474	0.008023686	0.00919851	0.030909103	0.165141919	0.018349703
Number of customers	59557	46204	937	11164	261	35	82	554	35	246	39
Primary Demand MSS adjustment (kW)	0.83										
Secondary Demand MSS adjustment (kW)	3.0										

Checked by: MD 5/8/2018

Comparison of Current and Proposed Class Return and RROR

Witness: Dismukes
Case No. PU-17-398
Schedule DED-##

	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Water Heating	Controlled Service Interruptible	Controlled Service Demand
Current										
Return	2.71%	2.07%	7.67%	8.72%	-3.42%	3.01%	1.88%	-0.90%	-1.16%	5.31%
Relative ROR	0.52	0.40	1.47	1.67	(0.66)	0.58	0.36	(0.17)	(0.22)	1.02
Proposed										
Return	5.97%	4.69%	9.94%	11.17%	-1.19%	5.83%	4.87%	1.56%	2.08%	7.75%
Relative ROR	0.75	0.59	1.25	1.40	(0.15)	0.73	0.61	0.20	0.26	0.97

OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2018

LINE NO	ITEM	ALLOCATION	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Water Heating	Controlled Service Interruptible	Controlled Service Deferred
1	RATE BASE		354,191,795	125,874,811	8,479,201	88,428,075	90,600,482	313,267	8,217,318	3,262,553	3,755,746	22,051,030	3,209,311
2													
3	TOTAL AVAILABLE FOR RETURN		18,454,393	3,412,418	175,289	6,783,796	7,904,724	(10,715)	247,020	61,466	(33,919)	(256,217)	170,530
4													
5	RATE OF RETURN EARNED		5.21%	2.71%	2.07%	7.67%	8.72%	-3.42%	3.01%	1.88%	-0.90%	-1.16%	5.31%
6													
7	RATE OF RETURN REQUESTED		7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%
8													
9	OPERATING INCOME REQUIRED		28,229,086	10,032,222	675,792	7,047,718	7,220,858	24,967	654,920	260,026	299,333	1,757,467	255,782
10													
11	TOTAL AVAILABLE FOR RETURN		18,454,393	3,412,418	175,289	6,783,796	7,904,724	(10,715)	247,020	61,466	(33,919)	(256,217)	170,530
12													
13	OPERATING INCOME DEFECIENCY		9,774,693	6,619,804	500,503	263,921	(683,866)	35,683	407,900	198,560	333,252	2,013,684	85,252
14													
15	INCREMENTAL TAXES	GRCF = 1.607756	5,940,627	4,023,224	304,184	160,400	(415,623)	21,686	247,904	120,676	202,536	1,223,828	51,812
16													
17	REVENUE INCREASE REQUIRED		15,715,320	10,643,028	804,687	424,321	(1,099,489)	57,369	655,804	319,236	535,787	3,237,513	137,064
18													
19	PERCENTAGE INCREASE CCROSS		10.61%	22.08%	30.80%	1.09%	-2.55%	97.10%	22.86%	26.51%	49.38%	38.55%	9.00%
20													
21	Present Retail Revenue		\$148,071,951	\$48,209,916	2,612,688	38,950,615	43,160,710	59,083	2,869,144	1,203,986	1,085,033	8,397,154	1,523,622
22	Percentage Increase requested		10.61%	13.70%	13.70%	8.27%	8.26%	19.00%	13.00%	13.00%	13.70%	13.70%	8.26%
23	Revenue increase required		\$15,715,320	\$6,604,758	\$357,938	\$3,221,905	\$3,565,075	\$11,226	\$372,989	\$156,518	\$148,650	\$1,150,410	\$125,851

Class	Proposed Revenue as a Percent of Marginal Costs
Residential	Need to update when available
Farms	
General Service	
Large General Service	
Irrigation	
Lighting	
OPA	
Controlled Service Water Heating	
Controlled Service Interruptible	
Controlled Service Deferred	
Total	

Comparison of Prior Case Class Return and RROR

Witness: Dismukes
Case No. PU-17-398
Schedule DED-##

	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Water Heating	Controlled Service Interruptible	Controlled Service Demand
Case No. PU-08-862 (as Filed)										
Return	3.51%	2.51%	12.23%	12.09%	-3.21%	-0.59%	-0.01%	-2.27%	-9.54%	1.34%
Relative ROR	0.51	0.36	1.77	1.75	-0.46	-0.09	0.00	-0.33	-1.38	0.19
Case No. PU-08-862 (Approved)										
Return	4.85%	3.50%	12.90%	12.09%	-2.02%	3.50%	3.33%	-0.84%	-3.84%	3.75%
Relative ROR	0.60	0.43	1.60	1.50	(0.25)	0.43	0.41	(0.10)	(0.48)	0.46
Case No. PU-17-398										
Return	2.71%	2.07%	7.67%	8.72%	-3.42%	3.01%	1.88%	-0.90%	-1.16%	5.31%
Relative ROR	0.52	0.40	1.47	1.67	(0.66)	0.58	0.36	(0.17)	(0.22)	1.02

OTTER TAIL POWER COMPANY
CLASS COST OF SERVICE STUDY
TEST YEAR - 2018

LINE NO	ITEM	ALLOCATION	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Water Heating	Controlled Service Interruptible	Controlled Service Deferred
1	RATE BASE		354,191,795	125,874,811	8,479,201	88,428,075	90,600,482	313,267	8,217,318	3,262,553	3,755,746	22,051,030	3,209,311
2													
3	TOTAL AVAILABLE FOR RETURN		18,454,393	3,412,418	175,289	6,783,796	7,904,724	(10,715)	247,020	61,466	(33,919)	(256,217)	170,530
4													
5	RATE OF RETURN EARNED		5.21%	2.71%	2.07%	7.67%	8.72%	-3.42%	3.01%	1.88%	-0.90%	-1.16%	5.31%
6													
7	RATE OF RETURN REQUESTED		7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%	7.97%
8													
9	OPERATING INCOME REQUIRED		28,229,086	10,032,222	675,792	7,047,718	7,220,858	24,967	654,920	260,026	299,333	1,757,467	255,782
10													
11	TOTAL AVAILABLE FOR RETURN		18,454,393	3,412,418	175,289	6,783,796	7,904,724	(10,715)	247,020	61,466	(33,919)	(256,217)	170,530
12													
13	OPERATING INCOME DEFECIENCY		9,774,693	6,619,804	500,503	263,921	(683,866)	35,683	407,900	198,560	333,252	2,013,684	85,252
14													
15	INCREMENTAL TAXES	GRCF = 1.607756	5,940,627	4,023,224	304,184	160,400	(415,623)	21,686	247,904	120,676	202,536	1,223,828	51,812
16													
17	REVENUE INCREASE REQUIRED		15,715,320	10,643,028	804,687	424,321	(1,099,489)	57,369	655,804	319,236	535,787	3,237,513	137,064
18													
19	PERCENTAGE INCREASE CCROSS		10.61%	22.08%	30.80%	1.09%	-2.55%	97.10%	22.86%	26.51%	49.38%	38.55%	9.00%
20													
21	Present Retail Revenue		\$148,071,951	\$48,209,916	2,612,688	38,950,615	43,160,710	59,083	2,869,144	1,203,986	1,085,033	8,397,154	1,523,622
22	Percentage Increase requested		10.61%	13.70%	13.70%	8.27%	8.26%	19.00%	13.00%	13.00%	13.70%	13.70%	8.26%
23	Revenue increase required		\$15,715,320	\$6,604,758	\$357,938	\$3,221,905	\$3,565,075	\$11,226	\$372,989	\$156,518	\$148,650	\$1,150,410	\$125,851

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule Residential							
Residential Monthly Customer Charge	\$ 8.00	\$ 8.52	\$15.23	\$15.23	78.8%	\$ 8.85	3.9%
Seasonal Fixed Charge							
Summer	\$ 32.00	\$ 34.08	\$60.92	\$60.92	78.8%	\$ 35.40	3.9%
Winter	\$ 32.00	\$ 34.08	\$60.92	\$60.92	78.8%	\$ 35.40	3.9%
Kilowatt-hour charge							
Energy Tier 1							
Summer	\$ 0.08444	\$ 0.09704	\$ 0.08155	\$ 0.10831	11.6%	\$ 0.10833	11.6%
Winter	\$ 0.07863	\$ 0.09085	\$ 0.06255	\$ 0.08931	-1.7%	\$ 0.10088	11.0%
Energy Tier 2							
Summer	\$ 0.08444	\$ 0.09704	N/A	N/A	N/A	\$ 0.10833	11.6%
Winter	\$ 0.07173	\$ 0.08351	N/A	N/A	N/A	\$ 0.09202	10.2%
Schedule Residential Demand Control							
Residential Monthly Customer Charge	\$ 18.38	\$ 19.57	\$ 20.10	\$20.10	2.7%	\$ 20.10	2.7%
Kilowatt-hour charge							
Summer	\$ 0.04627	\$ 0.05639	\$ 0.04912	\$ 0.07588	34.6%	\$ 0.06308	11.9%
Winter	\$ 0.04671	\$ 0.05686	\$ 0.03812	\$ 0.06488	14.1%	\$ 0.06368	12.0%
Demand per kW							
Summer	\$ 6.52	\$ 6.94	\$ 8.00	\$8.00	15.2%	\$ 7.31	5.3%
Winter	\$ 2.63	\$ 2.80	\$ 8.00	\$8.00	185.6%	\$ 2.95	5.3%

Renewable Resource Adjustment
6.49%

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule Farm Service							
Monthly Customer Charge	\$ 12.00	\$ 12.78	\$ 17.40	\$ 17.40	36.2%	\$ 13.27	3.8%
Facilities Charge							
Single Phase Facilities Charge	\$ -		\$ 10.00	\$ 10.00		\$ -	
All Three Phase Facilities			\$ 20.00	\$ 20.00			
Overhead <= 25kVa	\$ 3.37	\$ 3.59	N/A	N/A		\$ 3.37	-6.1%
Overhead > 25kVa	\$ 3.93	\$ 4.19	N/A	N/A		\$ 3.93	
Underground <= 25kVa	\$ 9.39	\$ 10.00	N/A	N/A		\$ 9.39	
Underground > 25kVa	\$ 10.78	\$ 11.48	N/A	N/A		\$ 10.78	
Kilowatt-hour charge							
First 1600 kWh							
Summer	\$ 0.07642	\$ 0.09171	\$ 0.07000	\$ 0.09799	6.8%	\$ 0.10691	16.6%
Winter	\$ 0.06971	\$ 0.08457	\$ 0.05100	\$ 0.07899	-6.6%	\$ 0.09753	15.3%
Excess kWh							
Summer	\$ 0.06495	\$ 0.07950	N/A	N/A		\$ 0.09087	14.3%
Winter	\$ 0.05925	\$ 0.07343	N/A	N/A		\$ 0.08289	12.9%
Schedule Small General Service - Under 20 kW							
Metered Service Secondary							
Monthly Customer Charge	\$ 13.00	\$ 13.84	\$ 24.90	\$ 24.90	79.9%	\$ 14.38	3.9%
Kilowatt-hour charge							
Summer	\$ 0.08509	\$ 0.09756	\$ 0.07371	\$ 0.10041	2.9%	\$ 0.10938	12.1%
Winter	\$ 0.07762	\$ 0.08960	\$ 0.05471	\$ 0.08141	-9.1%	\$ 0.09977	11.3%
Schedule Small General Service - Under 20 kW							
Metered Service Primary							
Monthly Customer Charge	\$ 13.00	\$ 13.84	\$ 24.90	\$ 24.90	79.9%	\$ 14.38	3.9%
Kilowatt-hour charge							
Summer	\$ 0.08471	\$ 0.09715	\$ 0.07103	\$ 0.09773	0.6%	\$ 0.10959	12.8%
Winter	\$ 0.07725	\$ 0.08921	\$ 0.05203	\$ 0.07873	-11.7%	\$ 0.09994	12.0%

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule General Service - 20 kW or Greater							
Secondary Service							
Monthly Customer Charge	\$ 12.00	\$ 12.78	\$ 31.90	\$ 31.90	149.6%	\$ 13.27	3.8%
Facilities Charge	\$ 0.52	\$ 0.55	\$ 0.98	\$ 0.98	77.0%	\$ 0.52	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.08213	\$ 0.09440	\$ 0.07268	\$ 0.09938	5.3%	\$ 0.10540	11.6%
Winter	\$ 0.07492	\$ 0.08673	\$ 0.06168	\$ 0.08838	1.9%	\$ 0.09615	10.9%
Schedule General Service - 20 kW or Greater							
Primary Service							
Monthly Customer Charge	\$ 12.00	\$ 12.78	\$ 21.30	\$ 21.30	66.7%	\$ 13.27	3.8%
Facilities Charge	\$ 0.38	\$ 0.40	\$ 0.65	\$ 0.65	60.6%	\$ 0.38	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.08176	\$ 0.09401	\$ 0.07005	\$ 0.09675	2.9%	\$ 0.10439	11.0%
Winter	\$ 0.07456	\$ 0.08634	\$ 0.05905	\$ 0.08575	-0.7%	\$ 0.09520	10.3%
Schedule General Service - Time of Use							
(Commercial TOU)							
Monthly Customer Charge	\$ 16.00	\$ 17.04	\$ 219.00	\$ 219.00	1185.3%	\$ 17.70	3.9%
Facilities Charge	\$ 0.52	\$ 0.55	\$ 0.98	\$ 0.98	77.0%	\$ 0.52	-6.1%
Demand per kW							
Declared- Peak	N/A		N/A			N/A	
Intermediate							
Summer	\$ 2.51	\$ 2.67	\$ 3.44	\$ 3.44	28.7%	\$ 2.82	5.5%
Winter	\$ 2.90	\$ 3.09	\$ 5.12	\$ 5.12	65.8%	\$ 3.26	5.6%
Off-Peak	\$ -	\$ -	\$ -	\$ -		\$ -	
Kilowatt-hour charge							
Energy - Declared-Peak							
Summer	\$ 0.20663	\$ 0.22699	\$ 0.48071	\$ 0.50741	123.5%	\$ 0.27200	19.8%
Winter	\$ 0.13679	\$ 0.15261	\$ 0.18066	\$ 0.20736	35.9%	\$ 0.18006	18.0%
Energy - Intermediate							
Summer	\$ 0.07004	\$ 0.08153	\$ 0.03294	\$ 0.05964	-26.8%	\$ 0.09220	13.1%
Winter	\$ 0.07098	\$ 0.08253	\$ 0.03379	\$ 0.06049	-26.7%	\$ 0.09343	13.2%
Energy - Off-Peak							
Summer	\$ 0.04149	\$ 0.05113	\$ 0.02180	\$ 0.04850	-5.1%	\$ 0.05462	6.8%
Winter	\$ 0.04295	\$ 0.05268	\$ 0.02363	\$ 0.05033	-4.5%	\$ 0.05654	7.3%

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule Large General Service- Secondary Service							
Monthly Customer Charge	\$ 40.00	\$ 42.60	\$ 215.90	\$ 215.90	406.8%	\$ 44.25	3.9%
Facilities Charge < 1,000 kW	\$ 0.30	\$ 0.32	\$ 0.76	\$ 0.76	137.9%	\$ 0.30	-6.1%
Facilities Charge >= 1,000 kW	\$ 0.15	\$ 0.16	\$ 0.56	\$ 0.56	250.6%	\$ 0.15	-6.1%
Demand per kW							
Summer	\$ 7.29	\$ 7.76	\$ 11.30	\$ 11.30	45.6%	\$ 8.16	5.1%
Winter	\$ 5.61	\$ 5.97	\$ 8.33	\$ 8.33	39.4%	\$ 6.28	5.1%
Kilowatt-hour charge							
First 700,000 kWh (changing to All kWh)							
Summer	\$ 0.05115	\$ 0.06002	\$ 0.02907	\$ 0.05513	-8.2%	\$ 0.06722	12.0%
Winter	\$ 0.05165	\$ 0.06056	\$ 0.02977	\$ 0.05583	-7.8%	\$ 0.06788	12.1%
Excess kWh							
Summer	\$ 0.04715	\$ 0.05576	N/A	N/A		\$ 0.06197	11.1%
Winter	\$ 0.04761	\$ 0.05625	N/A	N/A		\$ 0.06257	11.2%
Schedule Large General Service- Primary Service							
Monthly Customer Charge	\$ 40.00	\$ 42.60	\$ 282.00	\$ 282.00	562.0%	\$ 44.25	3.9%
Facilities Charge	\$ 0.11	\$ 0.12	\$ 0.48	\$ 0.48	309.8%	\$ 0.11	-6.1%

Demand per kW												
Summer	\$	7.24	\$	7.71	\$	11.06	\$	11.06	43.5%	\$	8.10	5.0%
Winter	\$	5.57	\$	5.93	\$	8.27	\$	8.27	39.4%	\$	6.23	5.0%
Kilowatt-hour charge												
First 700,000 kWh (changing to All kWh)												
Summer	\$	0.05095	\$	0.05981	\$	0.02896	\$	0.05502	-8.0%	\$	0.06723	12.4%
Winter	\$	0.05141	\$	0.06030	\$	0.02947	\$	0.05553	-7.9%	\$	0.06784	12.5%
Excess kWh												
Summer	\$	0.04695	\$	0.05555		N/A				\$	0.06195	11.5%
Winter	\$	0.04737	\$	0.05600		N/A				\$	0.06251	11.6%
Schedule Real Time Pricing- Primary Service												
Monthly Customer Charge	\$	199.00	\$	211.92	\$	282.00	\$	282.00	33.1%	\$	220.13	3.9%

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule Large General Service Time of Day							
Secondary Service							
Monthly Customer Charge	\$ 60.00	\$ 63.90	\$ 215.90	\$215.90	237.9%	\$ 66.37	3.9%
Facilities Charge < 1,000 kW	\$ 0.30	\$ 0.32	\$ 0.76	\$0.76	137.9%	\$ 0.30	-6.1%
Facilities Charge >= 1,000 kW	\$ 0.15	\$ 0.16	\$ 0.57	\$0.57	256.8%	\$ 0.15	-6.1%
Demand per kW							
On-Peak							
Summer	\$ 5.75	\$ 6.12	\$ 7.86	\$ 7.86	28.4%	\$ 6.46	5.5%
Winter	\$ 4.42	\$ 4.71	\$ 5.13	\$ 5.13	9.0%	\$ 4.97	5.5%
Shoulder							
Summer	\$ 1.59	\$ 1.69	\$ 3.44	\$ 3.44	103.2%	\$ 1.79	5.5%
Winter	\$ 1.22	\$ 1.30	\$ 3.20	\$ 3.20	146.3%	\$ 1.37	5.5%
Kilowatt-hour charge							
Energy - On-Peak							
Summer	\$ 0.08150	\$ 0.09234	\$ 0.04485	\$ 0.07091	-23.2%	\$ 0.10714	16.0%
Winter	\$ 0.07314	\$ 0.08344	\$ 0.03929	\$ 0.06535	-21.7%	\$ 0.09615	15.2%
Energy - Shoulder							
Summer	\$ 0.06247	\$ 0.07208	\$ 0.03412	\$ 0.06018	-16.5%	\$ 0.08213	13.9%
Winter	\$ 0.05949	\$ 0.06890	\$ 0.03500	\$ 0.06106	-11.4%	\$ 0.07821	13.5%
Energy - Off-Peak							
Summer	\$ 0.03721	\$ 0.04518	\$ 0.02258	\$ 0.04864	7.7%	\$ 0.04892	8.3%
Winter	\$ 0.04199	\$ 0.05027	\$ 0.02448	\$ 0.05054	0.5%	\$ 0.05520	9.8%

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Standby Service - Option A: Firm							
Transmission Service							
Monthly Customer Charge	\$ 199.00	\$ 199.00	\$ 304.33	\$304.33	52.9%	\$ 220.13	10.6%
Reservation Charge per kW of Contracted Backup							
Summer	\$ 0.81704	\$ 0.81704	\$ 0.58422	\$ 0.58422	-28.5%	\$ 0.92665	13.4%
Winter	\$ 0.09254	\$ 0.09254	\$ 0.19898	\$ 0.19898	115.0%	\$ 0.10495	13.4%
Metered Demand per day per kW On-Peak Backup							
Summer	\$ 0.35865	\$ 0.35865	\$ 0.48812	\$ 0.48812	36.1%	\$ 0.40676	13.4%
Winter	\$ 0.28694	\$ 0.28694	\$ 0.37420	\$ 0.37420	30.4%	\$ 0.32543	13.4%
Kilowatt-hour charge							
Energy - On-Peak							
Summer	\$ 0.07900	\$ 0.07900	\$ 0.04184	\$ 0.04184	-47.0%	\$ 0.07938	0.5%
Winter	\$ 0.07063	\$ 0.07063	\$ 0.03613	\$ 0.03613	-48.8%	\$ 0.08920	26.3%
Energy - Shoulder							
Summer	\$ 0.06066	\$ 0.06066	\$ 0.03210	\$ 0.03210	-47.1%	\$ 0.06464	6.6%
Winter	\$ 0.05752	\$ 0.05752	\$ 0.03247	\$ 0.03247	-43.6%	\$ 0.07265	26.3%
Energy - Off-Peak							
Summer	\$ 0.03635	\$ 0.03635	\$ 0.02140	\$ 0.02140	-41.1%	\$ 0.04574	25.8%
Winter	\$ 0.04070	\$ 0.04070	\$ 0.02292	\$ 0.02292	-43.7%	\$ 0.05140	26.3%

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Schedule Irrigation Service - Option 1							
Non-Time-of-Use							
Monthly Customer Charge	\$ 1.00	\$ 1.06	\$ 24.30	\$24.30	2181.9%	\$ 1.11	3.9%
Kilowatt-hour charge							
Summer	\$ 0.06896	\$ 0.07311	\$ 0.05552	\$ 0.07835	7.2%	\$ 0.08629	18.0%
Winter	\$ 0.05145	\$ 0.05446	\$ 0.03652	\$ 0.05935	9.0%	\$ 0.06438	18.2%
Schedule Irrigation Service - Option 2							
Monthly Customer Charge	\$ 5.00	\$ 5.32	\$ 24.30	\$24.30	356.4%	\$ 5.53094	3.9%
Kilowatt-hour charge							
Energy - Declared-Peak							
Summer	\$ 0.14450	\$ 0.15355	\$ 0.17685	\$ 0.19968	30.0%	\$ 0.18005	17.3%
Winter	\$ 0.08760	\$ 0.09296	\$ 0.14297	\$ 0.16580	78.4%	\$ 0.10915	17.4%
Energy - Intermediate							
Summer	\$ 0.05441	\$ 0.05762	\$ 0.04155	\$ 0.06438	11.7%	\$ 0.06780	17.7%
Winter	\$ 0.05111	\$ 0.05410	\$ 0.04217	\$ 0.06500	20.1%	\$ 0.06369	17.7%
Energy - Off-Peak							
Summer	\$ 0.02642	\$ 0.02781	\$ 0.01802	\$ 0.04085	46.9%	\$ 0.03292	18.4%
Winter	\$ 0.02612	\$ 0.02749	\$ 0.02015	\$ 0.04298	56.3%	\$ 0.03255	18.4%

