BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St. Paul, Minnesota 55101-2147

In the Matter of the Application of
DAKOTA ELECTRIC ASSOCIATION,
for Authority to Increase Rates
for Electric Service in Minnesota

MPUC Docket No. E-111/GR-14-482
OAH Docket No. 80-2500-31796

INITIAL BRIEF OF DAKOTA ELECTRIC ASSOCIATION

January 20, 2015

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I. INTRODUCTION

This Initial Brief is submitted in support of Dakota Electric Association's ("DEA", "Dakota Electric", or "Cooperative") application for authority to increase its rates for electric service in Minnesota. This Initial Brief will primarily address those issues which remain contested. Uncontested issues will be addressed in the Cooperative's proposed findings to be submitted with DEA's Reply Brief.

Dakota Electric has requested an overall increase in annual revenues of approximately 2.1% or $4,189, 000. As a member-owned cooperative association (ratepayers are its members), DEA proposes an increase in rates only when absolutely necessary, at which time appropriate adjustments are made amongst its rate classes. The revenue increase proposed in this proceeding has been approved by Dakota Electric's twelve person board of directors who are also member-owners of the Cooperative. The Board of Directors is elected by DEA's member-owners, which are the same persons as the ratepayers.

As an electric cooperative, DEA allocates any margins or "profits" annually to its member-owners. This protection for consumers is unique to cooperative associations as compared to investor-owned utility companies. If this revenue increase is not approved, any unrecovered costs will have to be collected through a future rate case, which will come sooner rather than later and add more costs.

Dakota Electric and the Minnesota Department of Commerce – Division of Energy Resources ("DOC" or "Department") narrowed the contested issues between them and reached a Settlement Agreement that was entered into the evidentiary record during the hearing on December 18, 2014. This Settlement Agreement resolves all contested issues between the

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Cooperative and the Department.[1] There are remaining disputed issues with the Office of the Attorney General – Antitrust and Utilities Division ("OAG"). Those issues will be the focus of this Initial Brief.

II. DISPUTED ISSUES

1. Financial Issues

Financial issues in dispute include a) travel and miscellaneous expenses, b) adjustment for staffing changes, and c) support hours formerly provided to Energy Alternatives, Inc. (EAI) a DEA subsidiary.

a) Travel and miscellaneous expenses (Disputed Issue #1)

The OAG recommends disallowance of $10,310 of travel and miscellaneous expenses consisting of 1) $2,066 of travel reimbursement for a DEA director running for election to the CFC Board of Directors, 2) $672 for half the cost of an airfare that was booked days before the trip, 3) $3,909 in grocery and food expenses for various company and department functions, 4) $522 for the DEA Board December holiday lunch, and 5) $3,141 for the retirement gathering for the Cooperative's attorney.[2] Dakota Electric agreed that the retirement dinner expenses for the Cooperative's long-time attorney should be removed from the test year, but that all other travel and miscellaneous expenses should be approved for rate recovery.[3]

(1) Travel Reimbursement. The director travel expense was for a DEA director to attend regional meetings of electric cooperatives in Minnesota and North and South Dakota while he was running for election to the CFC board of directors. Potential participation on the board of directors of a major Dakota Electric lender has significant value. A CFC director may

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[1] Ex. 128, Settlement Agreement.
[2] Ex. 203, Lee Direct pp. 12 – 14 and Ex. 205, Lee Surrebuttal p. 13.
[3] Ex. 126, Larson Rebuttal pp. 36 – 37 and Ex. 127, Larson Surrebuttal p. 21.

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help design lending policies directly related to the provision of electric service and should be included as an expense in the test year.[4] There is no evidence that these travel expenses were related to the director's personal employment agenda as stated by OAG witness Lee.[5]

(2) Airfare. The airfare in question was secured days before the event, when it was determined that DEA did not have anyone attending this conference.[6] A DEA director was able to free up her schedule at the last minute to attend the conference. While last minute arrangements increased the cost of airfare, which happens from time to time in this business world, the expense was justified in this instance due to the importance of attending the conference.

(3) Food Expense. Dakota Electric provided detailed expense documentation on the various food expenses.[7] There is no dispute that these expenses were all incurred at legitimate company and department functions and meetings. They included employee wellness events in an effort to reduce medical claims; working lunches for departments like engineering, customer service, and member services; and staff working lunches. Management certainly has the prerogative of providing food and beverages at these meetings to keep employees refreshed, alert, and productive in the interest of assuring productive meetings.

(4) Board Holiday Lunch. Finally, OAG objected to $522.00 for the December holiday lunch of the Board of Directors. Despite the "holiday" label, this December lunch was no different from other monthly lunch breaks that the Board of Directors takes during its regular meetings for the other eleven months of the year.

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[4] Ex. 126, Larson Rebuttal pp. 16-17.
[5] Ex. 204, Lee Rebuttal p. 10.
[6] Ex. 126, Larson Rebuttal p. 17.
[7] Ex. 205, Lee Surrebuttal (OAG Information Request 806, attached as Schedule SL-15).

These expenses were all legitimate costs of doing the administrative business necessary to provide electric service.

b) Adjustment for staffing changes (Disputed Issue #2)

The OAG recommends disallowance of the $690,427 adjustment made by Dakota Electric for staffing changes that occurred within the test year based on a comparison of total test year compensation with a four year historical average level of compensation from 2010-2013.[8] The OAG's four year average payroll is outdated information.

Dakota Electric's adjustment for staffing changes applied to the historical test year reflects a full year of compensation and benefits for all existing positions at the Cooperative.[9] The positions identified for the compensation adjustment are existing positions.[10] Disallowing this annualization adjustment has the net effect of removing from rate recovery the compensation and benefits of six existing Dakota Electric positions.[11] Additionally, the Powerline Design Technician position was filled by mid-2014 as reflected in the annualization adjustment.[12]

Furthermore, 2013 was an atypical year in terms of vacancies in staff positions. An engineer left DEA but returned two months later. A technician was hired away by another utility, a rare occurrence, which sent ripples through the organization. A lead member service