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Outdoor Lighting - Metered - Energy Only							
Monthly Customer Charge	\$ 2.00	\$ 2.13	\$ 2.00	\$ 2.00	-6.1%	\$ 2.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.06978	\$ 0.07876	\$ 0.07047	\$ 0.09625	22.2%	\$ 0.08977	14.0%
Winter	\$ 0.06978	\$ 0.07876	\$ 0.07047	\$ 0.09625	22.2%	\$ 0.08977	14.0%
Outdoor Lighting - Non-Metered - Energy Only							
Monthly Charge for Connected Kw	\$ 23.84	\$ 25.39	\$ 24.08	\$ 24.08	-5.2%	\$ 30.39	19.7%
Sign Lighting							
Monthly Charge for Connected Kw	\$ 23.84	\$ 25.39	\$ 24.08	\$ 24.08	-5.2%	\$ 30.45	19.9%
Outdoor Lighting - Street & Area Lighting							
MV-6	\$ 7.01	\$ 7.47	\$ 7.12	\$ 7.12	-4.6%	\$ 8.74	17.0%
MV-6PT	\$ 10.00	\$ 10.65	\$ 10.16	\$ 10.16	-4.6%	\$ 12.46	17.0%
MV-11	\$ 12.70	\$ 13.52	\$ 12.90	\$ 12.90	-4.6%	\$ 15.83	17.0%
MV-21	\$ 16.72	\$ 17.81	\$ 16.99	\$ 16.99	-4.6%	\$ 20.84	17.0%
MV-35	\$ 24.53	\$ 26.12	\$ 24.92	\$ 24.92	-4.6%	\$ 30.57	17.0%
MV-55	\$ 31.36	\$ 33.40	\$ 31.96	\$ 31.96	-4.6%	\$ 38.08	17.0%
MA-8	\$ 8.46	\$ 9.01	\$ 8.59	\$ 8.59	-4.6%	\$ 10.54	17.0%
MA-14	\$ 16.10	\$ 17.15	\$ 16.36	\$ 16.36	-4.6%	\$ 20.06	17.0%
MA-20	\$ 18.38	\$ 19.57	\$ 18.67	\$ 18.67	-4.6%	\$ 22.90	17.0%
MA-36	\$ 18.00	\$ 19.17	\$ 18.29	\$ 18.29	-4.6%	\$ 22.43	17.0%
MA-110	\$ 38.41	\$ 40.90	\$ 39.02	\$ 39.02	-4.6%	\$ 47.86	17.0%
HPS-9	\$ 7.52	\$ 8.01	\$ 7.64	\$ 7.64	-4.6%	\$ 9.37	17.0%
HPS-9PT	\$ 9.72	\$ 10.35	\$ 9.87	\$ 9.87	-4.6%	\$ 12.11	17.0%
HPS-14	\$ 11.71	\$ 12.47	\$ 11.90	\$ 11.90	-4.6%	\$ 14.59	17.0%
HPS-14PT	\$ 12.53	\$ 13.34	\$ 12.73	\$ 12.73	-4.6%	\$ 15.61	17.0%
HPS-19	\$ 13.61	\$ 14.49	\$ 13.83	\$ 13.83	-4.6%	\$ 16.96	17.0%
HPS-23	\$ 15.40	\$ 16.40	\$ 15.65	\$ 15.65	-4.6%	\$ 19.19	17.0%
HPS-44	\$ 19.01	\$ 20.24	\$ 19.31	\$ 19.31	-4.6%	\$ 23.69	17.0%
UHP523	\$ 17.99	\$ 19.16	\$ 18.11	\$ 18.11	-5.5%	\$ 22.42	17.0%
UHP59	\$ 9.86	\$ 10.50	\$ 10.10	\$ 10.10	-3.8%	\$ 12.29	17.0%
UMV6	\$ 8.97	\$ 9.55	\$ 9.58	\$ 9.58	0.3%	\$ 11.18	17.0%
Seasonal Charge	\$ 10.80	\$ 11.50	\$ 32.79	\$ 32.79	185.1%	\$ 13.46	17.0%
Outdoor Lighting - Flood Lighting							
400MV-F	\$ 17.35	\$ 18.48	\$ 17.63	\$ 17.63	-4.6%	\$ 21.68	17.4%
400MA-F	\$ 18.49	\$ 19.69	\$ 18.78	\$ 18.78	-4.6%	\$ 23.11	17.4%

400HPS-F	\$ 18.90	\$ 20.13	\$ 19.20	\$ 19.20	-4.6%	\$ 23.62	17.4%
1000MV-F	\$ 30.44	\$ 32.42	\$ 30.93	\$ 30.93	-4.6%	\$ 38.04	17.4%
1000MA-F	\$ 32.11	\$ 34.19	\$ 32.62	\$ 32.62	-4.6%	\$ 40.13	17.4%
1M+HPS-F	\$ 37.32	\$ 39.74	\$ 37.91	\$ 37.91	-4.6%	\$ 46.64	17.4%
U1M-MAF	\$ 39.44	\$ 42.00	\$ 21.66	\$ 21.66	-48.4%	\$ 49.29	17.4%
Underground Service	\$ 1.96	\$ 2.09	\$ 2.46	\$ 2.46	17.9%	\$ 2.45	17.4%

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Municipal Pumping - Secondary Service							
Monthly Customer Charge	\$ 4.00	\$ 4.26	\$ 26.50	\$ 26.50	522.1%	\$ 4.42	3.9%
Facilities Charge	\$ 4.00	\$ 4.26	\$ 0.65	\$ 0.65	-84.7%	\$ 4.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.06523	\$ 0.07509	\$ 0.05159	\$ 0.07764	3.4%	\$ 0.08562	14.0%
Winter	\$ 0.05950	\$ 0.06998	\$ 0.03490	\$ 0.06095	-11.7%	\$ 0.07809	13.2%
Civil Defense - Fire Sirens							
Monthly Customer Charge	\$ 1.00	\$ 1.06	\$ 1.22	\$ 1.22	14.6%	\$ 1.10619	3.9%
Load Charge	\$ 0.53193	\$ 0.56646	\$ 0.42962	\$ 0.42962	-24.2%	\$ 0.66459	17.3%
Water Heating - Controlled Service							
Monthly Customer Charge	\$ 1.00	\$ 1.06	\$ 4.00	\$ 4.00	\$ 2.76	\$ 1.11	3.9%
Facilities Charge	\$ 1.00	\$ 1.06	\$ 2.00	\$ 2.00	\$ 0.88	\$ 1.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.05773	\$ 0.06369	\$ 0.03317	\$ 0.05818	-8.6%	\$ 0.07359	15.6%
Winter	\$ 0.05638	\$ 0.06225	\$ 0.02868	\$ 0.05369	-13.7%	\$ 0.07187	15.5%

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Controlled Service - Interruptible Load Rider CT Metering - Option 1							
Monthly Customer Charge	\$ 4.00	\$ 4.26	\$ 20.20	\$ 20.20	374.2%	\$ 4.42	3.9%
Facilities Charge	\$ 0.08	\$ 0.09	\$ 0.76	\$ 0.76	792.1%	\$ 0.08	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.03166	\$ 0.03690	\$ 0.01060	\$ 0.03633	-1.6%	\$ 0.04213	14.2%
Winter	\$ 0.03044	\$ 0.03561	\$ 0.01005	\$ 0.03578	0.5%	\$ 0.04050	13.8%
Penalty Kilowatt-hour charge							
Summer	\$ 0.39448	\$ 0.42328	\$ 0.41350	\$ 0.43923	3.8%	\$ 0.41350	-2.3%
Winter	\$ 0.12726	\$ 0.13871	\$ 0.14322	\$ 0.16895	21.8%	\$ 0.14322	3.3%
Controlled Service - Interruptible Load Rider CT Metering - Option 2							
Monthly Customer Charge	\$ 5.00	\$ 5.32	\$ 20.20	\$ 20.20	279.4%	\$ 5.53	3.9%
Facilities Charge	\$ 0.08	\$ 0.09	\$ 0.76	\$ 0.76	792.1%	\$ 0.08	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.03336	\$ 0.03871	\$ 0.01060	\$ 0.03633	-6.2%	\$ 0.04435	14.5%
Winter	\$ 0.03208	\$ 0.03735	\$ 0.01005	\$ 0.03578	-4.2%	\$ 0.04264	14.2%
Control Period Demand							
Summer	\$ 7.29	\$ 7.76	\$ 11.38	\$ 11.38	46.6%	\$ 8.44	8.7%
Winter	\$ 5.61	\$ 5.97	\$ 6.25	\$ 6.25	4.6%	\$ 6.49	8.7%
Controlled Service - Interruptible Load Rider Self-Contained Metering							
Monthly Customer Charge	\$ 2.00	\$ 2.13	\$ 8.50	\$ 8.50	299.1%	\$ 2.21	3.9%
Facilities Charge	\$ 5.00	\$ 5.32	\$ 11.70	\$ 11.70	119.7%	\$ 5.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.03659	\$ 0.04215	\$ 0.01111	\$ 0.03683	-12.6%	\$ 0.04888	16.0%
Winter	\$ 0.03451	\$ 0.03994	\$ 0.01037	\$ 0.03609	-9.6%	\$ 0.04610	15.4%
Penalty Kilowatt-hour charge							
Summer	\$ 0.38606	\$ 0.41431	\$ 0.41350	\$ 0.43922	6.0%	\$ 0.41350	-0.2%
Winter	\$ 0.12924	\$ 0.14082	\$ 0.16537	\$ 0.19110	35.7%	\$ 0.16537	17.4%

Description	Company's Present Rate	With Riders	Company's Proposed Rate	With Riders	Increase from Present Rate	Alternative Rates	Increase from Present Rate
Controlled Service - Deferred Load Rider							
Monthly Customer Charge	\$ 3.00	\$ 3.19	\$ 8.80	\$ 8.80	175.5%	\$ 3.32	3.9%
Facilities Charge	\$ 4.00	\$ 4.26	\$ 11.60	\$ 11.60	172.3%	\$ 4.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.05154	\$ 0.05831	\$ 0.02762	\$ 0.05355	-8.2%	\$ 0.06659	14.2%
Winter	\$ 0.05002	\$ 0.05669	\$ 0.02516	\$ 0.05110	-9.9%	\$ 0.06463	14.0%
Penalty Kilowatt-hour charge							
Summer	\$ 0.33802	\$ 0.36338	\$ 0.35916	\$ 0.38510	6.0%	\$ 0.35916	-1.2%
Winter	\$ 0.11510	\$ 0.12599	\$ 0.16537	\$ 0.19131	51.8%	\$ 0.16537	31.3%
Fixed Time of Service Rider - Self-Contained Metering							
Monthly Customer Charge	\$ 1.00	\$ 1.06	\$ 6.70	\$ 6.70	529.2%	\$ 1.11	3.9%
Facilities Charge	\$ 3.00	\$ 3.19	\$ 6.00	\$ 6.00	87.8%	\$ 3.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.01626	\$ 0.02074	\$ 0.01525	\$ 0.04118	98.6%	\$ 0.03859	86.1%
Winter	\$ 0.03325	\$ 0.03883	\$ 0.01687	\$ 0.04280	10.2%	\$ 0.04085	5.2%
Penalty Kilowatt-hour charge							
Summer	\$ 0.05676	\$ 0.06044	\$ 0.06736	\$ 0.09330	54.3%	\$ 0.06736	11.4%
Winter	\$ 0.03605	\$ 0.03839	\$ 0.04602	\$ 0.07196	87.4%	\$ 0.04602	19.9%
Fixed Time of Service Rider - CT Metering							
Monthly Customer Charge	\$ 1.50	\$ 1.60	\$ 6.70	\$ 6.70	319.4%	\$ 1.66	3.9%
Facilities Charge	\$ 19.00	\$ 20.23	\$ 38.00	\$ 38.00	87.8%	\$ 19.00	-6.1%
Kilowatt-hour charge							
Summer	\$ 0.01626	\$ 0.02074	\$ 0.01525	\$ 0.04118	98.6%	\$ 0.03810	83.7%
Winter	\$ 0.03325	\$ 0.03883	\$ 0.01687	\$ 0.04280	10.2%	\$ 0.04034	3.9%
Penalty Kilowatt-hour charge							
Summer	\$ 0.05676	\$ 0.06387	\$ 0.06736	\$ 0.09330	46.1%	\$ 0.06736	5.5%
Winter	\$ 0.03605	\$ 0.04181	\$ 0.04602	\$ 0.07196	72.1%	\$ 0.04602	10.1%

Note: Present and proposed rates are taken from supplemental and direct testimonies of David G. Prazak in instances where they do not match Company's workpapers.
Source: Direct Testimony of David G. Prazak, Table 6 - Table 20; Supplemental Direct Testimony of David G. Prazak, Schedule 2; and Alternative Schedule E-2.

Prepared by: TEM 4/2/2018 and 5/16/2018
Checked by: SB 5/16/2018
Edited by: TEM 5/16/2018 & GO 5/16/2018
Updated by: GO 5/17/2018

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter				
1	9.01 Residential Service (Rate 101)												
2	Customer Charge	Bills			526,602	\$8.00	\$8.00	\$ 17.70	\$ 17.70	\$ 4,212,722	\$ 9,320,860	\$ 5,108,138	
3	Seasonal Fixed Charge	Bills			6	\$32.00	\$32.00	\$70.80	\$70.80	\$ 415	\$ 434	\$ 19	
4	Energy Tier 1	kWh	105,061,675	208,279,694	313,341,369	\$0.08444	\$0.07863	\$0.07851	\$0.05951	\$ 25,248,440	\$ 26,759,641	\$ (5,676,389)	
5	Energy Tier 2	kWh	18,332,063	78,623,028	96,955,091	\$0.08444	\$0.07173	N/A	N/A	\$ 7,187,589			
6	Water Heating Control Credit 14.01 (Rate 192)	Bills			2,247	-\$4.00	-\$4.00	-\$8.00	-\$8.00	\$ (8,988)	\$ (17,976)	\$ (8,988)	
7	Air Conditioning Control Rider 14.08 (Rate 760)	Bills			1,257	-\$7.00	-\$7.00	-\$8.25	-\$8.25	\$ (8,799)	\$ (10,370)	\$ (1,571)	
8	TailWinds Program 14.09	kWh			3,448	\$1.30	\$1.30	\$3.73	\$3.73	\$ 4,482	\$ 12,672	\$ 8,190	
9	WAPA Bill Credit 14.10									\$ (34,852)	\$ (34,852)	\$ -	
10	Total Base Revenue:									\$ 36,601,009	\$ 36,030,409	\$ (570,601)	
11	Adjustments for Riders included in Base Rates					Present	Proposed						
12	Economic Development Adjustment	kWh			410,296,460	-\$0.00030	\$0.00000			\$ (122,350)	\$ -		
13	Environmental Cost Recovery Rider Adjustment	\$			\$36,601,009.21	6.49%	0.00%			\$ 2,376,043	\$ -		
14	Renewable Resource Adjustment	kWh			410,296,460	\$0.00511	\$0.00000			\$ 2,096,228	\$ -		
15	Transmission Rider Adjustment	kWh			410,296,460	\$0.00552	\$0.00194			\$ 2,263,447	\$ 796,927		
16	COE Adjustment	kWh			410,296,460	-\$0.00321	\$0.02482			\$ (1,316,326)	\$ 10,184,284		
17	Total Adjustments:									\$ 5,297,042	\$ 10,981,211	\$ 5,684,169	
18													
19	9.02 Residential Demand Control (Rate 241)												
20	Customer Charge	Bills			41,515	\$18.38	\$18.38	\$20.10	\$20.10	\$ 763,051	\$ 834,457	\$ 71,406	
21	Facilities Charge	Bills			41,515	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
22	Energy - All kWh	kWh	15,859,624	68,238,179	84,097,803	\$0.04627	\$0.04671	\$0.04852	\$0.03752	\$ 3,921,230	\$ 3,329,533	\$ (591,697)	
23	All kW	kW	57,636	115,897	173,533	\$6.52	\$2.63	\$8.00	\$8.00	\$ 680,598	\$ 1,388,264	\$ 707,666	
24	Total Base Revenue:									\$ 5,364,879	\$ 5,552,254	\$ 187,375	
25	Adjustments for Riders included in Base Rates					Present	Proposed						
26	Economic Development Adjustment	kWh			84,097,803	-\$0.00030	\$0.00000			\$ (25,078)	\$ -		
27	Environmental Cost Recovery Rider Adjustment	\$			\$5,364,879.17	6.49%	0.00%			\$ 348,274	\$ -		
28	Renewable Resource Adjustment	kWh			84,097,803	\$0.00511	\$0.00000			\$ 429,661	\$ -		
29	Transmission Rider Adjustment	kWh			84,097,803	\$0.00552	\$0.00194			\$ 463,935	\$ 163,345		
30	COE Adjustment	kWh			84,097,803	-\$0.00321	\$0.02482			\$ (269,805)	\$ 2,087,456		
31	Total Adjustments:									\$ 946,987	\$ 2,250,801	\$ 1,303,814	
32													
33	Total Base Revenue for the COSS Class:									\$ 41,965,888	\$ 41,582,663	\$ (383,226)	
34	Total Adjustments for the COSS Class:									\$ 6,244,028	\$ 13,232,012	\$ 6,987,983	
35	Total for the COSS Class:									\$ 48,209,916	\$ 54,814,675	\$ 6,604,758	13.70%
36													
37	9.03 Farm Service (Rate 361)												
38	Customer Charge	Bills			13,378	\$12.00	\$12.00	\$17.40	\$17.40	\$ 160,541	\$ 232,784	\$ 72,243	
39	Energy - First 1600 kWh	kWh	3,269,529	6,977,834	10,247,363	\$0.07642	\$0.06971	\$0.07000	\$0.05100	\$ 736,282	\$ 1,707,544	\$ (265,638)	
40	Energy - Excess kWh	kWh	4,115,927	16,364,057	20,479,984	\$0.06495	\$0.05925			\$ 1,236,900	\$ -	\$ (1,236,900)	
41	Single Phase Facilities Charge	Bills			9,720	\$0.00	\$0.00	\$10.00	\$10.00	\$ -	\$ 97,203	\$ 97,203	
42	All Three Phase Facilities	Bills			3,658			\$20.00	\$20.00	\$ 21,705	\$ 73,161	\$ 51,456	
43	Overhead =< 25kVa	Bills			1,731	\$3.37	\$3.37						
44	Overhead > 25kVa	Bills			488	\$3.93	\$3.93						
45	Underground <= 25kVa	Bills			1,220	\$9.39	\$9.39						
46	Underground > 25kVa	Bills			218	\$10.78	\$10.78						
47	Water Heating Control Credit 14.01 (Rate 192)	Bills			12	-\$4.00	-\$4.00	-\$8.00	-\$8.00	\$ (48)	\$ (96)	\$ (48)	
48	Air Conditioning Control Rider 14.08 (Rate 760)	Bills			11	-\$7.00	-\$7.00	-\$8.25	-\$8.25	\$ (77)	\$ (91)	\$ (14)	
49													
50	Total Base Revenue:									\$ 2,155,303	\$ 2,110,506	\$ (44,797)	
51	Adjustments for Riders included in Base Rates					Present	Proposed						
52	Economic Development Adjustment	kWh			30,727,347	-\$0.00025	\$0.00000			\$ (7,572)	\$ -	\$ 7,572	
53	Environmental Cost Recovery Rider Adjustment	%			2,155,303	6.49%	0.00%			\$ 139,920	\$ -	\$ (139,920)	
54	Renewable Resource Adjustment	kWh			30,727,347	\$0.00511	\$0.00000			\$ 156,914	\$ -	\$ (156,914)	
55	Transmission Rider Adjustment	kWh			30,727,347	\$0.00850	\$0.00299			\$ 261,286	\$ 91,995	\$ (169,291)	
56	COE Adjustment	kWh			30,727,347	-\$0.00303	\$0.02500			\$ (93,163)	\$ 768,125		
57	Total Adjustments:									\$ 457,384	\$ 860,120	\$ 402,735	
58													
59	Total Base Revenue for the COSS Class:									\$ 2,155,303	\$ 2,110,506	\$ (44,797)	
60	Total Adjustments for the COSS Class:									\$ 457,384	\$ 860,120	\$ 402,736	
61	Total for the COSS Class:									\$ 2,612,687	\$ 2,970,625	\$ 357,938	13.70%
62													
63													
64	10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)												
65	Customer Charge	Bills			109,530	\$13.00	\$13.00	\$24.90	\$24.90	\$ 1,423,887	\$ 2,727,291	\$ 1,303,404	

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter				
66	Energy	kWh	26,415,240	60,891,902	87,307,142	\$0.08509	\$0.07762	\$0.07371	\$0.05471	\$ 6,974,102	\$ 5,278,153	\$ (1,695,949)	
67	Water Heating Control Credit 14.01 (Rate 192)	Bills			178	-\$4.00	-\$4.00	-\$8.00	-\$8.00	\$ (712)	\$ (1,424)	\$ (712)	
68	WAPA Bill Credit 14.10				-	\$0.00	\$0.00	\$0.00	\$0.00	\$ (22,280)	\$ (22,248)	\$ 32	
69	TailWinds Program 14.09				779	\$1.30	\$1.30	\$3.73	\$3.73	\$ 1,013	\$ 2,908	\$ 1,895	
70													
71	Total Base Revenue:									\$ 8,376,010	\$ 7,984,679	\$ (391,331)	
72	Adjustments for Riders included in Base Rates					Present	Proposed						
73	Economic Development Adjustment	kWh			87,307,142	-\$0.00030	\$0.00000			\$ (25,957)	\$ -	\$ 25,957	
74	Environmental Cost Recovery Rider Adjustment	%			8,376,010	6.49%	0.00%			\$ 543,749	\$ -	\$ (543,749)	
75	Renewable Resource Adjustment	kWh			87,307,142	\$0.00511	\$0.00000			\$ 446,050	\$ -	\$ (446,050)	
76	Transmission Rider Adjustment	kWh			87,307,142	\$0.00534	\$0.00188			\$ 466,218	\$ 164,149	\$ (302,070)	
77	COE Adjustment	kWh			87,307,142	-\$0.00321	\$0.02482			\$ (280,161)	\$ 2,167,058	\$ 2,447,219	
78	Total Adjustments:									\$ 1,149,899	\$ 2,331,207	\$ 1,181,308	
79													
80	10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)												
81	Customer Charge	Bills			8	\$13.00	\$13.00	\$45.63	\$45.63	\$ 106	\$ 203	\$ 97	
82	Seasonal Fixed Charge	Bills	567	4,086	4,653	\$0.08471	\$0.07725	\$0.07103	\$0.05203	\$ 364	\$ 253	\$ (111)	
83	Energy	kWh											
84	Total Base Revenue:									\$ 470	\$ 456	\$ (14)	
85	Adjustments for Riders included in Base Rates					Present	Proposed						
86	Economic Development Adjustment	kWh			4,653	-\$0.00030	\$0.00000			\$ (1)	\$ -	\$ 1	
87	Environmental Cost Recovery Rider Adjustment	%			470	6.49%	0.00%			\$ 30	\$ -	\$ (30)	
88	Renewable Resource Adjustment	kWh			4,653	\$0.00511	\$0.00000			\$ 24	\$ -	\$ (24)	
89	Transmission Rider Adjustment	kWh			4,653	\$0.00534	\$0.00188			\$ 25	\$ 9	\$ (16)	
90	COE Adjustment	kWh			4,653	-\$0.00321	\$0.02482			\$ (15)	\$ 115	\$ 130	
91	Total Adjustments:									\$ 63	\$ 124	\$ 61	
92													
93													
94	10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)												
95	Customer Charge	Bills			35,324	\$12.00	\$12.00	\$31.90	\$31.90	\$ 423,890	\$ 1,126,842	\$ 702,951	
96	Energy	kWh	89,250,972	223,847,637	313,098,609	\$0.08213	\$0.07492	\$0.07268	\$0.06168	\$ 24,100,711	\$ 20,294,726	\$ (3,805,985)	
97	Demand per kW	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
98	Facilities Charge	kW			2,190,307	\$0.52	\$0.52	\$0.98	\$0.98	\$ 1,138,960	\$ 2,140,922	\$ 1,001,962	
99	WAPA Bill Credit 14.10	kWh								\$ (148,217)	\$ (148,217)	\$ -	
100													
101	Total Base Revenue:									\$ 25,515,344	\$ 23,414,272	\$ (2,101,072)	
102	Adjustments for Riders included in Base Rates					Present	Proposed						
103	Economic Development Adjustment	kWh			313,098,609	-\$0.00030	\$0.00000			\$ (93,085)	\$ -	\$ 93,085	
104	Environmental Cost Recovery Rider Adjustment	%			25,515,344	6.49%	0.00%			\$ 1,656,389	\$ -	\$ (1,656,389)	
105	Renewable Resource Adjustment	kWh			313,098,609	\$0.00511	\$0.00000			\$ 1,599,612	\$ -	\$ (1,599,612)	
106	Transmission Rider Adjustment	kWh			313,098,609	\$0.00534	\$0.00188			\$ 1,671,941	\$ 588,666	\$ (1,083,275)	
107	COE Adjustment	kWh			313,098,609	-\$0.00321	\$0.02482			\$ (1,004,706)	\$ 7,771,448	\$ 8,776,154	
108	Total Adjustments:									\$ 3,830,150	\$ 8,360,114	\$ 4,529,964	
109													
110	10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)												
111	Customer Charge	Bills			40	\$12.00	\$12.00	\$21.30	\$21.30	\$ 483	\$ 858	\$ 375	
112	Energy	kWh	244,376	514,386	758,762	\$0.08176	\$0.07456	\$0.07005	\$0.05905	\$ 58,333	\$ 47,491	\$ (10,842)	
113	Demand per kW	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
114	Facilities Charge	kW			2,737	\$0.38	\$0.38	\$0.65	\$0.65	\$ 1,040	\$ 1,793	\$ 752	
115	Total Base Revenue:									\$ 59,856	\$ 50,141	\$ (9,715)	
116	Adjustments for Riders included in Base Rates					Present	Proposed						
117	Economic Development Adjustment	kWh			758,762	-\$0.00030	\$0.00000			\$ (226)	\$ -	\$ 226	
118	Environmental Cost Recovery Rider Adjustment	%			59,856	6.49%	0.00%			\$ 3,886	\$ -	\$ (3,886)	
119	Renewable Resource Adjustment	kWh			758,762	\$0.00511	\$0.00000			\$ 3,876	\$ -	\$ (3,876)	
120	Transmission Rider Adjustment	kWh			758,762	\$0.00534	\$0.00188			\$ 4,052	\$ 1,427	\$ (2,625)	
121	COE Adjustment	kWh			758,762	-\$0.00321	\$0.02482			\$ (2,435)	\$ 18,833	\$ 21,268	
122	Total Adjustments:									\$ 9,154	\$ 20,260	\$ 11,106	
123													
124	10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)												
125	Customer Charge	Bills			12	\$16.00	\$16.00	\$219.00	\$219.00	\$ 192	\$ 2,628	\$ 2,436	
126	Energy - Declared-Peak	kWh	286	321	607	\$0.20663	\$0.13679	\$0.48071	\$0.18066	\$ 270	\$ 195	\$ (74)	
127	Energy - Intermediate	kWh	25,318	41,592	66,910	\$0.07004	\$0.07098	\$0.03294	\$0.03379	\$ 4,683	\$ 2,239	\$ (2,443)	
128	Energy - Off-Peak	kWh	18,078	29,986	48,064	\$0.04149	\$0.04295	\$0.02180	\$0.02363	\$ 2,038	\$ 1,103	\$ (935)	
129	Demand per kW - Declared-Peak	kW	-	-	-	N/A	N/A	N/A	N/A	\$ -	\$ -	\$ -	
130	Demand per kW - Intermediate	kW	88	181	269	\$2.51	\$2.90	\$3.44	\$5.12	\$ 733	\$ 1,229	\$ 497	
131	Demand per kW - Off-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual	
			Summer	Winter	Annual	Summer	Winter	Summer	Winter					
132	Facilities Charge	kW			-	\$0.52	\$0.52	\$0.98	\$0.98	\$ 412	\$ 787	\$ 375		
133												\$ -		
134	Total Base Revenue:										\$ 8,328	\$ 8,182	\$ (146)	
135	Adjustments for Riders included in Base Rates													
136	Economic Development Adjustment	kWh			115,581	-\$0.00030	\$0.00000			\$ (34)	\$ -	\$ 34		
137	Environmental Cost Recovery Rider Adjustment	%			8,328	6.49%	0.00%			\$ 541	\$ -	\$ (541)		
138	Renewable Resource Adjustment	kWh			115,581	\$0.00511	\$0.00000			\$ 590	\$ -	\$ (590)		
139	Transmission Rider Adjustment	kWh			115,581	\$0.00534	\$0.00188			\$ 617	\$ 217	\$ (400)		
140	COE Adjustment	kWh			115,581	-\$0.00321	\$0.02482			\$ (371)	\$ 2,869	\$ 3,240		
141	Total Adjustments:										\$ 1,343	\$ 3,086	\$ 1,743	
142														
143	Total Base Revenue for the COSS Class:										\$ 33,960,007	\$ 31,457,729	\$ (2,502,278)	
144	Total Adjustments for the COSS Class:										\$ 4,990,608	\$ 10,714,791	\$ 5,724,182	
145	Total for the COSS Class:										\$ 38,950,615	\$ 42,172,520	\$ 3,221,905	8.27%
146														
147														
148	10.04 Large General Service - Secondary Service (Rate 603)													
149	Customer Charge	Bills			3,272	\$40.00	\$40.00	\$215.90	\$215.90	\$ 130,873	\$ 706,387	\$ 575,514		
150	Energy - First 700,000 kWh (changing to All kWh)	kWh	96,654,016	190,461,494	287,115,510	\$0.05115	\$0.05165	\$0.03191	\$0.03268	\$ 14,781,189	\$ 13,741,820	\$ (7,530,159.93)		
151	Energy - Excess kWh	kWh	49,275,147	87,533,453	136,808,600	\$0.04715	\$0.04761			\$ 6,490,791	\$ -	\$ -		
152	Demand per kW	kW	322,537	623,784	946,321	\$7.29	\$5.61	\$11.38	\$6.25	\$ 5,850,722	\$ 7,566,084	\$ 1,715,362		
153	Facilities Charge <1,000 kW	kW	212,293	414,007	626,300	\$0.30	\$0.30	\$0.76	\$0.76	\$ 187,890	\$ 473,465	\$ 285,575		
154	Facilities Charge >=1,000 kW	kW	165,998	340,526	506,524	\$0.15	\$0.15	\$0.56	\$0.56	\$ 75,979	\$ 285,330	\$ 209,351		
155	TailWinds Program 14.09	kWh			240	\$1.30	\$1.30	\$3.73	\$3.73	\$ 312	\$ 896	\$ 584		
156														
157	Total Base Revenue:										\$ 27,517,756	\$ 22,773,982	\$ (4,743,774)	
158	Adjustments for Riders included in Base Rates													
159	Economic Development Adjustment	kWh			423,924,110	-\$0.00022	\$0.00000			\$ (92,456)	\$ -	\$ 92,456		
160	Environmental Cost Recovery Rider Adjustment	%			27,517,756	6.49%	0.00%			\$ 1,786,385	\$ -	\$ (1,786,385)		
161	Renewable Resource Adjustment	kWh			423,924,110	\$0.00510	\$0.00000			\$ 2,163,720	\$ -	\$ (2,163,720)		
162	Transmission Rider Adjustment	kWh			423,924,110	\$0.00407	\$0.00143			\$ 1,725,640	\$ 607,573	\$ (1,118,067)		
163	COE Adjustment	kWh			423,924,110	-\$0.00340	\$0.02463			\$ (1,443,142)	\$ 10,439,450	\$ 11,882,593		
164	Total Adjustments:										\$ 4,140,146	\$ 11,047,023	\$ 6,906,877	
165	10.04 Large General Service - Primary Service (Rate 602)													
166	Customer Charge	Bills			113	\$40.00	\$40.00	\$282.00	\$282.00	\$ 4,538	\$ 31,993	\$ 27,455		
167	Energy - First 700,000 kWh (changing to All kWh)	kWh	11,345,397	21,942,716	33,288,113	\$0.05095	\$0.05141	\$0.03339	\$0.03399	\$ 1,706,123	\$ 4,795,891	\$ (2,041,706)		
168	Energy - Excess kWh	kWh	36,328,042	72,321,568	108,649,610	\$0.04695	\$0.04737			\$ 5,131,474	\$ -	\$ -		
169	Demand per kW	kW	97,630	184,354	281,984	\$7.24	\$5.57	\$10.93	\$5.94	\$ 1,733,693	\$ 2,162,918	\$ 429,225		
170	Facilities Charge - All kW	kW	85,885	171,505	257,390	\$0.11	\$0.11	\$0.48	\$0.48	\$ 3,386	\$ 124,401	\$ 121,015		
171	Total Base Revenue:										\$ 8,579,214	\$ 7,115,203	\$ (1,464,011)	
172	Adjustments for Riders included in Base Rates													
173	Economic Development Adjustment	kWh			141,937,723	-\$0.00022	\$0.00000			\$ (30,956)	\$ -	\$ 30,956		
174	Environmental Cost Recovery Rider Adjustment	%			8,579,214	6.49%	0.00%			\$ 556,941	\$ -	\$ (556,941)		
175	Renewable Resource Adjustment	kWh			141,937,723	\$0.00510	\$0.00000			\$ 724,454	\$ -	\$ (724,454)		
176	Transmission Rider Adjustment	kWh			141,937,723	\$0.00407	\$0.00143			\$ 577,777	\$ 203,427	\$ (374,350)		
177	COE Adjustment	kWh			141,937,723	-\$0.00340	\$0.02463			\$ (483,191)	\$ 3,495,323	\$ 3,978,514		
178	Total Adjustments:										\$ 1,345,025	\$ 3,698,750	\$ 2,353,725	
179														
180	14.02 Real Time Pricing - Primary Service (Rate 662)													
181	Customer Charge	Bills			12	\$199.00	\$199.00	\$282.00	\$282.00	\$ 2,494	\$ 3,384	\$ 890		
182	Energy - All kWh	kWh	-	-	35,803,845	Real Time Pricing		Real Time Pricing		\$ -	\$ -	\$ -		
183	Total Base Revenue:										\$ 1,245,401	\$ 1,097,069	\$ (148,332)	
184	Adjustments for Riders included in Base Rates													
185	Economic Development Adjustment	kWh			35,803,845	-\$0.00022	\$0.00000			\$ (7,806)	\$ -	\$ 7,806		
186	Environmental Cost Recovery Rider Adjustment	%			1,245,401	6.49%	0.00%			\$ 80,848	\$ -	\$ (80,848)		
187	Renewable Resource Adjustment	kWh			35,803,845	\$0.00510	\$0.00000			\$ 182,744	\$ -	\$ (182,744)		
188	Transmission Rider Adjustment	kWh			35,803,845	\$0.00407	\$0.00143			\$ 145,744	\$ 51,314	\$ (94,430)		
189	COE Adjustment	kWh			35,803,845	-\$0.00340	\$0.02463			\$ (121,885)	\$ 881,697	\$ 1,003,582		
190	Total Adjustments:										\$ 279,645	\$ 933,011	\$ 653,366	
191														
192	10.04 Large General Service - Transmission Service (Rate 632)													
193	Customer Charge	Bills	-			\$40.00	\$40.00	\$282.00	\$282.00	\$ -	\$ -	\$ -		
194	Energy - First 700,000 kWh (changing to All kWh)	kWh	-			\$0.04974	\$0.04996	\$0.02920	\$0.02945	\$ -	\$ -	\$ -		
195	Energy - Excess kWh	kWh	-			\$0.04574	\$0.04592			\$ -	\$ -	\$ -		
196	Demand per kW	kW	-			\$5.88	\$4.73	\$8.26	\$5.78	\$ -	\$ -	\$ -		
197	Facilities Charge	kW	-			N/A	N/A	N/A	N/A	\$ -	\$ -	\$ -		

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual				
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual						
198	Total Base Revenue:									\$	-	\$	-	\$	-		
199	Adjustments for Riders included in Base Rates									Present	Proposed						
200	Economic Development Adjustment	kWh			-	-\$0.00022	\$0.00000			\$	-	\$	-	\$	-		
201	Environmental Cost Recovery Rider Adjustment	%			-	6.49%	0.00%			\$	-	\$	-	\$	-		
202	Renewable Resource Adjustment	kWh			-	\$0.00510	\$0.00000			\$	-	\$	-	\$	-		
203	Transmission Rider Adjustment	kWh			-	\$0.00407	\$0.00143			\$	-	\$	-	\$	-		
204	COE Adjustment	kWh			-	-\$0.00340	\$0.02463			\$	-	\$	-	\$	-		
205	Total Adjustments:											\$	-	\$	-		
206																	
207	10.05 Large General Service Time of Day - Secondary Service (Rates 611, 615, 613)																
208	Customer Charge	Bills			12	\$60.00	\$60.00	\$215.90	\$215.90	\$	720	\$	2,591	\$	1,871		
209	Facilities Charge <1,000 kW	kW			4,242	\$0.30	\$0.30	\$0.76	\$0.76	\$	1,273	\$	3,224	\$	1,951		
210	Facilities Charge >=1,000 kW	kW			-	\$0.15	\$0.15	\$0.57	\$0.57	\$	-	\$	-	\$	-		
211	Energy - On-Peak	kWh	11,459	18,816	30,275	\$0.08150	\$0.07314	\$0.05596	\$0.04903	\$	8,238	\$	1,563	\$	(6,675)		
212	Energy - Shoulder	kWh	18,847	106,291	125,138	\$0.06247	\$0.05949	\$0.04257	\$0.04368	\$	7,188	\$	5,445	\$	(1,743)		
213	Energy - Off-Peak	kWh	21,318	278,163	299,481	\$0.03721	\$0.04199	\$0.02818	\$0.03054	\$	9,331	\$	9,096	\$	(235)		
214	Demand per kW - On-Peak	kW	320	908	1,228	\$5.75	\$4.42	\$7.86	\$3.49	\$	5,244	\$	5,684	\$	440		
215	Demand per kW - Shoulder	kW	320	1,361	1,681	\$1.59	\$1.22	\$3.44	2.49	\$	2,029	\$	4,490	\$	2,460		
216	Demand per kW - Off-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$	-	\$	-	\$	-		
217	Total Base Revenue:											\$	34,024	\$	32,093	\$	(1,931)
218	Adjustments for Riders included in Base Rates									Present	Proposed						
219	Economic Development Adjustment	kWh			454,894	-\$0.00022	\$0.00000			\$	(99)	\$	-	\$	99		
220	Environmental Cost Recovery Rider Adjustment	%			34,024	6.49%	0.00%			\$	2,209	\$	-	\$	(2,209)		
221	Renewable Resource Adjustment	kWh			454,894	\$0.00510	\$0.00000			\$	2,322	\$	-	\$	(2,322)		
222	Transmission Rider Adjustment	kW			454,894	\$0.00407	\$0.00143			\$	1,852	\$	652	\$	(1,200)		
223	COE Adjustment	kWh			454,894	-\$0.00340	\$0.02463			\$	(1,549)	\$	11,202	\$	12,751		
224	Total Adjustments:											\$	4,734	\$	11,854	\$	7,120
225																	
226	10.05 Large General Service Time of Day - Primary Service (Rates 610, 614, 612)																
227	Customer Charge	Bills			-	\$60.00	\$60.00	\$282.00	\$282.00	\$	-	\$	-	\$	-		
228	Facilities Charge - All kW	kW			-	\$0.11	\$0.11	\$0.48	\$0.48	\$	-	\$	-	\$	-		
229	Energy - On-Peak	kWh	-	-	-	\$0.08115	\$0.07278	\$0.04529	\$0.03945	\$	-	\$	-	\$	-		
230	Energy - Shoulder	kWh	-	-	-	\$0.06221	\$0.05921	\$0.03457	\$0.03527	\$	-	\$	-	\$	-		
231	Energy - Off-Peak	kWh	-	-	-	\$0.03709	\$0.04184	\$0.02300	\$0.02475	\$	-	\$	-	\$	-		
232	Demand per kW - On-Peak	kW	-	-	-	\$5.71	\$4.39	\$7.56	\$3.42	\$	-	\$	-	\$	-		
233	Demand per kW - Shoulder	kW	-	-	-	\$1.57	\$1.21	\$3.36	\$2.53	\$	-	\$	-	\$	-		
234	Demand per kW - Off-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$	-	\$	-	\$	-		
235	Total Base Revenue:											\$	-	\$	-	\$	-
236	Adjustments for Riders included in Base Rates									Present	Proposed						
237	Economic Development Adjustment	kWh			-	-\$0.00022	\$0.00000			\$	-	\$	-	\$	-		
238	Environmental Cost Recovery Rider Adjustment	%			-	6.49%	0.00%			\$	-	\$	-	\$	-		
239	Renewable Resource Adjustment	kWh			-	\$0.00510	\$0.00000			\$	-	\$	-	\$	-		
240	Transmission Rider Adjustment	kW			-	\$0.00407	\$0.00143			\$	-	\$	-	\$	-		
241	COE Adjustment	kWh			-	-\$0.00340	\$0.02463			\$	-	\$	-	\$	-		
242	Total Adjustments:											\$	-	\$	-	\$	-
243																	
244	10.05 Large General Service Time of Day - Transmission Service (Rates 639, 637, 640)																
245	Customer Charge	Bills			-	\$60.00	\$60.00	\$282.00	\$282.00	\$	-	\$	-	\$	-		
246	Facilities Charge	kW			-	N/A	N/A	N/A	N/A	\$	-	\$	-	\$	-		
247	Energy - On-Peak	kWh	-	-	-	\$0.07900	\$0.07063	\$0.03853	\$0.03328	\$	-	\$	-	\$	-		
248	Energy - Shoulder	kWh	-	-	-	\$0.06066	\$0.05752	\$0.02956	\$0.02991	\$	-	\$	-	\$	-		
249	Energy - Off-Peak	kWh	-	-	-	\$0.03635	\$0.04070	\$0.02798	\$0.02980	\$	-	\$	-	\$	-		
250	Demand per kW - On-Peak	kW	-	-	-	\$4.86	\$3.74	\$5.52	\$3.17	\$	-	\$	-	\$	-		
251	Demand per kW - Shoulder	kW	-	-	-	\$1.06	\$0.82	\$2.74	\$2.48	\$	-	\$	-	\$	-		
252	Demand per kW - Off-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$	-	\$	-	\$	-		
253	Total Base Revenue:											\$	-	\$	-	\$	-
254	Adjustments for Riders included in Base Rates									Present	Proposed						
255	Economic Development Adjustment	kWh			140,646	-\$0.00022	\$0.00000			\$	(33)	\$	-	\$	33		
256	Environmental Cost Recovery Rider Adjustment	%			13,134	6.49%	0.00%			\$	853	\$	-	\$	(853)		
257	Renewable Resource Adjustment	kWh			140,646	\$0.00510	\$0.00000			\$	718	\$	-	\$	(718)		
258	Transmission Rider Adjustment	kWh			140,646	\$0.00407	\$0.00143			\$	573	\$	202	\$	(371)		
259	COE Adjustment	kWh			140,646	-\$0.00340	\$0.02463			\$	(479)	\$	3,464	\$	3,943		
260	Total Adjustments:											\$	1,631	\$	3,665	\$	2,034
261																	
262	Total Base Revenue for the COSS Class:											\$	37,389,529	\$	31,031,481	\$	(6,358,048)
263	Total Adjustments for the COSS Class:											\$	5,771,181	\$	15,694,304	\$	9,923,123

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual			
			Summer	Winter	Annual	Summer	Winter	Summer	Winter							
264	Total for the COSS Class:									\$	43,160,710	\$	46,725,785	\$	3,565,075	8.26%
265																
266																
267	11.01 Standby Service - Option A: Firm - Secondary Service (Rates 947, 948, 949)															
268	Customer Charge	Bills			-	\$199.00	\$199.00	\$242.24	\$242.24							
269	Facilities Charge per month per kW of Contracted Backup	kW			-	\$0.30	\$0.30	\$0.55	\$0.55							
270	Reservation Charge per kW of Contracted Backup	kW			-	\$0.85069	\$0.09697	\$0.65645	\$0.22355							
271	Metered Demand per day per kW On-Peak Backup	kW			-	\$0.49076	\$0.32187	\$0.54794	\$0.43005							
272	Energy - On-Peak	kWh			-	\$0.08150	\$0.07314	\$0.05596	\$0.04903							
273	Energy - Shoulder	kWh			-	\$0.06247	\$0.05949	\$0.04257	\$0.04368							
274	Energy - Off-Peak	kWh			-	\$0.03721	\$0.04199	\$0.02818	\$0.03054							
275																
276	Total:															
277	11.01 Standby Service - Option A: Firm - Primary Service (Rates 944, 945, 946)															
278	Customer Charge	Bills			-	\$199.00	\$199.00	\$304.33	\$304.33							
279	Facilities Charge per month per kW of Backup	kW			-	\$0.11	\$0.11	\$0.45	\$0.45							
280	Reservation Charge per kW of Contracted Backup	kW			-	\$0.84590	\$0.09634	\$0.62837	\$0.21403							
281	Metered Demand per day per kW On-Peak Backup	kW			-	\$0.48683	\$0.31978	\$0.52464	\$0.40800							
282	Energy - On-Peak	kWh			-	\$0.08115	\$0.07278	\$0.04529	\$0.03945							
283	Energy - Shoulder	kWh			-	\$0.06221	\$0.05921	\$0.03457	\$0.03527							
284	Energy - Off-Peak	kWh			-	\$0.03709	\$0.04181	\$0.02300	\$0.02475							
285	Conservation Improvement Program				-											
286	Total:															
287	11.01 Standby Service - Option A: Firm - Transmission Service (Rates 941, 942, 943)															
288	Customer Charge	Bills			12	\$199.00	\$199.00	\$304.33	\$304.33							
289	Facilities Charge per month per kW of Backup	kW	3,755	5,781	9,536	N/A	N/A	N/A	N/A							
290	Reservation Charge per kW of Contracted Backup	kW	3,755	5,781	9,536	\$0.81704	\$0.09254	\$0.58422	\$0.19898							
291	Metered Demand per day per kW On-Peak Backup	kW			-	\$0.35865	\$0.28694	\$0.48812	\$0.37420							
292	Energy - On-Peak	kWh	11,771	24,871	36,642	\$0.07900	\$0.07063	\$0.03853	\$0.03328							
293	Energy - Shoulder	kWh	20,689	23,640	44,329	\$0.06066	\$0.05752	\$0.02956	\$0.02991							
294	Energy - Off-Peak	kWh	21,888	37,787	59,675	\$0.03635	\$0.04070	\$0.02798	\$0.02980							
295	Conservation Improvement Program				-											
296	Total:															
297	11.01 Standby Service - Option B: Non-Firm - Secondary Service (Rates 956, 957, 958)															
298	Customer Charge	Bills			-	\$199.00	\$199.00	\$242.24	\$242.24							
299	Facilities Charge per month per kW of Backup	kW			-	\$0.30	\$0.30	\$0.55	\$0.55							
300	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A							
301	Energy - Shoulder	kWh			-	\$0.06247	\$0.05949	\$0.04257	\$0.04368							
302	Energy - Off-Peak	kWh			-	\$0.03721	\$0.04199	\$0.02818	\$0.03054							
303	Conservation Improvement Program				-											
304	Total:															
305	11.01 Standby Service - Option B: Non-Firm - Primary Service (Rates 953, 954, 955)															
306	Customer Charge	Bills			-	\$199.00	\$199.00	\$304.33	\$304.33							
307	Facilities Charge per month per kW of Backup	kW			-	\$0.11	\$0.11	\$0.45	\$0.45							
308	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A							
309	Energy - Shoulder	kWh			-	\$0.06221	\$0.05921	\$0.03457	\$0.03527							
310	Energy - Off-Peak	kWh			-	\$0.03709	\$0.04181	\$0.02300	\$0.02475							
311	Conservation Improvement Program				-											
312	Total:															
313	11.01 Standby Service - Option B: Non-Firm - Transmission Service (Rates 950, 951, 952)															
314	Customer Charge	Bills			-	\$199.00	\$199.00	\$304.33	\$304.33							
315	Facilities Charge per month per kW of Backup	kW			-	N/A	N/A	N/A	N/A							
316	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A							
317	Energy - Shoulder	kWh			-	\$0.06066	\$0.05752	\$0.02956	\$0.02991							
318	Energy - Off-Peak	kWh			-	\$0.03635	\$0.04070	\$0.02798	\$0.02980							
319	Conservation Improvement Program				-											
320	Total:															
321																
322																
323	11.02 Irrigation Service - Option 1: Non-Time-of-Use (Rate 703)															
324	Customer Charge	Bills			79	\$1.00	\$1.00	\$24.30	\$24.30	\$	79	\$	1,925	\$	1,846	
325	Energy	kWh	272,835	44,562	317,397	\$0.06896	\$0.05145	\$0.05552	\$0.03652	\$	21,107	\$	16,775	\$	(4,332)	
326	18% Return of Distribution Facilities				-					\$	5,158	\$	5,158	\$	-	
327	Total Base Revenue:															
328	Adjustments for Riders included in Base Rates															
329	Economic Development Adjustment	kWh			317,397	Present -\$0.00023	Proposed \$0.00000			\$	(73)	\$	-	\$	73	

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
330	Environmental Cost Recovery Rider Adjustment	%			26,344	6.49%	0.00%			\$ 1,710	\$ -	\$ (1,710)	
331	Renewable Resource Adjustment	kWh			317,397	\$0.00510	\$0.00000			\$ 1,620	\$ -	\$ (1,620)	
332	Transmission Rider Adjustment	kWh			317,397	\$0.00000	\$0.00000			\$ -	\$ -	\$ -	
333	COE Adjustment	kWh			317,397	-\$0.00520	\$0.02283			\$ (1,651)	\$ 7,245	\$ 8,896	
334	Total Adjustments:									\$ 1,606	\$ 7,245	\$ 5,639	
335													
336	11.02 Irrigation Service - Option 2 (Rates 704, 705, 706)												
337	Customer Charge	Bills			164	\$5.00	\$5.00	\$24.30	\$24.30	\$ 814	\$ 3,980	\$ 3,166	
338	Energy - Declared-Peak	kWh	5,043	504	5,547	\$0.14450	\$0.08760	\$0.17685	\$0.14297	\$ 1,546	\$ 964	\$ (582)	
339	Energy - Intermediate	kWh	261,095	24,342	285,437	\$0.05441	\$0.05111	\$0.04155	\$0.04217	\$ 15,083	\$ 11,875	\$ (3,208)	
340	Energy - Off-Peak	kWh	231,192	25,683	256,875	\$0.02642	\$0.02612	\$0.01802	\$0.02015	\$ 6,762	\$ 4,684	\$ (2,079)	
341	Demand per kW - Declared-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
342	Demand per kW - Intermediate	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
343	Demand per kW - Off-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
344	18% Return of Distribution Facilities				-					\$ 5,196	\$ 5,196	\$ -	
345	Total Base Revenue:									\$ 29,401	\$ 26,698	\$ (2,703)	
346	Adjustments for Riders included in Base Rates					Present	Proposed						
347	Economic Development Adjustment	kWh			547,859	-\$0.00023	\$0.00000			\$ (124)	\$ -	\$ 124	
348	Environmental Cost Recovery Rider Adjustment	%			29,401	6.49%	0.00%			\$ 1,908	\$ -	\$ (1,908)	
349	Renewable Resource Adjustment	kWh			547,859	\$0.00510	\$0.00000			\$ 2,796	\$ -	\$ (2,796)	
350	Transmission Rider Adjustment	kWh			547,859	\$0.00000	\$0.00000			\$ -	\$ -	\$ -	
351	COE Adjustment	kWh			547,859	-\$0.00520	\$0.02283			\$ (2,851)	\$ 12,505	\$ 15,356	
352	Total Adjustments:									\$ 1,730	\$ 12,505	\$ 10,776	
353													
354	Total Base Revenue for the COSS Class:									\$ 55,745	\$ 50,557	\$ (5,188)	
355	Total Adjustments for the COSS Class:									\$ 3,336	\$ 19,750	\$ 16,414	
356	Total for the COSS Class:									\$ 59,081	\$ 70,307	\$ 11,226	19.00%
357													
358													
359	11.03 Outdoor Lighting - Metered - Energy Only (Rate 748)												
360	Customer Charge	Bills			1,140	\$2.00	\$2.00	\$2.00	\$2.00	\$ 2,281	\$ 2,281	\$ (0)	
361	Energy	kWh			1,220,905	\$0.06978	\$0.06978	\$0.07047	\$0.07047	\$ 84,559	\$ 86,032	\$ 1,474	
362	Total Base Revenue:									\$ 86,839	\$ 88,313	\$ 1,474	
363	Adjustments for Riders included in Base Rates					Present	Proposed						
364	Economic Development Adjustment	kWh			1,220,905	-\$0.00040	\$0.00000			\$ (484)	\$ -	\$ 484	
365	Environmental Cost Recovery Rider Adjustment	%			86,839	6.49%	0.00%			\$ 5,637	\$ -	\$ (5,637)	
366	Renewable Resource Adjustment	kWh			1,220,905	\$0.00511	\$0.00000			\$ 6,244	\$ -	\$ (6,244)	
367	Transmission Rider Adjustment	kWh			1,220,905	\$0.00306	\$0.00108			\$ 3,735	\$ 1,315	\$ (2,420)	
368	COE Adjustment	kWh			1,220,905	-\$0.00333	\$0.02470			\$ (4,060)	\$ 30,162	\$ 34,222	
369	Total Adjustments:									\$ 11,073	\$ 31,477	\$ 20,404	
370													
371	11.03 Outdoor Lighting - Non-Metered - Energy Only (Rate 749)												
372		kWh			2,533,051	\$0.00	\$0.00	\$0.00	\$0.00				
373	Monthly charge for connected KW	kW			618	\$ 23.84	\$ 23.84	\$24.08	\$24.08	\$ 177,817	\$ 178,494	\$ 677	
374	Total Base Revenue:									\$ 177,817	\$ 178,494	\$ 677	
375													
376	Non Standard Ligtig	kwh			793,280	\$0.06978	\$0.06978	\$0.07047	\$0.07047	\$ 41,518	\$ 55,899	\$ 14,381	
377													
378	Adjustments for Riders included in Base Rates					Present	Proposed						
379	Economic Development Adjustment	kWh			3,326,331	-\$0.00040	\$0.00000			\$ (1,318)	\$ -	\$ 1,318	
380	Environmental Cost Recovery Rider Adjustment	%			219,335	6.49%	0.00%			\$ 14,238	\$ -	\$ (14,238)	
381	Renewable Resource Adjustment	kWh			3,326,331	\$0.00511	\$0.00000			\$ 17,012	\$ -	\$ (17,012)	
382	Transmission Rider Adjustment	kWh			3,326,331	\$0.00306	\$0.00108			\$ 10,177	\$ 3,583	\$ (6,594)	
383	COE Adjustment	kWh			3,326,331	-\$0.00333	\$0.02470			\$ (11,061)	\$ 82,175	\$ 93,236	
384	Total Adjustments:									\$ 29,048	\$ 85,758	\$ 56,710	
385													
386	11.03 Sign Lighting (Rate 744)												
387	Monthly charge for connected KW	kW			119	\$23.84	\$23.84	\$24.08	\$24.08	\$ 33,148	\$ 34,515	\$ 1,367	
388	Energy	kWh			489,810					\$ -	\$ -	\$ -	
389	Total Base Revenue:									\$ 33,148	\$ 34,515	\$ 1,367	
390	Adjustments for Riders included in Base Rates					Present	Proposed						
391	Economic Development Adjustment	kWh			489,810	-\$0.00040	\$0.00000			\$ (194)	\$ -	\$ 194	
392	Environmental Cost Recovery Rider Adjustment	%			33,148	6.49%	0.00%			\$ 2,152	\$ -	\$ (2,152)	
393	Renewable Resource Adjustment	kWh			489,810	\$0.00511	\$0.00000			\$ 2,505	\$ -	\$ (2,505)	
394	Transmission Rider Adjustment	kWh			489,810	\$0.00306	\$0.00108			\$ 1,499	\$ 528	\$ (971)	
395	COE Adjustment	kWh			489,810	-\$0.00333	\$0.02470			\$ (1,629)	\$ 12,100	\$ 13,729	

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual			
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual					
396	Total Adjustments:									\$	4,332	\$	12,628	\$	8,296	
397																
398	11.04 Outdoor Lighting - Street & Area Lighting (Rate 741)									\$	339,322.31	\$	357,221.86			
399	Type:	kWh/lt	Annual Kwh			Quantity										
400	MV-6	Lts	70	7,286,717	104,096	\$7.01	\$7.01	\$	7.12	\$7.12						
401	MV-6PT	Lts	70	151,859	2,169	\$10.00	\$10.00	\$	10.16	\$10.16						
402	MV-11	Lts	100	9,639	96	\$12.70	\$12.70	\$	12.90	\$12.90						
403	MV-21	Lts	154	70,849	460	\$16.72	\$16.72	\$	16.99	\$16.99						
404	MV-35	Lts	260	-	-	\$24.53	\$24.53	\$	24.92	\$24.92						
405	MV-55	Lts	366	-	-	\$31.36	\$31.36	\$	31.86	\$31.86						
406	MA-8	Lts	41	192,525	4,696	\$8.46	\$8.46	\$	8.59	\$8.59						
407	MA-14	Lts	70	842	12	\$16.10	\$16.10	\$	16.36	\$16.36						
408	MA-20	Lts	98	-	-	\$18.38	\$18.38	\$	18.67	\$18.67						
409	MA-36	Lts	156	32,557	209	\$18.00	\$18.00	\$	18.29	\$18.29						
410	MA-110	Lts	369	132,401	359	\$38.41	\$38.41	\$	39.02	\$39.02						
411	HPS-9	Lts	44	3,743,878	85,088	\$7.52	\$7.52	\$	7.64	\$7.64						
412	HPS-9PT	Lts	44	144,463	3,283	\$9.72	\$9.72	\$	9.87	\$9.87						
413	HPS-14	Lts	64	150,420	2,350	\$11.71	\$11.71	\$	11.90	\$11.90						
414	HPS-14PT	Lts	64	36,488	570	\$12.53	\$12.53	\$	12.73	\$12.73						
415	HPS-19	Lts	83	87,748	1,057	\$13.61	\$13.61	\$	13.83	\$13.83						
416	HPS-23	Lts	102	681,430	6,681	\$15.40	\$15.40	\$	15.65	\$15.65						
417	HPS-44	Lts	156	714,834	4,582	\$19.01	\$19.01	\$	19.31	\$19.31						
418	UHPS23	Lts	102	1,289	13	\$17.99	\$17.99	\$	18.11	\$18.11						
419	UHPS9	Lts	44	2,671	61	\$9.86	\$9.86	\$	10.10	\$10.10						
420	UMV6	Lts	70	1,815	26	\$8.97	\$8.97	\$	9.58	\$9.58						
421	Seasonal Charge				92	\$10.80	\$10.80		\$32.79	\$32.79						
422	Total Base Revenue:			13,442,425						\$	1,728,486	\$	1,757,250	\$	1,757,250	
423					\$	10,632	\$25,062.92									
424	~~MH Lights that were not accounted for in the forecast -~~				\$	(1,728,486)										
425																
426																
427	Adjustments for Riders included in Base Rates					Present	Proposed									
428	Economic Development Adjustment	kWh			13,442,425	-\$0.00040	\$0.00000			\$	(5,325)	\$	-	\$	5,325	
429	Environmental Cost Recovery Rider Adjustment	%			1,728,486	6.49%	0.00%			\$	112,207	\$	-	\$	(112,207)	
430	Renewable Resource Adjustment	kWh			13,442,425	\$0.00511	\$0.00000			\$	68,749	\$	-	\$	(68,749)	
431	Transmission Rider Adjustment	kWh			13,442,425	\$0.00306	\$0.00108			\$	41,127	\$	14,480	\$	(26,646)	
432	COE Adjustment	kWh			13,442,425	-\$0.00333	\$0.02470			\$	(44,703)	\$	332,088	\$	376,791	
433	Total Adjustments:									\$	172,054	\$	346,568	\$	174,514	
434																
435	11.04 Outdoor Lighting - Flood Lighting (Rate 743)															
436	Type:	kWh/lt	Annual Kwh			Quantity										
437	400MV-F	Lts	154	306,361	1,989	\$17.35	\$17.35	\$17.63	\$17.63							
438	400MA-F	Lts	156	1,082,994	6,942	\$18.49	\$18.49	\$18.78	\$18.78							
439	400HPS-F	Lts	156	1,813,773	11,627	\$18.90	\$18.90	\$19.20	\$19.20							
440	1000MV-F	Lts	366	1,652,385	4,515	\$30.44	\$30.44	\$30.93	\$30.93							
441	1000MA-F	Lts	308	4,623	15	\$32.11	\$32.11	\$32.62	\$32.62							
442	1M-HPSF	Lts	371	4,801	13	\$37.32	\$37.32	\$37.91	\$37.91							
443	U1M-MAF	Lts	371	-	-	\$39.44	\$39.44	\$21.66	\$21.66							
444	UNDERGROUND SERVICE:					\$1.96	\$1.96	\$2.46	\$2.46							
445																
446	Total Base Revenue:			4,864,937						\$	530,119	\$	533,700	\$	3,581	
447	Adjustments for Riders included in Base Rates					Present	Proposed									
448	Economic Development Adjustment	kWh			4,558,576	-\$0.00040	\$0.00000			\$	(1,806)	\$	-	\$	1,806	
449	Environmental Cost Recovery Rider Adjustment	%			530,119	6.49%	0.00%			\$	34,413	\$	-	\$	(34,413)	
450	Renewable Resource Adjustment	kWh			4,558,576	\$0.00511	\$0.00000			\$	23,313	\$	-	\$	(23,313)	
451	Transmission Rider Adjustment	kWh			4,558,576	\$0.00306	\$0.00108			\$	13,947	\$	4,910	\$	(9,036)	
452	COE Adjustment	kWh			4,558,576	-\$0.00333	\$0.02470			\$	(15,160)	\$	112,617	\$	127,777	
453	Total Adjustments:									\$	54,707	\$	117,528	\$	62,821	
454																
455	Total Base Revenue for the COSS Class:									\$	2,597,928	\$	2,648,173	\$	50,245	
456	Total Adjustments for the COSS Class:									\$	271,215	\$	593,959	\$	322,744	
457	Total for the COSS Class:									\$	2,869,143	\$	3,242,131	\$	372,988	13.00%
458																
459																
460																
461	11.05 Municipal Pumping - Secondary Service (Rate 872)															

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter				
462	Customer Charge	Bills			6,929	\$4.00	\$4.00	\$26.50	\$26.50				
463	Facilities Charge (Changing per Month to per KW)	kW			-	\$4.00	\$4.00	\$0.65	\$0.65				
464	Energy - All kWh	kWh	5,736,571	10,722,486	16,459,057	\$0.06523	\$0.05950	\$0.05159	\$0.03490				
465	Total Base Revenue:									\$ 1,039,969	\$ 928,426	\$ (111,543)	
466	Adjustments for Riders included in Base Rates					Present	Proposed						
467	Economic Development Adjustment	kWh			16,459,057	-\$0.00022	\$0.00000			\$ (3,667)	\$ -	\$ 3,667	
468	Environmental Cost Recovery Rider Adjustment	%			1,039,969	6.49%	0.00%			\$ 67,512	\$ -	\$ (67,512)	
469	Renewable Resource Adjustment	kWh			16,459,057	\$0.00510	\$0.00000			\$ 84,012	\$ -	\$ (84,012)	
470	Transmission Rider Adjustment	kWh			16,459,057	\$0.00421	\$0.00148			\$ 69,279	\$ 24,392	\$ (44,887)	
471	COE Adjustment	kWh			16,459,057	-\$0.00347	\$0.02456			\$ (57,088)	\$ 404,259	\$ 461,347	
472	Total Adjustments:									\$ 160,049	\$ 428,652	\$ 268,603	
473	11.05 Municipal Pumping - Primary Service (Rate 874)												
475	Customer Charge	Bills			-	\$4.00	\$4.00	\$26.50	\$26.50				
476	Facilities Charge (Changing per Month to per KW)	KW			-	\$2.68	\$2.68	\$0.65	\$0.65				
477	Energy - All kWh	kWh			-	\$0.06494	\$0.05922	\$0.05159	\$0.03490				
478	Total Base Revenue:									\$ -	\$ -	\$ -	
479	11.06 Civil Defense - Fire Sirens (Rate 843)												
480	Customer Charge	Bills			816	\$1.00	\$1.00	\$1.22	\$1.22				
482	Load Charge	HP			5,658	\$0.53193	\$0.53193	\$0.42962	\$0.42962				
483	Total Base Revenue:									\$ 3,727	\$ 3,426	\$ (300)	
484	Adjustments for Riders included in Base Rates					Present	Proposed						
485	Economic Development Adjustment	kWh			-	-\$0.00022	\$0.00000			\$ -	\$ -	\$ -	
486	Environmental Cost Recovery Rider Adjustment	%			3,727	6.49%	0.00%			\$ 242	\$ -	\$ (242)	
487	Renewable Resource Adjustment	kWh			-	\$0.00510	\$0.00000			\$ -	\$ -	\$ -	
488	Transmission Rider Adjustment	kWh			-	\$0.00421	\$0.00148			\$ -	\$ -	\$ -	
489	COE Adjustment	kWh			-	-\$0.00347	\$0.02456			\$ -	\$ -	\$ -	
490	Total Adjustments:									\$ 242	\$ -	\$ (242)	
491	Total Base Revenue for the COSS Class:									\$ 1,043,696	\$ 931,853	\$ (111,843)	
492	Total Adjustments for the COSS Class:									\$ 160,291	\$ 428,652	\$ 268,361	
493	Total for the COSS Class:									\$ 1,203,986	\$ 1,360,504	\$ 156,518	13.00%
494	14.01 Water Heating - Controlled Service (Rate 191)												
495	Customer Charge	Bills			68,012	\$1.00	\$1.00	\$4.00	\$4.00	\$ 68,012	\$ 272,047	\$ 204,035	
496	Facilities Charges per Month	Bills			68,012	\$1.00	\$1.00	\$2.00	\$2.00	\$ 68,012	\$ 136,023	\$ 68,012	
497	Energy - All kWh	kWh	4,511,887	10,487,484	14,999,371	\$0.05773	\$0.05638	\$0.03317	\$0.02868	\$ 851,756	\$ 450,445	\$ (401,311)	
498	Total Base Revenue:									\$ 987,779	\$ 858,515	\$ (129,264)	
499	Adjustments for Riders included in Base Rates					Present	Proposed						
500	Economic Development Adjustment	kWh			14,999,371	-\$0.00023	\$0.00000			\$ (3,470)	\$ -	\$ 3,470	
501	Environmental Cost Recovery Rider Adjustment	%			987,779	6.49%	0.00%			\$ 64,123	\$ -	\$ (64,123)	
502	Renewable Resource Adjustment	kWh			14,999,371	\$0.00510	\$0.00000			\$ 76,559	\$ -	\$ (76,559)	
503	Transmission Rider Adjustment	kWh			14,999,371	\$0.00055	\$0.00019			\$ 8,190	\$ 2,884	\$ (5,307)	
504	COE Adjustment	kWh			14,999,371	-\$0.00321	\$0.02482			\$ (48,149)	\$ 372,283	\$ 420,432	
505	Total Adjustments:									\$ 97,254	\$ 375,167	\$ 277,913	
506	Total Base Revenue for the COSS Class:									\$ 987,779	\$ 858,515	\$ (129,264)	
507	Total Adjustments for the COSS Class:									\$ 97,254	\$ 375,167	\$ 277,913	
508	Total for the COSS Class:									\$ 1,085,033	\$ 1,233,682	\$ 148,649	13.70%
509	14.02 Real Time Pricing - Secondary Service (Rate 664)												
510	Administrative Charge	Bills			-	\$ 199.00	\$ 199.00	\$282.00	\$282.00				
511	Consumption Change from CBL	kWh			-								
512	Conservation Improvement Program				-								
513	Total:												
514	14.02 Real Time Pricing - Primary Service (Rate 662)												
515	Administrative Charge	Bills			-	\$ 199.00	\$ 199.00	\$282.00	\$282.00				
516	Consumption Change from CBL	kWh			-								
517	Conservation Improvement Program				-								
518	Total:												
519	14.02 Real Time Pricing - Transmission Service (Rate 660)												
520	Administrative Charge	Bills			-	\$ 199.00	\$ 199.00	\$282.00	\$282.00				
521	Consumption Change from CBL	kWh			-								
522	Conservation Improvement Program				-								
523	Total:												
524	14.02 Real Time Pricing - Transmission Service (Rate 660)												
525	Administrative Charge	Bills			-	\$ 199.00	\$ 199.00	\$282.00	\$282.00				
526	Consumption Change from CBL	kWh			-								
527	Conservation Improvement Program				-								

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter				
528	Total:												
529	14.03 Large General Service Rider												
530	Administrative Charge	Bills			-	\$199.00	\$199.00	\$282.00	\$282.00				
531	Fixed Rate Energy Pricing (FREPE) Peak	kWh			-								
532	Fixed Rate Energy Pricing (FREPE) Shoulder	kWh			-								
533	Fixed Rate Energy Pricing (FREPE) Off-Peak	kWh			-								
534	Capacity Purchase	kW			-								
535	Conservation Improvement Program				-								
536	Total:												
537													
538	14.04 Controlled Service - Interruptible Load Rider CT Metering - Option 1 (Rates 170, 165, 881)												
539	Customer Charge	Bills			275	\$4.00	\$4.00	\$20.20	\$20.20	\$	13,189	\$	53,417
540	Facilities Charge	kW			670,471	\$0.08	\$0.08	\$0.76	\$0.76	\$	53,638	\$	455,920
541	Energy - All kWh	kWh	8,241,990	57,098,286	65,340,276	\$0.03166	\$0.03044	\$0.01060	\$0.01005	\$	1,999,013	\$	(1,337,851)
542	Penalty kWh	kWh	15,917	99,535	115,452	\$0.39448	\$0.12726	\$0.41350	\$0.14322	\$	22,480	\$	(22,480)
543	Revenue Adjustment:									\$	779		
544	Total Base Revenue:									\$	2,089,099	\$	1,237,326
545	Adjustments for Riders included in Base Rates					Present	Proposed						
546	Economic Development Adjustment	kWh			65,455,728	-\$0.00013	\$0.00000			\$	(8,525)	\$	8,525
547	Environmental Cost Recovery Rider Adjustment	%			2,089,099	6.49%	0.00%			\$	135,619	\$	(135,619)
548	Renewable Resource Adjustment	kWh			65,455,728	\$0.00510	\$0.00000			\$	333,718	\$	(333,718)
549	Transmission Rider Adjustment	kWh			65,455,728	\$0.00081	\$0.00028			\$	52,973	\$	(34,322)
550	COE Adjustment	kWh			65,455,728	-\$0.00259	\$0.02544			\$	(169,429)	\$	1,834,724
551	Total Adjustments:									\$	344,356	\$	1,339,589
552													
553	14.04 Controlled Service - Interruptible Load Rider CT Metering - Option 2 (Rates 168, 268, 169, 269)												
554	Customer Charge	Bills	45	89	134	\$5.00	\$5.00	\$20.20	\$20.20	\$	669	\$	2,035
555	Facilities Charge	kW	4,480	8,200	12,680	\$0.08	\$0.08	\$0.76	\$0.76	\$	1,014	\$	8,623
556	Energy - All kWh	kWh	84,310	1,049,540	1,133,850	\$0.03336	\$0.03208	\$0.01060	\$0.01005	\$	36,482	\$	(25,060)
557	Control Period Demand	kW	74	425	499	\$7.29	\$5.61	\$11.38	\$6.25	\$	2,924	\$	409
558	Total Base Revenue:									\$	41,089	\$	23,763
559	Adjustments for Riders included in Base Rates					Present	Proposed						
560	Economic Development Adjustment	kWh			1,133,850	-\$0.00013	\$0.00000			\$	(148)	\$	148
561	Environmental Cost Recovery Rider Adjustment	%			41,089	6.49%	0.00%			\$	2,667	\$	(2,667)
562	Renewable Resource Adjustment	kWh			1,133,850	\$0.00510	\$0.00000			\$	5,781	\$	(5,781)
563	Transmission Rider Adjustment	kWh			1,133,850	\$0.00081	\$0.00028			\$	918	\$	(595)
564	COE Adjustment	kWh			1,133,850	-\$0.00259	\$0.02544			\$	(2,935)	\$	31,782
565	Total Adjustments:									\$	6,283	\$	22,887
566													
567	14.05 Controlled Service - Interruptible Load Rider Self-Contained Metering (Rates 190, 185, 882)												
568	Customer Charge	Bills			-	\$2.00	\$2.00	\$8.50	\$8.50	\$	184,644	\$	600,092
569	Facilities Charge	Bills			92,322	\$5.00	\$5.00	\$11.70	\$11.70	\$	461,609	\$	618,557
570	Energy - All kWh	kWh	12,458,471	117,741,633	130,200,104	\$0.03659	\$0.03451	\$0.01111	\$0.01037	\$	4,519,031	\$	(3,160,163)
571	Penalty kWh	kWh	279	2,262	2,541	\$0.38606	\$0.12924	\$0.41350	\$0.16537	\$	488	\$	(488)
572	Total Base Revenue:									\$	5,165,773	\$	3,223,770
573	Adjustments for Riders included in Base Rates					Present	Proposed						
574	Economic Development Adjustment	kWh			130,200,104	-\$0.00013	\$0.00000			\$	(16,958)	\$	16,958
575	Environmental Cost Recovery Rider Adjustment	%			5,165,773	6.49%	0.00%			\$	335,349	\$	(335,349)
576	Renewable Resource Adjustment	kWh			130,200,104	\$0.00510	\$0.00000			\$	663,810	\$	(663,810)
577	Transmission Rider Adjustment	kWh			130,200,104	\$0.00081	\$0.00028			\$	105,370	\$	(68,271)
578	COE Adjustment	kWh			130,200,104	-\$0.00259	\$0.02544			\$	(337,018)	\$	3,649,509
579	Total Adjustments:									\$	750,553	\$	2,599,037
580													
581													
582	Total Base Revenue for the COSS Class:									\$	7,295,962	\$	4,484,859
583	Total Adjustments for the COSS Class:									\$	1,101,193	\$	5,062,706
584	Total for the COSS Class:									\$	8,397,155	\$	9,547,565
585													13.70%
586													
587													
588	14.06 Controlled Service - Deferred Load Rider (Rates 197, 195, 883)												
589	Customer Charge	Bills			9,515	\$3.00	\$3.00	\$8.80	\$8.80	\$	28,544	\$	55,185
590	Facilities Charge	Bills			9,515	\$4.00	\$4.00	\$11.60	\$11.60	\$	38,058	\$	72,311
591	Energy - All kWh	kWh	1,115,150	15,873,655	16,988,805	\$0.05154	\$0.05002	\$0.02762	\$0.02516	\$	851,475	\$	(421,266)
592	Penalty kWh	kWh	37	1,828	1,865	\$0.33802	\$0.11510	\$0.35916	\$0.16537	\$	316	\$	(316)
593	Total Base Revenue:									\$	918,394	\$	624,307

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
594	Adjustments for Riders included in Base Rates												
595	Economic Development Adjustment	kWh			16,990,670	-\$0.00016	\$0.00000			\$ (2,758)	\$ -	\$ 2,758	
596	Environmental Cost Recovery Rider Adjustment	%			918,394	6.49%	0.00%			\$ 59,620	\$ -	\$ (59,620)	
597	Renewable Resource Adjustment	kWh			16,990,670	\$0.00510	\$0.00000			\$ 86,658	\$ -	\$ (86,658)	
598	Transmission Rider Adjustment	kWh			16,990,670	\$0.00089	\$0.00031			\$ 15,168	\$ 5,341	\$ (9,828)	
599	COE Adjustment	kWh			16,990,670	-\$0.00241	\$0.02562			\$ (40,940)	\$ 435,309	\$ 476,249	
600	Total Adjustments:									\$ 117,748	\$ 440,650	\$ 322,901	
601													
602	14.07 Fixed Time of Service Rider - Self-Contained Metering (Rates 301, 884)												
603	Customer Charge	Bills	1,346	2,704	4,049	\$1.00	\$1.00	\$6.70	\$6.70	\$ 4,050	\$ 27,132	\$ 23,082	
604	Facilities Charge	Bills	1,346	2,704	4,049	\$3.00	\$3.00	\$6.00	\$6.00	\$ 12,148	\$ 24,297	\$ 12,148	
605	Energy - All kWh	kWh	133,534	6,324,579	6,458,113	\$0.02774	\$0.02937	\$0.01525	\$0.01687	\$ 189,457	\$ 108,701	\$ (80,756)	
606	Penalty kWh	kWh	15,850	341,830	357,680	\$0.09400	\$0.07385	\$0.06736	\$0.04602	\$ 37,213	\$ -	\$ (37,213)	
607	Total Base Revenue:									\$ 242,868	\$ 160,130	\$ (82,739)	
608	Adjustments for Riders included in Base Rates												
609	Economic Development Adjustment	kWh			6,815,793	-\$0.00016	\$0.00000			\$ (1,106)	\$ -	\$ 1,106	
610	Environmental Cost Recovery Rider Adjustment	%			242,868	6.49%	0.00%			\$ 15,766	\$ -	\$ (15,766)	
611	Renewable Resource Adjustment	kWh			6,815,793	\$0.00510	\$0.00000			\$ 34,763	\$ -	\$ (34,763)	
612	Transmission Rider Adjustment	kWh			6,815,793	\$0.00089	\$0.00031			\$ 6,085	\$ 2,142	\$ (3,942)	
613	COE Adjustment	kWh			6,815,793	-\$0.00241	\$0.02562			\$ (16,422)	\$ 174,624	\$ 191,046	
614	Total Adjustments:									\$ 39,086	\$ 176,766	\$ 137,681	
615													
616	14.07 Fixed Time of Service Rider - CT Metering (Rates 302, 885)												
617	Customer Charge	Bills	224	451	674	\$1.50	\$1.50	\$6.70	\$6.70	\$ 1,012	\$ 4,519	\$ 3,507	
618	Facilities Charge	Bills	224	451	674	\$19.00	\$19.00	\$38.00	\$38.00	\$ 12,815	\$ 25,631	\$ 12,815	
619	Energy - All kWh	kWh	138,334	4,855,242	4,993,576	\$0.02774	\$0.02937	\$0.01525	\$0.01687	\$ 146,436	\$ 83,994	\$ (62,442)	
620	Penalty kWh	kWh	21,303	131,829	153,132	\$0.09400	\$0.07385	\$0.06736	\$0.04602	\$ 16,201	\$ -	\$ (16,201)	
621	Total Base Revenue:									\$ 176,464	\$ 114,143	\$ (62,321)	
622	Adjustments for Riders included in Base Rates												
623	Economic Development Adjustment	kWh			5,146,708	-\$0.00016	\$0.00000			\$ (835)	\$ -	\$ 835	
624	Environmental Cost Recovery Rider Adjustment	%			176,464	6.49%	0.00%			\$ 11,456	\$ -	\$ (11,456)	
625	Renewable Resource Adjustment	kWh			5,146,708	\$0.00510	\$0.00000			\$ 26,250	\$ -	\$ (26,250)	
626	Transmission Rider Adjustment	kWh			5,146,708	\$0.00089	\$0.00031			\$ 4,595	\$ 1,618	\$ (2,977)	
627	COE Adjustment	kWh			5,146,708	-\$0.00241	\$0.02562			\$ (12,401)	\$ 131,861	\$ 144,262	
628	Total Adjustments:									\$ 29,064	\$ 133,479	\$ 104,415	
629													
630	14.07 Fixed Time of Service Rider - Primary CT Metering (Rates 303, 886)												
631	Customer Charge	Bills			-	\$3.00	\$3.00	\$6.70	\$6.70				
632	Facilities Charge	Bills			-	\$9.00	\$9.00	\$18.00	\$18.00				
633	Energy - All kWh	kWh			-	\$0.02763	\$0.02926	\$0.01519	\$0.01680				
634	Penalty kWh	kWh			-	\$0.09389	\$0.07374	\$0.06736	\$0.04602				
635													
636													
637													
638	Total Base Revenue for the COSS Class:									\$ 1,337,726	\$ 898,580	\$ (439,146)	
639	Total Adjustments for the COSS Class:									\$ 185,898	\$ 750,895	\$ 564,997	
640	Total for the COSS Class:									\$ 1,523,624	\$ 1,649,475	\$ 125,851	8.26%
641													
642													
643													
644	Total Base Revenue:									\$ 128,789,562	\$ 116,054,916	\$ (12,734,646)	
645	Total Adjustments:									\$ 19,282,388	\$ 47,732,355	\$ 28,449,967	
646	TOTAL :									\$ 148,071,950	\$ 163,787,271	\$ 15,715,320	10.61%

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
1	9.01 Residential Service (Rate 101)												
2	Customer Charge	Bills			526,602	\$8.00	\$8.00	\$8.85	\$ 8.85	\$ 4,212,722	\$ 4,660,169	\$ 447,447	
3	Seasonal Fixed Charge	Bills			6	\$32.00	\$32.00	\$35.40	\$ 35.40	\$ 415	\$ 217	\$ (197)	
4	Energy Tier 1	kWh	105,061,675	208,279,694	313,341,369	\$0.08444	\$0.07863	\$0.10833	\$0.10088	\$ 25,248,440	\$ 32,392,587	\$ 7,144,147	
5	Energy Tier 2	kWh	18,332,063	78,623,028	96,955,091	\$0.08444	\$0.07173	\$0.10833	\$0.09202	\$ 7,187,589	\$ 9,220,803	\$ 2,033,214	
6	Water Heating Control Credit 14.01 (Rate 192)	Bills			2,247	-\$4.00	-\$4.00	-\$8.00	-\$8.00	\$ (8,988)	\$ (17,976)	\$ (8,988)	
7	Air Conditioning Control Rider 14.08 (Rate 760)	Bills			1,257	-\$7.00	-\$7.00	-\$8.25	-\$8.25	\$ (8,799)	\$ (10,370)	\$ (1,571)	
8	TailWinds Program 14.09	kWh			3,448	\$1.30	\$1.30	\$3.73	\$3.73	\$ 4,482	\$ 12,870	\$ 8,388	
9	WAPA Bill Credit 14.10									\$ (34,852)	\$ (34,852)	\$ -	
10	Total Base Revenue:									\$ 36,601,009	\$ 46,223,448	\$ 9,622,439	
11	Adjustments for Riders included in Base Rates					Present	Proposed						
12	Economic Development Adjustment	kWh			410,296,460	-\$0.00030	\$0.00000			\$ (122,350)	\$ -		
13	Environmental Cost Recovery Rider Adjustment	\$			\$36,601,009.21	6.49%	0.00%			\$ 2,376,043	\$ -		
14	Renewable Resource Adjustment	kWh			410,296,460	\$0.00511	\$0.00000			\$ 2,096,228	\$ -		
15	Transmission Rider Adjustment	kWh			410,296,460	\$0.00552	\$0.00194			\$ 2,263,447	\$ 796,927		
16	COE Adjustment	kWh			410,296,460	-\$0.00321	\$0.02482			\$ (1,316,326)	\$ 10,184,284		
17	Total Adjustments:									\$ 5,297,042	\$ 10,981,211	\$ 5,684,169	
18													
19	9.02 Residential Demand Control (Rate 241)												
20	Customer Charge	Bills			41,515	\$18.38	\$18.38	\$20.10	\$20.10	\$ 763,051	\$ 834,458	\$ 71,406	
21	Facilities Charge	Bills			41,515	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
22	Energy - All kWh	kWh	15,859,624	68,238,179	84,097,803	\$0.04627	\$0.04671	\$0.06308	\$0.06368	\$ 3,921,230	\$ 5,345,832	\$ 1,424,602	
23	All kW	kW	57,636	115,897	173,533	\$6.52	\$2.63	\$7.31	\$2.95	\$ 680,598	\$ 763,215	\$ 82,617	
24	Total Base Revenue:									\$ 5,364,879	\$ 6,943,505	\$ 1,578,626	
25	Adjustments for Riders included in Base Rates					Present	Proposed						
26	Economic Development Adjustment	kWh			84,097,803	-\$0.00030	\$0.00000			\$ (25,078)	\$ -		
27	Environmental Cost Recovery Rider Adjustment	\$			\$5,364,879.17	6.49%	0.00%			\$ 348,274	\$ -		
28	Renewable Resource Adjustment	kWh			84,097,803	\$0.00511	\$0.00000			\$ 429,661	\$ -		
29	Transmission Rider Adjustment	kWh			84,097,803	\$0.00552	\$0.00194			\$ 463,935	\$ 163,345		
30	COE Adjustment	kWh			84,097,803	-\$0.00321	\$0.02482			\$ (269,805)	\$ 2,087,456		
31	Total Adjustments:									\$ 946,987	\$ 2,250,801	\$ 1,303,814	
32													
33	Total Base Revenue for the COSS Class:									\$ 41,965,888	\$ 53,166,953	\$ 11,201,065	
34	Total Adjustments for the COSS Class:									\$ 6,244,028	\$ 13,232,012	\$ 6,987,983	
35	Total for the COSS Class:									\$ 48,209,916	\$ 66,398,965	\$ 18,189,048	37.73%
36													
37	9.03 Farm Service (Rate 361)												
38	Customer Charge	Bills			13,378	\$12.00	\$12.00	\$13.27	\$13.27	\$ 160,541	\$ 177,532	\$ 16,991	
39	Energy - First 1600 kWh	kWh	3,269,529	6,977,834	10,247,363	\$0.07642	\$0.06971	\$0.10691	\$0.09753	\$ 736,282	\$ 1,030,093	\$ 293,811	
40	Energy - Excess kWh	kWh	4,115,927	16,364,057	20,479,984	\$0.06495	\$0.05925	\$0.09087	\$0.08289	\$ 1,236,900	\$ 1,730,431	\$ 493,531	
41	Single Phase Facilities Charge	Bills			9,720	\$0.00	\$0.00	\$13.27	\$13.27	\$ -	\$ -	\$ -	
42	All Three Phase Facilities	Bills			3,658			\$0.00	\$0.00	\$ 21,705	\$ 21,563	\$ (142)	
43	Overhead =< 25kVa	Bills			1,731	\$3.37	\$3.37						
44	Overhead > 25kVa	Bills			488	\$3.93	\$3.93						
45	Underground =< 25kVa	Bills			1,220	\$9.39	\$9.39						
46	Underground > 25kVa	Bills			218	\$10.78	\$10.78						
47	Water Heating Control Credit 14.01 (Rate 192)	Bills			12	-\$4.00	-\$4.00	-\$8.00	-\$8.00	\$ (48)	\$ (96)	\$ (48)	
48	Air Conditioning Control Rider 14.08 (Rate 760)	Bills			11	-\$7.00	-\$7.00	-\$8.25	-\$8.25	\$ (77)	\$ (91)	\$ (14)	
49													
50	Total Base Revenue:									\$ 2,155,303	\$ 2,959,433	\$ 804,130	
51	Adjustments for Riders included in Base Rates					Present	Proposed						

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter				
52	Economic Development Adjustment	kWh			30,727,347	-\$0.00025	\$0.00000			\$ (7,572)	\$ -	\$ 7,572	
53	Environmental Cost Recovery Rider Adjustment	%			2,155,303	6.49%	0.00%			\$ 139,920	\$ -	\$ (139,920)	
54	Renewable Resource Adjustment	kWh			30,727,347	\$0.00511	\$0.00000			\$ 156,914	\$ -	\$ (156,914)	
55	Transmission Rider Adjustment	kWh			30,727,347	\$0.00850	\$0.00299			\$ 261,286	\$ 91,995	\$ (169,291)	
56	COE Adjustment	kWh			30,727,347	-\$0.00303	\$0.02500			\$ (93,163)	\$ 768,125		
57	Total Adjustments:									\$ 457,384	\$ 860,120	\$ 402,735	
58													
59	Total Base Revenue for the COSS Class:									\$ 2,155,303	\$ 2,959,433	\$ 804,130	
60	Total Adjustments for the COSS Class:									\$ 457,384	\$ 860,120	\$ 402,736	
61	Total for the COSS Class:									\$ 2,612,687	\$ 3,819,552	\$ 1,206,865	46.19%
62													
63													
64	10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)												
65	Customer Charge	Bills			109,530	\$13.00	\$13.00	\$14.38	\$14.38	\$ 1,423,887	\$ 1,575,038	\$ 151,151	
66	Energy	kWh	26,415,240	60,891,902	87,307,142	\$0.08509	\$0.07762	\$0.10938	\$0.09977	\$ 6,974,102	\$ 8,964,484	\$ 1,990,382	
67	Water Heating Control Credit 14.01 (Rate 192)	Bills			178	-\$4.00	-\$4.00	-\$8.00	-\$8.00	\$ (712)	\$ (1,424)	\$ (712)	
68	WAPA Bill Credit 14.10				-	\$0.00	\$0.00	\$0.00	\$0.00	\$ (22,280)	\$ (22,248)	\$ 32	
69	TailWinds Program 14.09				779	\$1.30	\$1.30	\$3.73	\$3.73	\$ 1,013	\$ 2,908	\$ 1,895	
70													
71	Total Base Revenue:									\$ 8,376,010	\$ 10,518,757	\$ 2,142,747	
72	Adjustments for Riders included in Base Rates					Present	Proposed						
73	Economic Development Adjustment	kWh			87,307,142	-\$0.00030	\$0.00000			\$ (25,957)	\$ -	\$ 25,957	
74	Environmental Cost Recovery Rider Adjustment	%			8,376,010	6.49%	0.00%			\$ 543,749	\$ -	\$ (543,749)	
75	Renewable Resource Adjustment	kWh			87,307,142	\$0.00511	\$0.00000			\$ 446,050	\$ -	\$ (446,050)	
76	Transmission Rider Adjustment	kWh			87,307,142	\$0.00534	\$0.00188			\$ 466,218	\$ 164,149	\$ (302,070)	
77	COE Adjustment	kWh			87,307,142	-\$0.00321	\$0.02482			\$ (280,161)	\$ 2,167,058	\$ 2,447,219	
78	Total Adjustments:									\$ 1,149,899	\$ 2,331,207	\$ 1,181,308	
79													
80	10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)												
81	Customer Charge	Bills			8	\$13.00	\$13.00	\$14.38	\$14.38	\$ 106	\$ 117	\$ 11	
82	Seasonal Fixed Charge	Bills	567	4,086	4,653	\$0.08471	\$0.07725	\$0.10959	\$0.09994	\$ 364	\$ 470	\$ 107	
83	Energy	kWh											
84	Total Base Revenue:									\$ 470	\$ 588	\$ 118	
85	Adjustments for Riders included in Base Rates					Present	Proposed						
86	Economic Development Adjustment	kWh			4,653	-\$0.00030	\$0.00000			\$ (1)	\$ -	\$ 1	
87	Environmental Cost Recovery Rider Adjustment	%			470	6.49%	0.00%			\$ 30	\$ -	\$ (30)	
88	Renewable Resource Adjustment	kWh			4,653	\$0.00511	\$0.00000			\$ 24	\$ -	\$ (24)	
89	Transmission Rider Adjustment	kWh			4,653	\$0.00534	\$0.00188			\$ 25	\$ 9	\$ (16)	
90	COE Adjustment	kWh			4,653	-\$0.00321	\$0.02482			\$ (15)	\$ 115	\$ 130	
91	Total Adjustments:									\$ 63	\$ 124	\$ 61	
92													
93													
94	10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)												
95	Customer Charge	Bills			35,324	\$12.00	\$12.00	\$13.27	\$13.27	\$ 423,890	\$ 468,752	\$ 44,862	
96	Energy	kWh	89,250,972	223,847,637	313,098,609	\$0.08213	\$0.07492	\$0.10540	\$0.09615	\$ 24,100,711	\$ 30,930,003	\$ 6,829,292	
97	Demand per kW	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
98	Facilities Charge	kW			2,190,307	\$0.52	\$0.52	\$0.52	\$0.52	\$ 1,138,960	\$ 1,138,960	\$ 0	
99	WAPA Bill Credit 14.10	kWh								\$ (148,217)	\$ (148,217)	\$ -	
100													
101	Total Base Revenue:									\$ 25,515,344	\$ 32,389,498	\$ 6,874,154	
102	Adjustments for Riders included in Base Rates					Present	Proposed						
103	Economic Development Adjustment	kWh			313,098,609	-\$0.00030	\$0.00000			\$ (93,085)	\$ -	\$ 93,085	

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter				
104	Environmental Cost Recovery Rider Adjustment	%			25,515,344	6.49%	0.00%			\$ 1,656,389	\$ -	\$ (1,656,389)	
105	Renewable Resource Adjustment	kWh			313,098,609	\$0.00511	\$0.00000			\$ 1,599,612	\$ -	\$ (1,599,612)	
106	Transmission Rider Adjustment	kWh			313,098,609	\$0.00534	\$0.00188			\$ 1,671,941	\$ 588,666	\$ (1,083,275)	
107	COE Adjustment	kWh			313,098,609	-\$0.00321	\$0.02482			\$ (1,004,706)	\$ 7,771,448	\$ 8,776,154	
108	Total Adjustments:									\$ 3,830,150	\$ 8,360,114	\$ 4,529,964	
109													
110	10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)												
111	Customer Charge	Bills			40	\$12.00	\$12.00	\$13.27	\$13.27	\$ 483	\$ 535	\$ 51	
112	Energy	kWh	244,376	514,386	758,762	\$0.08176	\$0.07456	\$0.10439	\$0.09520	\$ 58,333	\$ 74,480	\$ 16,147	
113	Demand per kW	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
114	Facilities Charge	kW			2,737	\$0.38	\$0.38	\$0.38	\$0.38	\$ 1,040	\$ 1,040	\$ 0	
115	Total Base Revenue:									\$ 59,856	\$ 76,054	\$ 16,198	
116	Adjustments for Riders included in Base Rates					Present	Proposed						
117	Economic Development Adjustment	kWh			758,762	-\$0.00030	\$0.00000			\$ (226)	\$ -	\$ 226	
118	Environmental Cost Recovery Rider Adjustment	%			59,856	6.49%	0.00%			\$ 3,886	\$ -	\$ (3,886)	
119	Renewable Resource Adjustment	kWh			758,762	\$0.00511	\$0.00000			\$ 3,876	\$ -	\$ (3,876)	
120	Transmission Rider Adjustment	kWh			758,762	\$0.00534	\$0.00188			\$ 4,052	\$ 1,427	\$ (2,625)	
121	COE Adjustment	kWh			758,762	-\$0.00321	\$0.02482			\$ (2,435)	\$ 18,833	\$ 21,268	
122	Total Adjustments:									\$ 9,154	\$ 20,260	\$ 11,106	
123													
124	10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)												
125	Customer Charge	Bills			12	\$16.00	\$16.00	\$17.70	\$17.70	\$ 192	\$ 212	\$ 20	
126	Energy - Declared-Peak	kWh	286	321	607	\$0.20663	\$0.13679	\$0.27200	\$0.18006	\$ 270	\$ 271	\$ 1	
127	Energy - Intermediate	kWh	25,318	41,592	66,910	\$0.07004	\$0.07098	\$0.09220	\$0.09343	\$ 4,683	\$ 6,220	\$ 1,537	
128	Energy - Off-Peak	kWh	18,078	29,986	48,064	\$0.04149	\$0.04295	\$0.05462	\$0.05654	\$ 2,038	\$ 2,683	\$ 645	
129	Demand per kW - Declared-Peak	kW	-	-	-	N/A	N/A	N/A	N/A	\$ -	\$ -	\$ -	
130	Demand per kW - Intermediate	kW	88	181	269	\$2.51	\$2.90	\$2.82	\$3.26	\$ 733	\$ 1,387	\$ 655	
131	Demand per kW - Off-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
132	Facilities Charge	kW		793	793	\$0.52	\$0.52	\$0.52	\$0.52	\$ 412	\$ 412	\$ -	
133													
134	Total Base Revenue:									\$ 8,328	\$ 11,186	\$ 2,858	
135	Adjustments for Riders included in Base Rates					Present	Proposed						
136	Economic Development Adjustment	kWh			115,581	-\$0.00030	\$0.00000			\$ (34)	\$ -	\$ 34	
137	Environmental Cost Recovery Rider Adjustment	%			8,328	6.49%	0.00%			\$ 541	\$ -	\$ (541)	
138	Renewable Resource Adjustment	kWh			115,581	\$0.00511	\$0.00000			\$ 590	\$ -	\$ (590)	
139	Transmission Rider Adjustment	kWh			115,581	\$0.00534	\$0.00188			\$ 617	\$ 217	\$ (400)	
140	COE Adjustment	kWh			115,581	-\$0.00321	\$0.02482			\$ (371)	\$ 2,869	\$ 3,240	
141	Total Adjustments:									\$ 1,343	\$ 3,086	\$ 1,743	
142													
143	Total Base Revenue for the COSS Class:									\$ 33,960,007	\$ 42,996,082	\$ 9,036,075	
144	Total Adjustments for the COSS Class:									\$ 4,990,608	\$ 10,714,791	\$ 5,724,182	
145	Total for the COSS Class:									\$ 38,950,615	\$ 53,710,873	\$ 14,760,258	37.89%
146													
147													
148	10.04 Large General Service - Secondary Service (Rate 603)												
149	Customer Charge	Bills			3,272	\$40.00	\$40.00	\$44.25	\$44.25	\$ 130,873	\$ 144,778	\$ 13,905	
150	Energy - First 700,000 kWh (changing to All kWh)	kWh	96,654,016	190,461,494	287,115,510	\$0.05115	\$0.05165	\$0.06722	\$0.06788	\$ 14,781,189	\$ 19,426,312	\$ 4,645,123	
151	Energy - Excess kWh	kWh	49,275,147	87,533,453	136,808,600	\$0.04715	\$0.04761	\$0.06197	\$0.06257	\$ 6,490,791	\$ 8,530,581	\$ 2,039,790	
152	Demand per kW	kW	322,537	623,784	946,321	\$7.29	\$5.61	\$8.16	\$6.28	\$ 5,850,722	\$ 6,550,635	\$ 699,912	
153	Facilities Charge <1,000 kW	kW	212,293	414,007	626,300	\$0.30	\$0.30	\$0.30	\$0.30	\$ 187,890	\$ 187,890	\$ 0	
154	Facilities Charge >=1,000 kW	kW	165,998	340,526	506,524	\$0.15	\$0.15	\$0.15	\$0.15	\$ 75,979	\$ 75,979	\$ (0)	
155	TailWinds Program 14.09	kWh			240	\$1.30	\$1.30	\$3.73	\$3.73	\$ 312	\$ 896	\$ 584	

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual	Annual	Annual
156													
157	Total Base Revenue:									\$ 27,517,756	\$ 34,917,071	\$ 7,399,315	
158	Adjustments for Riders included in Base Rates					Present	Proposed						
159	Economic Development Adjustment	kWh			423,924,110	-\$0.00022	\$0.00000			\$ (92,456)	\$ -	\$ 92,456	
160	Environmental Cost Recovery Rider Adjustment	%			27,517,756	6.49%	0.00%			\$ 1,786,385	\$ -	\$ (1,786,385)	
161	Renewable Resource Adjustment	kWh			423,924,110	\$0.00510	\$0.00000			\$ 2,163,720	\$ -	\$ (2,163,720)	
162	Transmission Rider Adjustment	kWh			423,924,110	\$0.00407	\$0.00143			\$ 1,725,640	\$ 607,573	\$ (1,118,067)	
163	COE Adjustment	kWh			423,924,110	-\$0.00340	\$0.02463			\$ (1,443,142)	\$ 10,439,450	\$ 11,882,593	
164	Total Adjustments:									\$ 4,140,146	\$ 11,047,023	\$ 6,906,877	
165	10.04 Large General Service - Primary Service (Rate 602)												
166	Customer Charge	Bills			113	\$40.00	\$40.00	\$44.25	\$44.25	\$ 4,538	\$ 5,020	\$ 482	
167	Energy - First 700,000 kWh (changing to All kWh)	kWh	11,345,397	21,942,716	33,288,113	\$0.05095	\$0.05141	\$0.06723	\$0.06784	\$ 1,706,123	\$ 2,251,305	\$ 545,182	
168	Energy - Excess kWh	kWh	36,328,042	72,321,568	108,649,610	\$0.04695	\$0.04737	\$0.06195	\$0.06251	\$ 5,131,474	\$ 6,771,208	\$ 1,639,734	
169	Demand per kW	kW	97,630	184,354	281,984	\$7.24	\$5.57	\$8.10	\$6.23	\$ 1,733,693	\$ 1,939,108	\$ 205,415	
170	Facilities Charge - All kW	kW	85,885	171,505	257,390	\$0.11	\$0.11	\$0.11	\$0.11	\$ 3,386	\$ 3,386	\$ -	
171	Total Base Revenue:									\$ 8,579,214	\$ 10,970,027	\$ 2,390,813	
172	Adjustments for Riders included in Base Rates					Present	Proposed						
173	Economic Development Adjustment	kWh			141,937,723	-\$0.00022	\$0.00000			\$ (30,956)	\$ -	\$ 30,956	
174	Environmental Cost Recovery Rider Adjustment	%			8,579,214	6.49%	0.00%			\$ 556,941	\$ -	\$ (556,941)	
175	Renewable Resource Adjustment	kWh			141,937,723	\$0.00510	\$0.00000			\$ 724,454	\$ -	\$ (724,454)	
176	Transmission Rider Adjustment	kWh			141,937,723	\$0.00407	\$0.00143			\$ 577,777	\$ 203,427	\$ (374,350)	
177	COE Adjustment	kWh			141,937,723	-\$0.00340	\$0.02463			\$ (483,191)	\$ 3,495,323	\$ 3,978,514	
178	Total Adjustments:									\$ 1,345,025	\$ 3,698,750	\$ 2,353,725	
179													
180	14.02 Real Time Pricing - Primary Service (Rate 662)												
181	Customer Charge	Bills			12	\$199.00	\$199.00	\$220.13	\$220.13	\$ 2,494	\$ 2,642	\$ 148	
182	Energy - All kWh	kWh	-	-	35,803,845	Real Time Pricing	Real Time Pricing			\$ -	\$ -	\$ -	
183	Total Base Revenue:									\$ 1,245,401	\$ 1,594,283	\$ 348,882	
184	Adjustments for Riders included in Base Rates					Present	Proposed						
185	Economic Development Adjustment	kWh			35,803,845	-\$0.00022	\$0.00000			\$ (7,806)	\$ -	\$ 7,806	
186	Environmental Cost Recovery Rider Adjustment	%			1,245,401	6.49%	0.00%			\$ 80,848	\$ -	\$ (80,848)	
187	Renewable Resource Adjustment	kWh			35,803,845	\$0.00510	\$0.00000			\$ 182,744	\$ -	\$ (182,744)	
188	Transmission Rider Adjustment	kWh			35,803,845	\$0.00407	\$0.00143			\$ 145,744	\$ 51,314	\$ (94,430)	
189	COE Adjustment	kWh			35,803,845	-\$0.00340	\$0.02463			\$ (121,885)	\$ 881,697	\$ 1,003,582	
190	Total Adjustments:									\$ 279,645	\$ 933,011	\$ 653,366	
191													
192	10.04 Large General Service - Transmission Service (Rate 632)												
193	Customer Charge	Bills			-	\$40.00	\$40.00	\$282.00	\$282.00	\$ -	\$ -	\$ -	
194	Energy - First 700,000 kWh (changing to All kWh)	kWh			-	\$0.04974	\$0.04996	\$0.02920	\$0.02945	\$ -	\$ -	\$ -	

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
208	Customer Charge	Bills			12	\$60.00	\$60.00	\$66.37	\$66.37	\$ 720	\$ 796	\$ 76	
209	Facilities Charge <1,000 kW	kW			4,242	\$0.30	\$0.30	\$0.30	\$0.30	\$ 1,273	\$ 1,273	\$ (0)	
210	Facilities Charge >=1,000 kW	kW			-	\$0.15	\$0.15	\$0.15	\$0.15	\$ -	\$ -	\$ -	
211	Energy - On-Peak	kWh	11,459	18,816	30,275	\$0.08150	\$0.07314	\$0.10714	\$0.09615	\$ 8,238	\$ 3,037	\$ (5,201)	
212	Energy - Shoulder	kWh	18,847	106,291	125,138	\$0.06247	\$0.05949	\$0.08213	\$0.07821	\$ 7,188	\$ 9,861	\$ 2,672	
213	Energy - Off-Peak	kWh	21,318	278,163	299,481	\$0.03721	\$0.04199	\$0.04892	\$0.05520	\$ 9,331	\$ 16,398	\$ 7,067	
214	Demand per kW - On-Peak	kW	320	908	1,228	\$5.75	\$4.42	\$6.46	\$4.97	\$ 5,244	\$ 6,576	\$ 1,331	
215	Demand per kW - Shoulder	kW	320	1,361	1,681	\$1.59	\$1.22	\$1.79	\$1.37	\$ 2,029	\$ 2,437	\$ 407	
216	Demand per kW - Off-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
217	Total Base Revenue:									\$ 34,024	\$ 40,378	\$ 6,354	
218	<i>Adjustments for Riders included in Base Rates</i>												
219	Economic Development Adjustment	kWh			454,894	Present -\$0.00022	Proposed \$0.00000			\$ (99)	\$ -	\$ 99	
220	Environmental Cost Recovery Rider Adjustment	%			34,024	6.49%	0.00%			\$ 2,209	\$ -	\$ (2,209)	
221	Renewable Resource Adjustment	kWh			454,894	\$0.00510	\$0.00000			\$ 2,322	\$ -	\$ (2,322)	
222	Transmission Rider Adjustment	kW			454,894	\$0.00407	\$0.00143			\$ 1,852	\$ 652	\$ (1,200)	
223	COE Adjustment	kWh			454,894	-\$0.00340	\$0.02463			\$ (1,549)	\$ 11,202	\$ 12,751	
224	Total Adjustments:									\$ 4,734	\$ 11,854	\$ 7,120	
225													
226	10.05 Large General Service Time of Day - Primary Service (Rates 610, 614, 612)												
227	Customer Charge	Bills			-	\$60.00	\$60.00	\$66.37	\$66.37	\$ -	\$ -	\$ -	
228	Facilities Charge - All kW	kW			-	\$0.11	\$0.11	\$0.11	\$0.11	\$ -	\$ -	\$ -	
229	Energy - On-Peak	kWh	-	-	-	\$0.08115	\$0.07278	\$0.10668	\$0.09568	\$ -	\$ -	\$ -	
230	Energy - Shoulder	kWh	-	-	-	\$0.06221	\$0.05921	\$0.08178	\$0.07784	\$ -	\$ -	\$ -	
231	Energy - Off-Peak	kWh	-	-	-	\$0.03709	\$0.04184	\$0.04876	\$0.05500	\$ -	\$ -	\$ -	
232	Demand per kW - On-Peak	kW	-	-	-	\$5.71	\$4.39	\$6.41	\$4.93	\$ -	\$ -	\$ -	
233	Demand per kW - Shoulder	kW	-	-	-	\$1.57	\$1.21	\$1.76	\$1.36	\$ -	\$ -	\$ -	
234	Demand per kW - Off-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
235	Total Base Revenue:									\$ -	\$ -	\$ -	
236	<i>Adjustments for Riders included in Base Rates</i>												
237	Economic Development Adjustment	kWh			-	Present -\$0.00022	Proposed \$0.00000			\$ -	\$ -	\$ -	
238	Environmental Cost Recovery Rider Adjustment	%			-	6.49%	0.00%			\$ -	\$ -	\$ -	
239	Renewable Resource Adjustment	kWh			-	\$0.00510	\$0.00000			\$ -	\$ -	\$ -	
240	Transmission Rider Adjustment	kW			-	\$0.00407	\$0.00143			\$ -	\$ -	\$ -	
241	COE Adjustment	kWh			-	-\$0.00340	\$0.02463			\$ -	\$ -	\$ -	
242	Total Adjustments:									\$ -	\$ -	\$ -	
243													
244	10.05 Large General Service Time of Day - Transmission Service (Rates 639, 637, 640)												
245	Customer Charge	Bills			-	\$60.00	\$60.00	\$66.37	\$66.37	\$ -	\$ -	\$ -	
246	Facilities Charge	kW			-	N/A	N/A	N/A	N/A	\$ -	\$ -	\$ -	
247	Energy - On-Peak	kWh	-	-	-	\$0.07900	\$0.07063	\$0.10386	\$0.09285	\$ -	\$ -	\$ -	
248	Energy - Shoulder	kWh	-	-	-	\$0.06066	\$0.05752	\$0.07975	\$0.07562	\$ -	\$ -	\$ -	
249	Energy - Off-Peak	kWh	-	-	-	\$0.03635	\$0.04070	\$0.04779	\$0.05351	\$ -	\$ -	\$ -	
250	Demand per kW - On-Peak	kW	-	-	-	\$4.86	\$3.74	\$5.46	\$4.20	\$ -	\$ -	\$ -	
251	Demand per kW - Shoulder	kW	-	-	-	\$1.06	\$0.82	\$1.19	\$0.92	\$ -	\$ -	\$ -	
252	Demand per kW - Off-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
253	Total Base Revenue:									\$ -	\$ -	\$ -	
254	<i>Adjustments for Riders included in Base Rates</i>												
255	Economic Development Adjustment	kWh			140,646	Present -\$0.00022	Proposed \$0.00000			\$ (33)	\$ -	\$ 33	
256	Environmental Cost Recovery Rider Adjustment	%			13,134	6.49%	0.00%			\$ 853	\$ -	\$ (853)	
257	Renewable Resource Adjustment	kWh			140,646	\$0.00510	\$0.00000			\$ 718	\$ -	\$ (718)	
258	Transmission Rider Adjustment	kWh			140,646	\$0.00407	\$0.00143			\$ 573	\$ 202	\$ (371)	
259	COE Adjustment	kWh			140,646	-\$0.00340	\$0.02463			\$ (479)	\$ 3,464	\$ 3,943	

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase	Pct Inc.			
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual	Annual	Annual			
260	Total Adjustments:									\$	1,631	\$	3,665	\$	2,034	
261																
262	Total Base Revenue for the COSS Class:									\$	37,389,529	\$	47,537,638	\$	10,145,364	
263	Total Adjustments for the COSS Class:									\$	5,771,181	\$	15,694,304	\$	9,923,123	
264	Total for the COSS Class:									\$	43,160,710	\$	63,231,942	\$	20,071,232	46.50%
265																
266																
267	11.01 Standby Service - Option A: Firm - Secondary Service (Rates 947, 948, 949)															
268	Customer Charge	Bills			-	\$199.00	\$199.00	\$220.13	\$220.13							
269	Facilities Charge per month per kW of Contracted Backup	kW			-	\$0.30	\$0.30	\$0.30	\$0.30							
270	Reservation Charge per kW of Contracted Backup	kW			-	\$0.85069	\$0.09697	\$0.96481	\$0.10998							
271	Metered Demand per day per kW On-Peak Backup	kW			-	\$0.49076	\$0.32187	\$0.55660	\$0.36505							
272	Energy - On-Peak	kWh			-	\$0.08150	\$0.07314	\$0.09159	\$0.08220							
273	Energy - Shoulder	kWh			-	\$0.06247	\$0.05949	\$0.07020	\$0.06686							
274	Energy - Off-Peak	kWh			-	\$0.03721	\$0.04199	\$0.04182	\$0.04719							
275																
276	Total:															
277	11.01 Standby Service - Option A: Firm - Primary Service (Rates 944, 945, 946)															
278	Customer Charge	Bills			-	\$199.00	\$199.00	\$220.13	\$220.13							
279	Facilities Charge per month per kW of Backup	kW			-	\$0.11	\$0.11	\$0.11	\$0.11							
280	Reservation Charge per kW of Contracted Backup	kW			-	\$0.84590	\$0.09634	\$0.95938	\$0.10926							
281	Metered Demand per day per kW On-Peak Backup	kW			-	\$0.48683	\$0.31978	\$0.55214	\$0.36268							
282	Energy - On-Peak	kWh			-	\$0.08115	\$0.07278	\$0.09120	\$0.08179							
283	Energy - Shoulder	kWh			-	\$0.06221	\$0.05921	\$0.06991	\$0.06654							
284	Energy - Off-Peak	kWh			-	\$0.03709	\$0.04181	\$0.04168	\$0.04699							
285	Conservation Improvement Program				-											
286	Total:															
287	11.01 Standby Service - Option A: Firm - Transmission Service (Rates 941, 942, 943)															
288	Customer Charge	Bills			12	\$199.00	\$199.00	\$220.13	\$220.13	\$ 2,388	\$	2,642	\$	254		
289	Facilities Charge per month per kW of Backup	kW	3,755	5,781	9,536	N/A	N/A	N/A	N/A			\$	-			
290	Reservation Charge per kW of Contracted Backup	kW	3,755	5,781	9,536	\$0.81704	\$0.09254	\$0.92665	\$0.10495	\$ 3,603	\$	4,086	\$	483		
291	Metered Demand per day per kW On-Peak Backup	kW			-	\$0.35865	\$0.28694	\$0.40676	\$0.32543	\$ -	\$	-	\$	-		
292	Energy - On-Peak	kWh	11,771	24,871	36,642	\$0.07900	\$0.07063	\$0.07938	\$0.08920	\$ 2,687	\$	3,153	\$	466		
293	Energy - Shoulder	kWh	20,689	23,640	44,329	\$0.06066	\$0.05752	\$0.06464	\$0.07265	\$ 2,615	\$	3,055	\$	440		
294	Energy - Off-Peak	kWh	21,888	37,787	59,675	\$0.03635	\$0.04070	\$0.04574	\$0.05140	\$ 2,334	\$	2,943	\$	610		
295	Conservation Improvement Program				-											
296	Total:									\$	13,134	\$	15,879	\$	2,253	
297	11.01 Standby Service - Option B: Non-Firm - Secondary Service (Rates 956, 957, 958)															
298	Customer Charge	Bills			-	\$199.00	\$199.00	\$220.13	\$220.13							
299	Facilities Charge per month per kW of Backup	kW			-	\$0.30	\$0.30	\$0.30	\$0.30							
300	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A							
301	Energy - Shoulder	kWh			-	\$0.06247	\$0.05949	\$0.07020	\$0.06686							
302	Energy - Off-Peak	kWh			-	\$0.03721	\$0.04199	\$0.04182	\$0.04719							
303	Conservation Improvement Program				-											
304	Total:															
305	11.01 Standby Service - Option B: Non-Firm - Primary Service (Rates 953, 954, 955)															
306	Customer Charge	Bills			-	\$199.00	\$199.00	\$220.13	\$220.13							
307	Facilities Charge per month per kW of Backup	kW			-	\$0.11	\$0.11	\$0.11	\$0.11							
308	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A							
309	Energy - Shoulder	kWh			-	\$0.06221	\$0.05921	\$0.06991	\$0.06654							
310	Energy - Off-Peak	kWh			-	\$0.03709	\$0.04181	\$0.04168	\$0.04699							
311	Conservation Improvement Program				-											

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter				
312	Total:												
313	11.01 Standby Service - Option B: Non-Firm - Transmission Service (Rates 950, 951, 952)												
314	Customer Charge	Bills			-	\$199.00	\$199.00	\$220.13	\$220.13				
315	Facilities Charge per month per kW of Backup	kW			-	N/A	N/A	N/A	N/A				
316	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A				
317	Energy - Shoulder	kWh			-	\$0.06066	\$0.05752	\$0.06464	\$0.07265				
318	Energy - Off-Peak	kWh			-	\$0.03635	\$0.04070	\$0.04574	\$0.05140				
319	Conservation Improvement Program				-								
320	Total:												
321													
322													
323	11.02 Irrigation Service - Option 1: Non-Time-of-Use (Rate 703)												
324	Customer Charge	Bills			79	\$1.00	\$1.00	\$1.11	\$1.11	\$ 79	\$ 88	\$ 9	
325	Energy	kWh	272,835	44,562	317,397	\$0.06896	\$0.05145	\$0.08629	\$0.06438	\$ 21,107	\$ 26,411	\$ 5,304	
326	18% Return of Distribution Facilities				-					\$ 5,158	\$ 5,158	\$ -	
327	Total Base Revenue:									\$ 26,344	\$ 31,657	\$ 5,313	
328	Adjustments for Riders included in Base Rates					Present	Proposed						
329	Economic Development Adjustment	kWh			317,397	-\$0.00023	\$0.00000			\$ (73)	\$ -	\$ 73	
330	Environmental Cost Recovery Rider Adjustment	%			26,344	6.49%	0.00%			\$ 1,710	\$ -	\$ (1,710)	
331	Renewable Resource Adjustment	kWh			317,397	\$0.00510	\$0.00000			\$ 1,620	\$ -	\$ (1,620)	
332	Transmission Rider Adjustment	kWh			317,397	\$0.00000	\$0.00000			\$ -	\$ -	\$ -	
333	COE Adjustment	kWh			317,397	-\$0.00520	\$0.02283			\$ (1,651)	\$ 7,245	\$ 8,896	
334	Total Adjustments:									\$ 1,606	\$ 7,245	\$ 5,639	
335													
336	11.02 Irrigation Service - Option 2 (Rates 704, 705, 706)												
337	Customer Charge	Bills			164	\$5.00	\$5.00	\$5.53	\$5.53	\$ 819	\$ 906	\$ 87	
338	Energy - Declared-Peak	kWh	5,043	504	5,547	\$0.14450	\$0.08760	\$0.18005	\$0.10915	\$ 773	\$ 963	\$ 190	
339	Energy - Intermediate	kWh	261,095	24,342	285,437	\$0.05441	\$0.05111	\$0.06780	\$0.06369	\$ 15,450	\$ 19,252	\$ 3,801	
340	Energy - Off-Peak	kWh	231,192	25,683	256,875	\$0.02642	\$0.02612	\$0.03292	\$0.03255	\$ 6,779	\$ 8,447	\$ 1,668	
341	Demand per kW - Declared-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
342	Demand per kW - Intermediate	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
343	Demand per kW - Off-Peak	kW	-	-	-	\$0.00	\$0.00	\$0.00	\$0.00	\$ -	\$ -	\$ -	
344	18% Return of Distribution Facilities				-					\$ 5,196	\$ 5,196	\$ -	
345	Total Base Revenue:									\$ 29,018	\$ 34,764	\$ 5,746	
346	Adjustments for Riders included in Base Rates					Present	Proposed						
347	Economic Development Adjustment	kWh			547,859	-\$0.00023	\$0.00000			\$ (124)	\$ -	\$ 124	
348	Environmental Cost Recovery Rider Adjustment	%			29,018	6.49%	0.00%			\$ 1,884	\$ -	\$ (1,884)	
349	Renewable Resource Adjustment	kWh			547,859	\$0.00510	\$0.00000			\$ 2,796	\$ -	\$ (2,796)	
350	Transmission Rider Adjustment	kWh			547,859	\$0.00000	\$0.00000			\$ -	\$ -	\$ -	
351	COE Adjustment	kWh			547,859	-\$0.00520	\$0.02283			\$ (2,851)	\$ 12,505	\$ 15,356	
352	Total Adjustments:									\$ 1,705	\$ 12,505	\$ 10,800	
353													
354	Total Base Revenue for the COSS Class:									\$ 55,362	\$ 66,420	\$ 11,058	
355	Total Adjustments for the COSS Class:									\$ 3,311	\$ 19,750	\$ 16,439	
356	Total for the COSS Class:									\$ 58,673	\$ 86,170	\$ 27,497	46.87%
357													
358													
359	11.03 Outdoor Lighting - Metered - Energy Only (Rate 748)												
360	Customer Charge	Bills			1,140	\$2.00	\$2.00	\$2.00	\$2.00	\$ 2,281	\$ 2,281	\$ (0)	
361	Energy	kWh			1,220,905	\$0.06978	\$0.06978	\$0.08977	\$0.08977	\$ 84,559	\$ 109,600	\$ 25,041	
362	Total Base Revenue:									\$ 86,839	\$ 111,880	\$ 25,041	
363	Adjustments for Riders included in Base Rates					Present	Proposed						

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
364	Economic Development Adjustment	kWh			1,220,905	-\$0.00040	\$0.00000			\$ (484)	\$ -	\$ 484	
365	Environmental Cost Recovery Rider Adjustment	%			86,839	6.49%	0.00%			\$ 5,637	\$ -	\$ (5,637)	
366	Renewable Resource Adjustment	kWh			1,220,905	\$0.00511	\$0.00000			\$ 6,244	\$ -	\$ (6,244)	
367	Transmission Rider Adjustment	kWh			1,220,905	\$0.00306	\$0.00108			\$ 3,735	\$ 1,315	\$ (2,420)	
368	COE Adjustment	kWh			1,220,905	-\$0.00333	\$0.02470			\$ (4,060)	\$ 30,162	\$ 34,222	
369	Total Adjustments:									\$ 11,073	\$ 31,477	\$ 20,404	
370				128,357									
371	11.03 Outdoor Lighting - Non-Metered - Energy Only (Rate 749)												
372		kWh			2,533,051	\$0.00	\$0.00	\$0.00	\$0.00				
373	Monthly charge for connected KW	kW			618	\$ 23.84	\$ 23.84	\$30.39	\$30.39	\$ 177,817	\$ 225,338	\$ 47,522	
374	Total Base Revenue:									\$ 177,817	\$ 225,338	\$ 47,522	
375													
376	Non Standard Ligting	kwh			793,280	\$0.06978	\$0.06978	\$0.08977	\$0.08977	\$ 41,518	\$ 71,212	\$ 29,694	
377													
378	Adjustments for Riders included in Base Rates					Present	Proposed						
379	Economic Development Adjustment	kWh			3,326,331	-\$0.00040	\$0.00000			\$ (1,318)	\$ -	\$ 1,318	
380	Environmental Cost Recovery Rider Adjustment	%			219,335	6.49%	0.00%			\$ 14,238	\$ -	\$ (14,238)	
381	Renewable Resource Adjustment	kWh			3,326,331	\$0.00511	\$0.00000			\$ 17,012	\$ -	\$ (17,012)	
382	Transmission Rider Adjustment	kWh			3,326,331	\$0.00306	\$0.00108			\$ 10,177	\$ 3,583	\$ (6,594)	
383	COE Adjustment	kWh			3,326,331	-\$0.00333	\$0.02470			\$ (11,061)	\$ 82,175	\$ 93,236	
384	Total Adjustments:									\$ 29,048	\$ 85,758	\$ 56,710	
385													
386	11.03 Sign Lighting (Rate 744)												
387	Monthly charge for connected KW	kW			119	\$23.84	\$23.84	\$30.45	\$30.45	\$ 33,148	\$ 43,654	\$ 10,505	
388	Energy	kWh			489,810					\$ -	\$ -	\$ -	
389	Total Base Revenue:									\$ 33,148	\$ 43,654	\$ 10,505	
390	Adjustments for Riders included in Base Rates					Present	Proposed						
391	Economic Development Adjustment	kWh			489,810	-\$0.00040	\$0.00000			\$ (194)	\$ -	\$ 194	
392	Environmental Cost Recovery Rider Adjustment	%			33,148	6.49%	0.00%			\$ 2,152	\$ -	\$ (2,152)	
393	Renewable Resource Adjustment	kWh			489,810	\$0.00511	\$0.00000			\$ 2,505	\$ -	\$ (2,505)	
394	Transmission Rider Adjustment	kWh			489,810	\$0.00306	\$0.00108			\$ 1,499	\$ 528	\$ (971)	
395	COE Adjustment	kWh			489,810	-\$0.00333	\$0.02470			\$ (1,629)	\$ 12,100	\$ 13,729	
396	Total Adjustments:									\$ 4,332	\$ 12,628	\$ 8,296	
397													
398	11.04 Outdoor Lighting - Street & Area Lighting (Rate 741)									\$ 339,322.31	\$ 452,084.56		
399	Type:		kWh/lit	Annual Kwh	Quantity								
400	MV-6	Lts	70	7,286,717	104,096	\$7.01	\$7.01	\$ 8.74	\$8.74	\$	909,318		
401	MV-6PT	Lts	70	151,859	2,169	\$10.00	\$10.00	\$ 12.46	\$12.46	\$	27,034		
402	MV-11	Lts	100	9,639	96	\$12.70	\$12.70	\$ 15.83	\$15.83	\$	1,525		
403	MV-21	Lts	154	70,849	460	\$16.72	\$16.72	\$ 20.84	\$20.84	\$	9,585		
404	MV-35	Lts	260	-	-	\$24.53	\$24.53	\$ 30.57	\$30.57	\$	-		
405	MV-55	Lts	366	-	-	\$31.36	\$31.36	\$ 39.08	\$39.08	\$	-		
406	MA-8	Lts	41	192,525	4,696	\$8.46	\$8.46	\$ 10.54	\$10.54	\$	49,504		
407	MA-14	Lts	70	842	12	\$16.10	\$16.10	\$ 20.06	\$20.06	\$	241		
408	MA-20	Lts	98	-	-	\$18.38	\$18.38	\$ 22.90	\$22.90	\$	-		
409	MA-36	Lts	156	32,557	209	\$18.00	\$18.00	\$ 22.43	\$22.43	\$	4,681		
410	MA-110	Lts	369	132,401	359	\$38.41	\$38.41	\$ 47.86	\$47.86	\$	17,174		
411	HPS-9	Lts	44	3,743,878	85,088	\$7.52	\$7.52	\$ 9.37	\$9.37	\$	797,354		
412	HPS-9PT	Lts	44	144,463	3,283	\$9.72	\$9.72	\$ 12.11	\$12.11	\$	39,768		
413	HPS-14	Lts	64	150,420	2,350	\$11.71	\$11.71	\$ 14.59	\$14.59	\$	34,296		
414	HPS-14PT	Lts	64	36,488	570	\$12.53	\$12.53	\$ 15.61	\$15.61	\$	8,902		
415	HPS-19	Lts	83	87,748	1,057	\$13.61	\$13.61	\$ 16.96	\$16.96	\$	17,930		

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
416	HPS-23	Lts	102	681,430	6,681	\$15.40	\$15.40	\$ 19.19	\$19.19		\$ 128,205		
417	HPS-44	Lts	156	714,834	4,582	\$19.01	\$19.01	\$ 23.69	\$23.69		\$ 108,549		
418	UHPS23	Lts	102	1,289	13	\$17.99	\$17.99	\$ 22.42	\$22.42		\$ 283		
419	UHPS9	Lts	44	2,671	61	\$9.86	\$9.86	\$ 12.29	\$12.29		\$ 746		
420	UMV6	Lts	70	1,815	26	\$8.97	\$8.97	\$ 11.18	\$11.18		\$ 290		
421	Seasonal Charge				92	\$10.80	\$10.80	\$ 13.46	\$13.46		\$ 1,238		
422	Total Base Revenue:			13,442,425						\$ 1,728,486	\$ 2,156,625	\$ 428,138	
423					\$ 18,632	\$25,062.92							
424	MH Lights that were not accounted for in the forecast				\$ (1,728,486)								
425													
426													
427	Adjustments for Riders included in Base Rates					Present	Proposed						
428	Economic Development Adjustment	kWh			13,442,425	-\$0.00040	\$0.00000			\$ (5,325)	\$ -	\$ 5,325	
429	Environmental Cost Recovery Rider Adjustment	%			1,728,486	6.49%	0.00%			\$ 112,207	\$ -	\$ (112,207)	
430	Renewable Resource Adjustment	kWh			13,442,425	\$0.00511	\$0.00000			\$ 68,749	\$ -	\$ (68,749)	
431	Transmission Rider Adjustment	kWh			13,442,425	\$0.00306	\$0.00108			\$ 41,127	\$ 14,480	\$ (26,646)	
432	COE Adjustment	kWh			13,442,425	-\$0.00333	\$0.02470			\$ (44,703)	\$ 332,088	\$ 376,791	
433	Total Adjustments:									\$ 172,054	\$ 346,568	\$ 174,514	
434													
435	11.04 Outdoor Lighting - Flood Lighting (Rate 743)												
436	Type:	kWh/Lt	Annual Kwh	Quantity									
437	400MV-F	Lts	154	306,361	1,989	\$17.35	\$17.35	\$21.68	\$21.68		\$ 43,137		
438	400MA-F	Lts	156	1,082,994	6,942	\$18.49	\$18.49	\$23.11	\$23.11		\$ 160,426		
439	400HPS-F	Lts	156	1,813,773	11,627	\$18.90	\$18.90	\$23.62	\$23.62		\$ 274,636		
440	1000MV-F	Lts	366	1,652,385	4,515	\$30.44	\$30.44	\$38.04	\$38.04		\$ 171,756		
441	1000MA-F	Lts	308	4,623	15	\$32.11	\$32.11	\$40.13	\$40.13		\$ 602		
442	1M-HPSF	Lts	371	4,801	13	\$37.32	\$37.32	\$46.64	\$46.64		\$ 604		
443	U1M-MAF	Lts	371	-	-	\$39.44	\$39.44	\$49.29	\$49.29		\$ -		
444	UNDERGROUND SERVICE:					\$1.96	\$1.96	\$2.45	\$2.45		\$ -		
445													
446	Total Base Revenue:			4,864,937						\$ 530,119	\$ 651,160	\$ 121,041	
447	Adjustments for Riders included in Base Rates					Present	Proposed						
448	Economic Development Adjustment	kWh			4,558,576	-\$0.00040	\$0.00000			\$ (1,806)	\$ -	\$ 1,806	
449	Environmental Cost Recovery Rider Adjustment	%			530,119	6.49%	0.00%			\$ 34,413	\$ -	\$ (34,413)	
450	Renewable Resource Adjustment	kWh			4,558,576	\$0.00511	\$0.00000			\$ 23,313	\$ -	\$ (23,313)	
451	Transmission Rider Adjustment	kWh			4,558,576	\$0.00306	\$0.00108			\$ 13,947	\$ 4,910	\$ (9,036)	
452	COE Adjustment	kWh			4,558,576	-\$0.00333	\$0.02470			\$ (15,160)	\$ 112,617	\$ 127,777	
453	Total Adjustments:									\$ 54,707	\$ 117,528	\$ 62,821	
454													
455	Total Base Revenue for the COSS Class:									\$ 2,597,928	\$ 3,259,870	\$ 661,942	
456	Total Adjustments for the COSS Class:									\$ 271,215	\$ 593,959	\$ 322,744	
457	Total for the COSS Class:									\$ 2,869,143	\$ 3,853,828	\$ 984,685	34.32%
458													
459													
460													
461	11.05 Municipal Pumping - Secondary Service (Rate 872)												
462	Customer Charge	Bills			6,929	\$4.00	\$4.00	\$4.42	\$4.42	\$ 27,716	\$ 30,659	\$ 2,943	
463	Facilities Charge (Changing per Month to per KW)	kW			-	\$4.00	\$4.00	\$4.00	\$4.00				
464	Energy - All kWh	kWh	5,736,571	10,722,486	16,459,057	\$0.06523	\$0.05950	\$0.08562	\$0.07809	\$ 1,012,184	\$ 1,328,509		
465	Total Base Revenue:									\$ 1,039,969	\$ 1,359,168	\$ 319,199	
466	Adjustments for Riders included in Base Rates					Present	Proposed						
467	Economic Development Adjustment	kWh			16,459,057	-\$0.00022	\$0.00000			\$ (3,667)	\$ -	\$ 3,667	

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
468	Environmental Cost Recovery Rider Adjustment	%			1,039,969	6.49%	0.00%			\$ 67,512	\$ -	\$ (67,512)	
469	Renewable Resource Adjustment	kWh			16,459,057	\$0.00510	\$0.00000			\$ 84,012	\$ -	\$ (84,012)	
470	Transmission Rider Adjustment	kWh			16,459,057	\$0.00421	\$0.00148			\$ 69,279	\$ 24,392	\$ (44,887)	
471	COE Adjustment	kWh			16,459,057	-\$0.00347	\$0.02456			\$ (57,088)	\$ 404,259	\$ 461,347	
472	Total Adjustments:									\$ 160,049	\$ 428,652	\$ 268,603	
473													
474	11.05 Municipal Pumping -Primary Service (Rate 874)												
475	Customer Charge	Bills			-	\$4.00	\$4.00	\$4.42	\$4.42				
476	Facilities Charge (Changing per Month to per KW)	KW			-	\$2.68	\$2.68	\$2.68	\$2.68				
477	Energy - All kWh	kWh			-	\$0.06494	\$0.05922	\$0.08523	\$0.07773				
478	Total Base Revenue:									\$ -	\$ -	\$ -	
479													
480	11.06 Civil Defense - Fire Sirens (Rate 843)												
481	Customer Charge	Bills			816	\$1.00	\$1.00	\$1.11	\$1.11	\$ 816	\$ 903	\$ 87	
482	Load Charge	HP			5,658	\$0.53193	\$0.53193	\$0.66459	\$0.66459	\$ 3,010	\$ 3,760		
483	Total Base Revenue:									\$ 3,727	\$ 4,663	\$ 936	
484	Adjustments for Riders included in Base Rates					Present	Proposed						
485	Economic Development Adjustment	kWh			-	-\$0.00022	\$0.00000			\$ -	\$ -	\$ -	
486	Environmental Cost Recovery Rider Adjustment	%			3,727	6.49%	0.00%			\$ 242	\$ -	\$ (242)	
487	Renewable Resource Adjustment	kWh			-	\$0.00510	\$0.00000			\$ -	\$ -	\$ -	
488	Transmission Rider Adjustment	kWh			-	\$0.00421	\$0.00148			\$ -	\$ -	\$ -	
489	COE Adjustment	kWh			-	-\$0.00347	\$0.02456			\$ -	\$ -	\$ -	
490	Total Adjustments:									\$ 242	\$ -	\$ (242)	
491													
492	Total Base Revenue for the COSS Class:									\$ 1,043,696	\$ 1,363,831	\$ 320,135	
493	Total Adjustments for the COSS Class:									\$ 160,291	\$ 428,935	\$ 268,644	
494	Total for the COSS Class:									\$ 1,203,986	\$ 1,792,766	\$ 588,780	48.90%
495													
496													
497	14.01 Water Heating - Controlled Service (Rate 191)												
498	Customer Charge	Bills			68,012	\$1.00	\$1.00	\$1.11	\$1.11	\$ 68,012	\$ 75,234	\$ 7,222	
499	Facilities Charges per Month	Bills			68,012	\$1.00	\$1.00	\$1.00	\$1.00	\$ 68,012	\$ 68,012	\$ (0)	
500	Energy - All kWh	kWh	4,511,887	10,487,484	14,999,371	\$0.05773	\$0.05638	\$0.07359	\$0.07187	\$ 851,756	\$ 1,085,809	\$ 234,053	
501	Total Base Revenue:									\$ 987,779	\$ 1,229,054	\$ 241,275	
502	Adjustments for Riders included in Base Rates					Present	Proposed						
503	Economic Development Adjustment	kWh			14,999,371	-\$0.00023	\$0.00000			\$ (3,470)	\$ -	\$ 3,470	
504	Environmental Cost Recovery Rider Adjustment	%			987,779	6.49%	0.00%			\$ 64,123	\$ -	\$ (64,123)	
505	Renewable Resource Adjustment	kWh			14,999,371	\$0.00510	\$0.00000			\$ 76,559	\$ -	\$ (76,559)	
506	Transmission Rider Adjustment	kWh			14,999,371	\$0.00055	\$0.00019			\$ 8,190	\$ 2,884	\$ (5,307)	
507	COE Adjustment	kWh			14,999,371	-\$0.00321	\$0.02482			\$ (48,149)	\$ 372,283	\$ 420,432	
508	Total Adjustments:									\$ 97,254	\$ 375,167	\$ 277,913	
509													
510	Total Base Revenue for the COSS Class:									\$ 987,779	\$ 1,229,054	\$ 241,275	
511	Total Adjustments for the COSS Class:									\$ 97,254	\$ 375,167	\$ 277,913	
512	Total for the COSS Class:									\$ 1,085,033	\$ 1,604,221	\$ 519,188	47.85%
513													
514	14.02 Real Time Pricing - Secondary Service (Rate 664)												
515	Administrative Charge	Bills			-	\$ 199.00	\$ 199.00	\$220.13	\$220.13				
516	Consumption Change from CBL	kWh			-								
517	Conservation Improvement Program				-								
518	Total:												
519	14.02 Real Time Pricing - Primary Service (Rate 662)												

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
520	Administrative Charge	Bills			-	\$ 199.00	\$ 199.00	\$220.13	\$220.13				
521	Consumption Change from CBL	kWh			-								
522	Conservation Improvement Program				-								
523	Total:												
524	14.02 Real Time Pricing - Transmission Service (Rate 660)												
525	Administrative Charge	Bills			-	\$199.00	\$199.00	\$220.13	\$220.13				
526	Consumption Change from CBL	kWh			-								
527	Conservation Improvement Program				-								
528	Total:												
529	14.03 Large General Service Rider												
530	Administrative Charge	Bills			-	\$199.00	\$199.00	\$220.13	\$220.13				
531	Fixed Rate Energy Pricing (FREP) Peak	kWh			-								
532	Fixed Rate Energy Pricing (FREP) Shoulder	kWh			-								
533	Fixed Rate Energy Pricing (FREP) Off-Peak	kWh			-								
534	Capacity Purchase	kW			-								
535	Conservation Improvement Program				-								
536	Total:												
537													
538	14.04 Controlled Service - Interruptible Load Rider CT Metering - Option 1 (Rates 170, 165, 881)												
539	Customer Charge	Bills			275	\$4.00	\$4.00	\$4.42	\$4.42	\$ 13,189	\$ 14,590	\$ 1,401	
540	Facilities Charge	kW			670,471	\$0.08	\$0.08	\$0.08	\$0.08	\$ 53,638	\$ 53,638	\$ (0)	
541	Energy - All kWh	kWh	8,241,990	57,098,286	65,340,276	\$0.03166	\$0.03044	\$0.04213	\$0.04050	\$ 1,999,013	\$ 2,659,988	\$ 660,975	
542	Penalty kWh	kWh	15,917	99,535	115,452	\$0.39448	\$0.12726	\$0.41350	\$0.14322	\$ 22,480	\$ -	\$ (22,480)	
543	Revenue Adjustment:									\$ 779			
544	Total Base Revenue:									\$ 2,089,099	\$ 2,728,215	\$ 639,116	
545	Adjustments for Riders included in Base Rates					Present	Proposed						
546	Economic Development Adjustment	kWh			65,455,728	-\$0.00013	\$0.00000			\$ (8,525)	\$ -	\$ 8,525	
547	Environmental Cost Recovery Rider Adjustment	%			2,089,099	6.49%	0.00%			\$ 135,619	\$ -	\$ (135,619)	
548	Renewable Resource Adjustment	kWh			65,455,728	\$0.00510	\$0.00000			\$ 333,718	\$ -	\$ (333,718)	
549	Transmission Rider Adjustment	kWh			65,455,728	\$0.00081	\$0.00028			\$ 52,973	\$ 18,651	\$ (34,322)	
550	COE Adjustment	kWh			65,455,728	-\$0.00259	\$0.02544			\$ (169,429)	\$ 1,665,295	\$ 1,834,724	
551	Total Adjustments:									\$ 344,356	\$ 1,683,946	\$ 1,339,589	
552													
553	14.04 Controlled Service - Interruptible Load Rider CT Metering - Option 2 (Rates 168, 268, 169, 269)												
554	Customer Charge	Bills	45	89	134	\$5.00	\$5.00	\$5.53	\$5.53	\$ 669	\$ 740	\$ 71	
555	Facilities Charge	kW	4,480	8,200	12,680	\$0.08	\$0.08	\$0.08	\$0.08	\$ 1,014	\$ 1,014	\$ (0)	
556	Energy - All kWh	kWh	84,310	1,049,540	1,133,850	\$0.03336	\$0.03208	\$0.04435	\$0.04264	\$ 36,482	\$ 48,495	\$ 12,013	
557	Control Period Demand	kW	74	425	499	\$7.29	\$5.61	\$8.44	\$6.49	\$ 2,924	\$ 3,383	\$ 459	
558	Total Base Revenue:									\$ 41,089	\$ 53,633	\$ 12,544	
559	Adjustments for Riders included in Base Rates					Present	Proposed						
560	Economic Development Adjustment	kWh			1,133,850	-\$0.00013	\$0.00000			\$ (148)	\$ -	\$ 148	
561	Environmental Cost Recovery Rider Adjustment	%			41,089	6.49%	0.00%			\$ 2,667	\$ -	\$ (2,667)	
562	Renewable Resource Adjustment	kWh			1,133,850	\$0.00510	\$0.00000			\$ 5,781	\$ -	\$ (5,781)	
563	Transmission Rider Adjustment	kWh			1,133,850	\$0.00081	\$0.00028			\$ 918	\$ 323	\$ (595)	
564	COE Adjustment	kWh			1,133,850	-\$0.00259	\$0.02544			\$ (2,935)	\$ 28,847	\$ 31,782	
565	Total Adjustments:									\$ 6,283	\$ 29,170	\$ 22,887	
566													
567	14.05 Controlled Service - Interruptible Load Rider Self-Contained Metering (Rates 190, 185, 882)												
568	Customer Charge	Bills			-	\$2.00	\$2.00	\$2.21	\$2.21	\$ 184,644	\$ 204,251	\$ 19,607	
569	Facilities Charge	Bills			92,322	\$5.00	\$5.00	\$5.00	\$5.00	\$ 461,609	\$ 461,609	\$ 0	
570	Energy - All kWh	kWh	12,458,471	117,741,633	130,200,104	\$0.03659	\$0.03451	\$0.04888	\$0.04610	\$ 4,519,031	\$ 6,037,106	\$ 1,518,075	
571	Penalty kWh	kWh	279	2,262	2,541	\$0.38606	\$0.12924	\$0.41350	\$0.16537	\$ 488		\$ (488)	

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
572	Total Base Revenue:									\$ 5,165,773	\$ 6,702,966	\$ 1,537,193	
573	Adjustments for Riders included in Base Rates					Present	Proposed						
574	Economic Development Adjustment	kWh			130,200,104	-\$0.00013	\$0.00000			\$ (16,958)	\$ -	\$ 16,958	
575	Environmental Cost Recovery Rider Adjustment	%			5,165,773	6.49%	0.00%			\$ 335,349	\$ -	\$ (335,349)	
576	Renewable Resource Adjustment	kWh			130,200,104	\$0.00510	\$0.00000			\$ 663,810	\$ -	\$ (663,810)	
577	Transmission Rider Adjustment	kWh			130,200,104	\$0.00081	\$0.00028			\$ 105,370	\$ 37,099	\$ (68,271)	
578	COE Adjustment	kWh			130,200,104	-\$0.00259	\$0.02544			\$ (337,018)	\$ 3,312,491	\$ 3,649,509	
579	Total Adjustments:									\$ 750,553	\$ 3,349,591	\$ 2,599,037	
580													
581													
582	Total Base Revenue for the COSS Class:									\$ 7,295,962	\$ 9,484,814	\$ 2,188,852	
583	Total Adjustments for the COSS Class:									\$ 1,101,193	\$ 5,062,706	\$ 3,961,514	
584	Total for the COSS Class:									\$ 8,397,155	\$ 14,547,520	\$ 6,150,366	73.24%
585													
586													
587													
588	14.06 Controlled Service - Deferred Load Rider (Rates 197, 195, 883)												
589	Customer Charge	Bills			9,515	\$3.00	\$3.00	\$3.32	\$3.32	\$ 28,544	\$ 31,575	\$ 3,031	
590	Facilities Charge	Bills			9,515	\$4.00	\$4.00	\$4.00	\$4.00	\$ 38,058	\$ 38,058	\$ (0)	
591	Energy - All kWh	kWh	1,115,150	15,873,655	16,988,805	\$0.05154	\$0.05002	\$0.06659	\$0.06463	\$ 851,475	\$ 1,100,139	\$ 248,664	
592	Penalty kWh	kWh	37	1,828	1,865	\$0.33802	\$0.11510	\$0.35916	\$0.16537	\$ 316	\$ -	\$ (316)	
593	Total Base Revenue:									\$ 918,394	\$ 1,169,773	\$ 251,379	
594	Adjustments for Riders included in Base Rates					Present	Proposed						
595	Economic Development Adjustment	kWh			16,990,670	-\$0.00016	\$0.00000			\$ (2,758)	\$ -	\$ 2,758	
596	Environmental Cost Recovery Rider Adjustment	%			918,394	6.49%	0.00%			\$ 59,620	\$ -	\$ (59,620)	
597	Renewable Resource Adjustment	kWh			16,990,670	\$0.00510	\$0.00000			\$ 86,658	\$ -	\$ (86,658)	
598	Transmission Rider Adjustment	kWh			16,990,670	\$0.00089	\$0.00031			\$ 15,168	\$ 5,341	\$ (9,828)	
599	COE Adjustment	kWh			16,990,670	-\$0.00241	\$0.02562			\$ (40,940)	\$ 435,309	\$ 476,249	
600	Total Adjustments:									\$ 117,748	\$ 440,650	\$ 322,901	
601													
602	14.07 Fixed Time of Service Rider - Self-Contained Metering (Rates 301, 884)												
603	Customer Charge	Bills	1,346	2,704	4,049	\$1.00	\$1.00	\$1.11	\$1.11	\$ 4,050	\$ 4,480	\$ 430	
604	Facilities Charge	Bills	1,346	2,704	4,049	\$3.00	\$3.00	\$3.00	\$3.00	\$ 12,148	\$ 12,148	\$ 0	
605	Energy - All kWh	kWh	133,534	6,324,579	6,458,113	\$0.02774	\$0.02937	\$0.03859	\$0.04085	\$ 189,457	\$ 263,535	\$ 74,078	
606	Penalty kWh	kWh	15,850	341,830	357,680	\$0.09400	\$0.07385	\$0.06736	\$0.04602	\$ 37,213	\$ -	\$ (37,213)	
607	Total Base Revenue:									\$ 242,868	\$ 280,163	\$ 37,295	
608	Adjustments for Riders included in Base Rates					Present	Proposed						
609	Economic Development Adjustment	kWh			6,815,793	-\$0.00016	\$0.00000			\$ (1,106)	\$ -	\$ 1,106	
610	Environmental Cost Recovery Rider Adjustment	%			242,868	6.49%	0.00%			\$ 15,766	\$ -	\$ (15,766)	
611	Renewable Resource Adjustment	kWh			6,815,793	\$0.00510	\$0.00000			\$ 34,763	\$ -	\$ (34,763)	
612	Transmission Rider Adjustment	kWh			6,815,793	\$0.00089	\$0.00031			\$ 6,085	\$ 2,142	\$ (3,942)	
613	COE Adjustment	kWh			6,815,793	-\$0.00241	\$0.02562			\$ (16,422)	\$ 174,624	\$ 191,046	
614	Total Adjustments:									\$ 39,086	\$ 176,766	\$ 137,681	
615													
616	14.07 Fixed Time of Service Rider - CT Metering (Rates 302, 885)												
617	Customer Charge	Bills	224	451	674	\$1.50	\$1.50	\$1.66	\$1.66	\$ 1,012	\$ 1,119	\$ 107	
618	Facilities Charge	Bills	224	451	674	\$19.00	\$19.00	\$19.00	\$19.00	\$ 12,815	\$ 12,815	\$ 0	
619	Energy - All kWh	kWh	138,334	4,855,242	4,993,576	\$0.02774	\$0.02937	\$0.03810	\$0.04034	\$ 146,436	\$ 201,129	\$ 54,693	
620	Penalty kWh	kWh	21,303	131,829	153,132	\$0.09400	\$0.07385	\$0.06736	\$0.04602	\$ 16,201	\$ -	\$ (16,201)	
621	Total Base Revenue:									\$ 176,464	\$ 215,064	\$ 38,600	
622	Adjustments for Riders included in Base Rates					Present	Proposed						
623	Economic Development Adjustment	kWh			5,146,708	-\$0.00016	\$0.00000			\$ (835)	\$ -	\$ 835	

Proposed Test Year 2018 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase	Pct Inc.
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual	Annual	Annual
624	Environmental Cost Recovery Rider Adjustment	%			176,464	6.49%	0.00%			\$ 11,456	\$ -	\$ (11,456)	
625	Renewable Resource Adjustment	kWh			5,146,708	\$0.00510	\$0.00000			\$ 26,250	\$ -	\$ (26,250)	
626	Transmission Rider Adjustment	kWh			5,146,708	\$0.00089	\$0.00031			\$ 4,595	\$ 1,618	\$ (2,977)	
627	COE Adjustment	kWh			5,146,708	-\$0.00241	\$0.02562			\$ (12,401)	\$ 131,861	\$ 144,262	
628	Total Adjustments:									\$ 29,064	\$ 133,479	\$ 104,415	
629													
630	14.07 Fixed Time of Service Rider - Primary CT Metering (Rates 303, 886)												
631	Customer Charge	Bills			-	\$3.00	\$3.00	\$6.70	\$6.70				
632	Facilities Charge	Bills			-	\$9.00	\$9.00	\$18.00	\$18.00				
633	Energy - All kWh	kWh			-	\$0.02763	\$0.02926	\$0.01519	\$0.01680				
634	Penalty kWh	kWh			-	\$0.09389	\$0.07374	\$0.06736	\$0.04602				
635													
636													
637													
638	Total Base Revenue for the COSS Class:									\$ 1,337,726	\$ 1,664,999	\$ 327,273	
639	Total Adjustments for the COSS Class:									\$ 185,898	\$ 750,895	\$ 564,997	
640	Total for the COSS Class:									\$ 1,523,624	\$ 2,415,894	\$ 892,270	58.56%
641													
642													
643													
644	Total Base Revenue:									\$ 128,789,179	\$ 163,729,094	\$ 34,939,915	
645	Total Adjustments:									\$ 19,282,363	\$ 47,732,638	\$ 28,450,275	
646	TOTAL :									\$ 148,071,542	\$ 211,461,732	\$ 63,390,190	42.81%

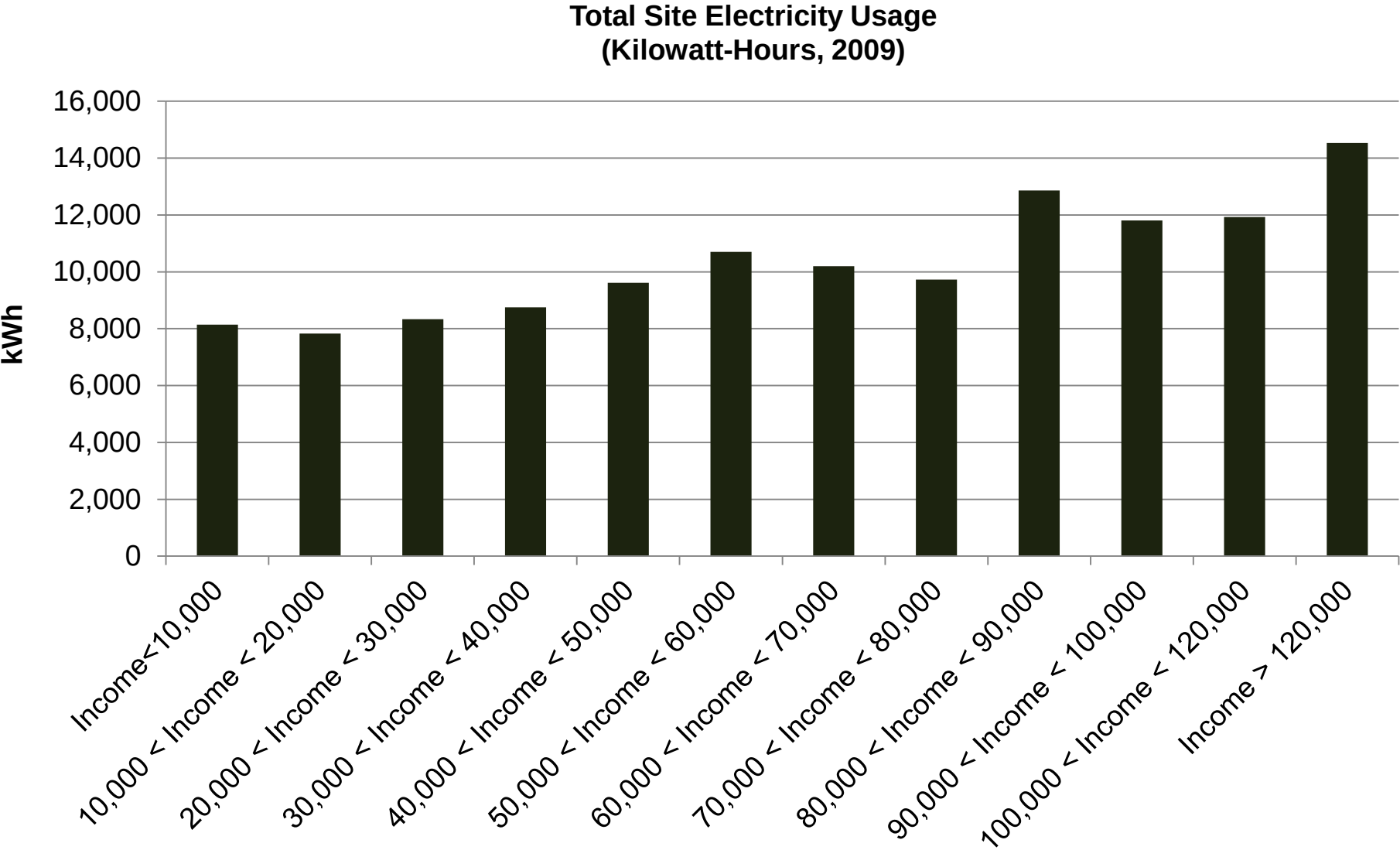
	Residential Service		Farm Services		General Service			Large General Service	
	Residential Service	Residential Demand Control Service	Farm Service Single Phase	Farm Service Three Phase	Sm. General Service	General Service (Secondary)	General Service TOU	Large General Service Secondary	Large General Service Time of Day Primary
Current Charge	\$8.00	\$18.38	\$12.00	\$12.00	\$13.00	\$12.00	\$16.00	\$40.00	\$60.00
Proposed Charge	\$17.70	\$20.10	\$17.40	\$17.40	\$24.90	\$31.90	\$219.00	\$215.90	\$282.00
Percentage Difference	121.3%	9.4%	45.0%	45.0%	91.5%	165.8%	1268.8%	439.8%	370.0%

Source: Direct Testimony of David G. Prazak, Table 6 through Table 24.

Prepared by: TJD 04/09/2018
Reviewed by: SB 5/8/18

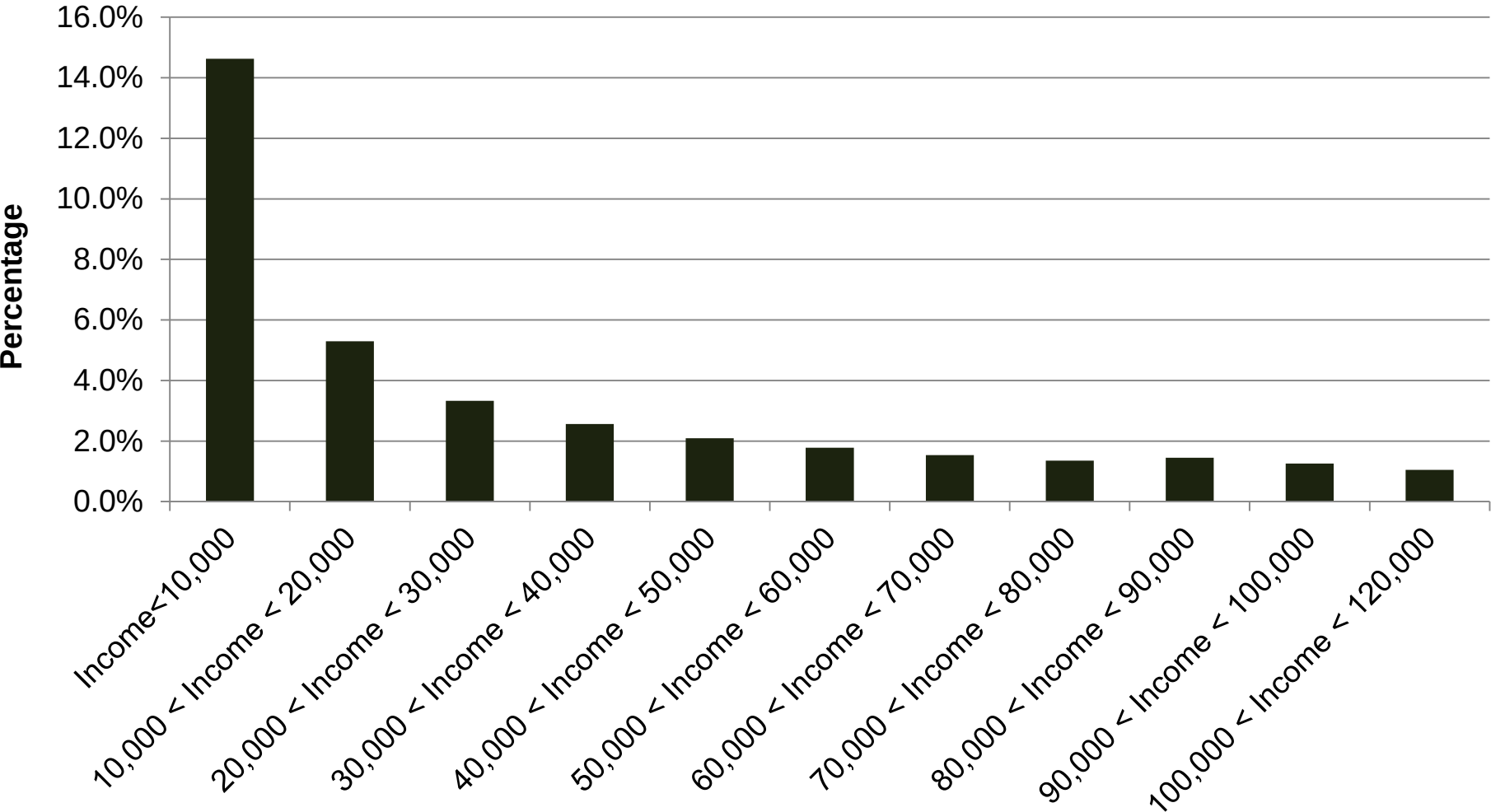
	Outdoor Lighting		Controlled Service			Irrigation Option 1	Irrigation Option 2	Municipal Pumping	Civil Defense	Water Heating	Deferred Load Service	Fixed Time of Service Secondary
	Outdoor Lighting Metered	Non-metered	Controlled Service Interruptible Large #1	Controlled Service Interruptible Large #2	Controlled Service Interruptible small							
Current Charge	\$2.00	\$0.00	\$4.00	\$5.00	\$2.00	\$1.00	\$5.00	\$4.00	\$1.00	\$1.00	\$3.00	\$1.50
Proposed Charge	\$2.00	\$0.00	\$20.20	\$20.20	\$8.50	\$24.30	\$24.30	\$26.50	\$1.22	\$4.00	\$8.80	\$6.70
Percentage Difference	0.0%	0.0%	405.0%	304.0%	325.0%	2330.0%	386.0%	562.5%	22.0%	300.0%	193.3%	346.7%

[illegible]



Source: Energy Information Administration, Residential Electricity Consumption Survey (“RECS”)

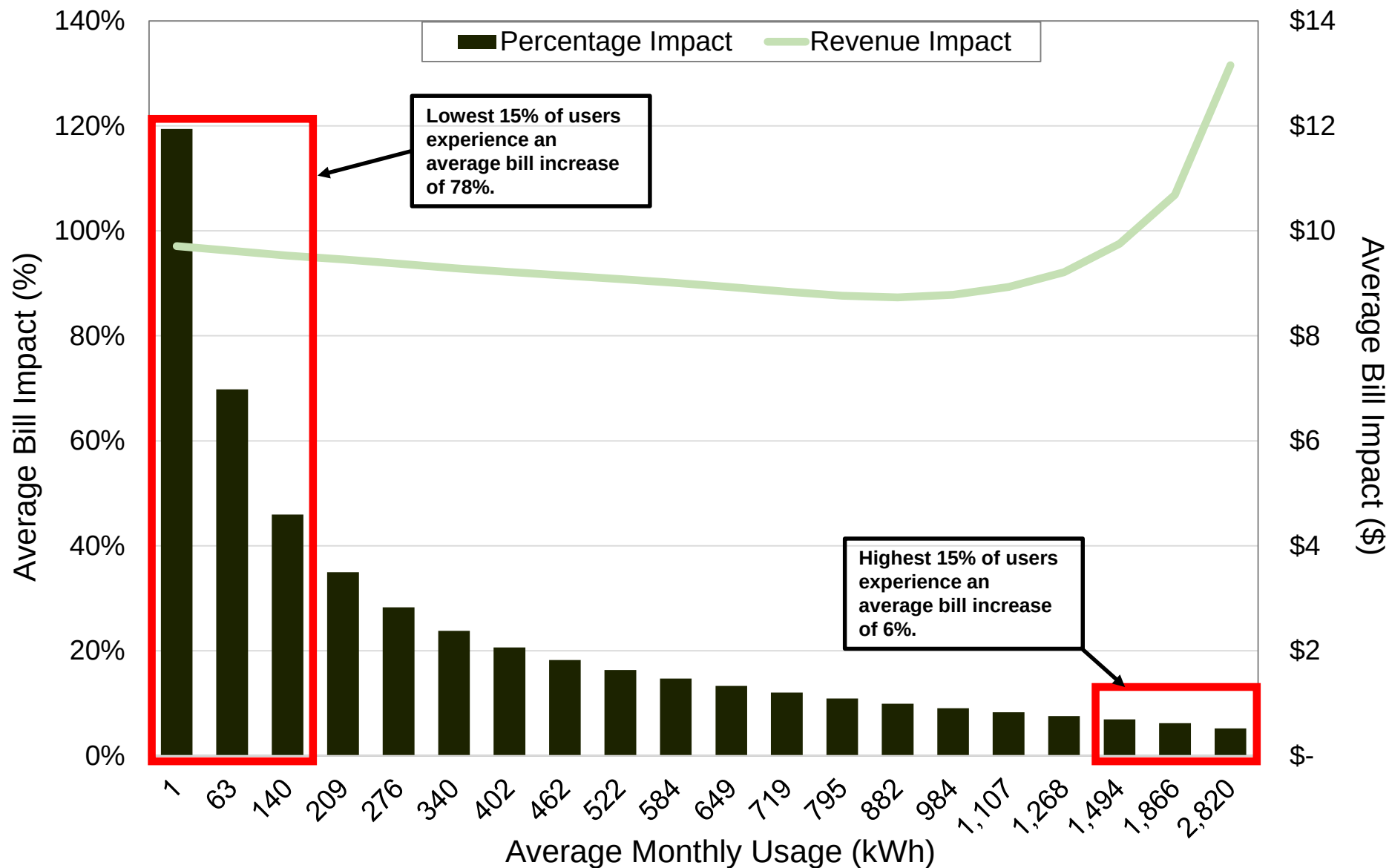
Consumption as Percent of Income



Source: Energy Information Administration, Residential Electricity Consumption Survey ("RECS")



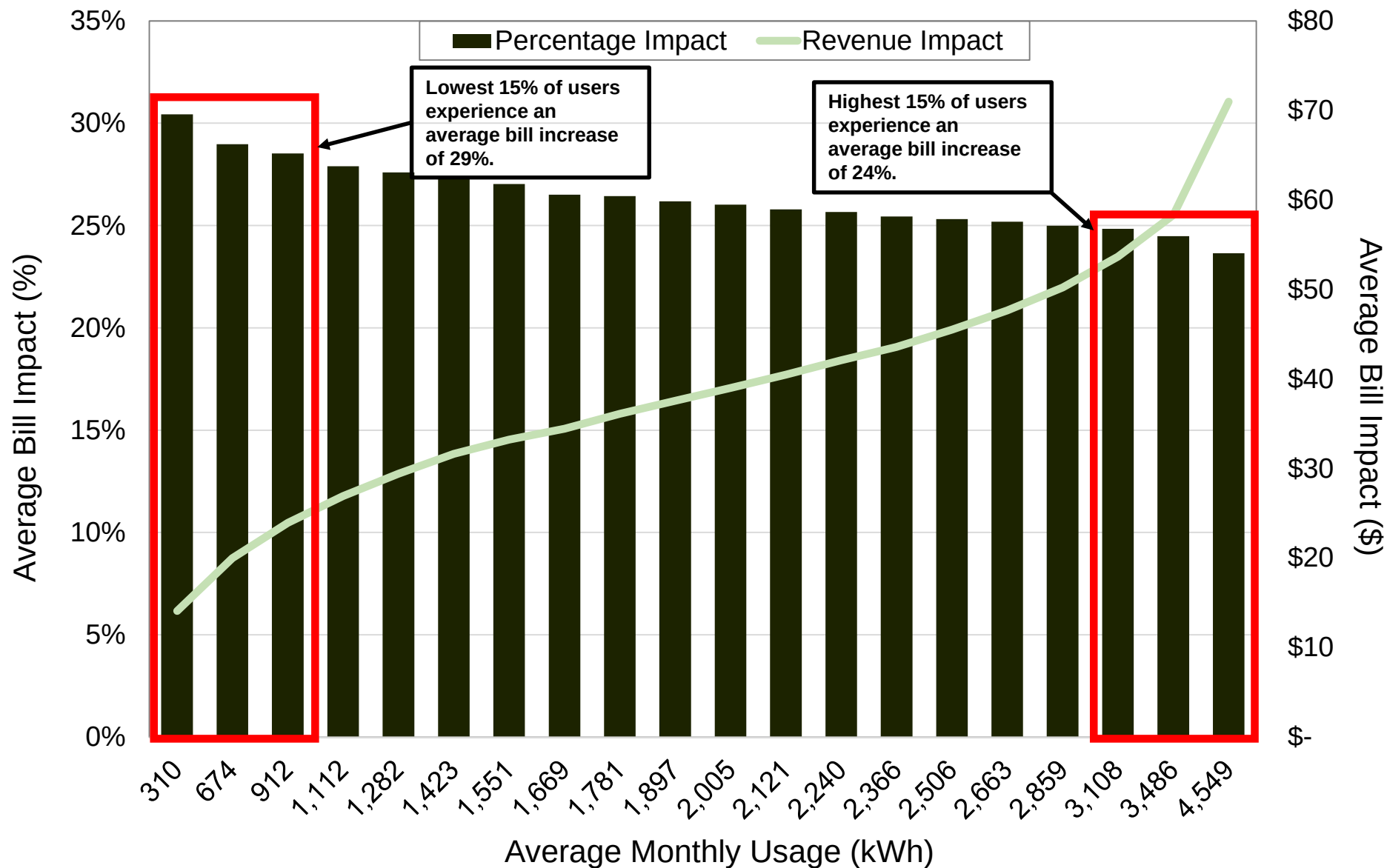
Average Bill Impact by Usage: Residential Service



Source: Company response to ND-PSC-04.18

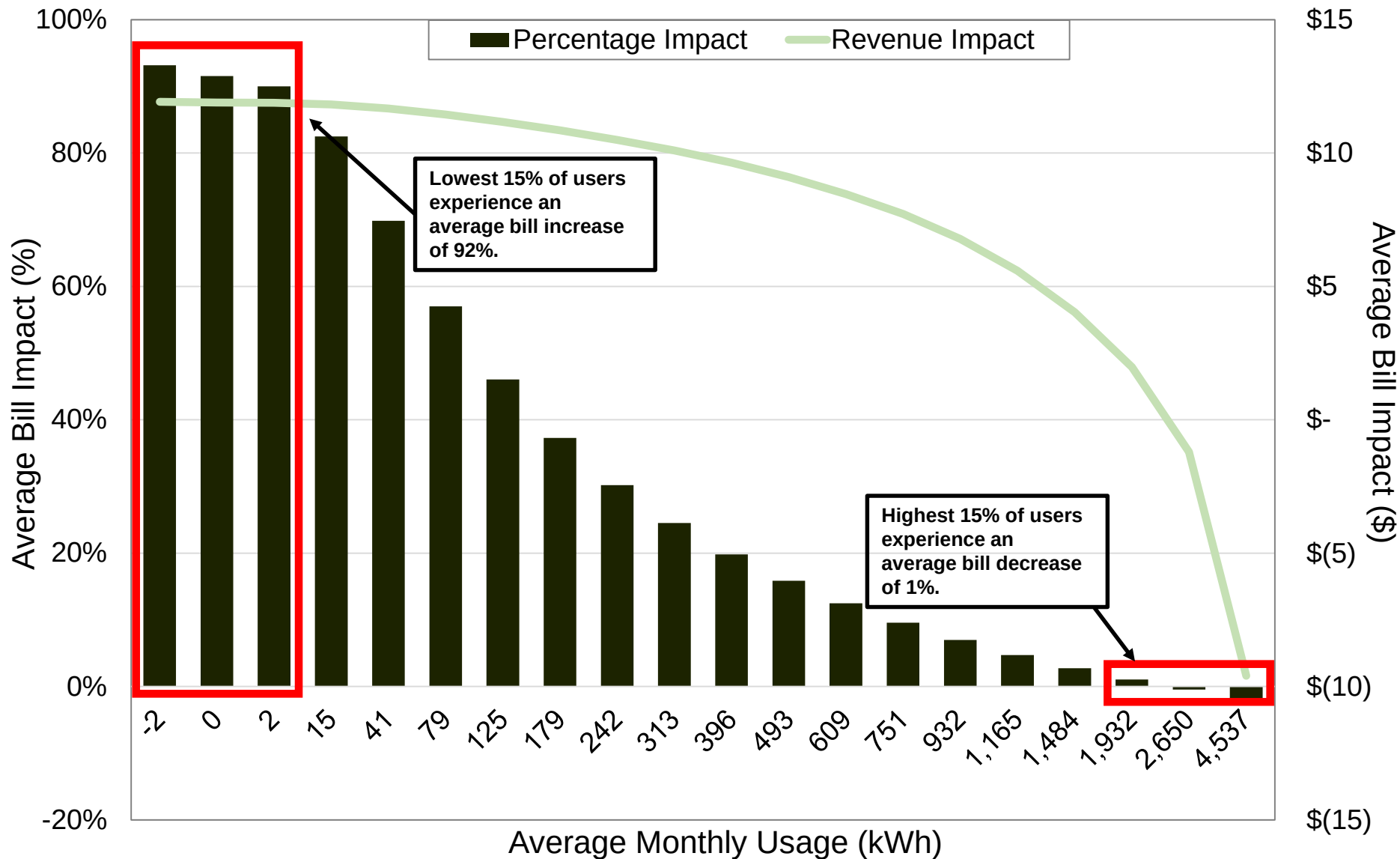


Average Bill Impact by Usage: Residential Demand Control





Average Bill Impact by Usage: Small General Service



Source: Company response to ND-PSC-04.18

Regional Customer Charge Survey

State	Company	Residential Rate	Small Commercial Rate		
IA	Interstate Power and Light Co ¹	\$13.50	\$24.00		
IA	MidAmerican Energy Co ¹	\$8.50	\$10.00		
MN	ALLETE, Inc. ^{1,2}	\$8.00	\$10.50		
MN	Northern States Power Co	\$8.00	\$10.00		
MN	Otter Tail Power Co ¹	\$9.75	\$27.00		
MT	Montana-Dakota Utilities Co ³	\$5.17	\$15.21		
MT	NorthWestern Energy LLC ¹	\$4.10	\$7.35		
ND	Montana-Dakota Utilities Co ³	\$13.99	\$25.55		
ND	Northern States Power Co ⁴	\$14.50	\$16.75		
ND	Otter Tail Power Co ¹	\$8.00	\$12.00	\$12.08	\$16.95
SD	Montana-Dakota Utilities Co ³	\$7.51	\$15.51		
SD	MidAmerican Energy Co ¹	\$8.00	\$10.00		
SD	Northern States Power Co	\$8.25	\$9.00	\$10.38	\$16.00
SD	NorthWestern Energy ¹	\$6.00	\$10.00		
SD	Otter Tail Power Co ¹	\$8.00	\$12.00		
SD	Black Hills Power, Inc. ¹	\$9.25	\$12.00		
WI	Madison Gas & Electric Co ³	\$19.00	\$23.93		
WI	Northern States Power Co ⁴	\$17.00	\$17.00		
WI	Northwestern Wisconsin Elec Co ¹	\$11.00	\$16.00		
WI	Superior Water and Light Co ¹	\$9.00	\$10.00		
WI	Wisconsin Electric Power Co ^{1,3}	\$16.00	\$16.00		
WI	Wisconsin Power & Light Co ^{1,3}	\$15.00	\$17.00		
WI	Wisconsin Public Service Corp	\$21.00	\$27.63		
WY	Cheyenne Light Fuel & Power d/b/a Black Hills Energy ¹	\$13.00	\$16.00		
WY	Montana-Dakota Utilities Co ³	\$25.00	\$29.99		
WY	PacifiCorp ⁵	\$20.00	\$24.25		
WY	Black Hills Power, Inc. ¹	\$15.50	\$28.00		

Source: Company Tariffs.

¹The lowest General Service rate is used due to lack of Small Commercial Service rates on companies' tariffs.

²Residential and Commercial rates pulled from Minnesota Power, a division of Allete. Seasonal residential charge is \$8.80.

³Rates are daily rates multiplied by 365 and divided by 12 for monthly average.

⁴Residential and Commercial charges are pulled from Xcel Energy, which owns Northern States Power Co.

⁵Residential and Commercial charges are pulled from Rocky Mountain Power in Wyoming, a division of PacifiCorp.

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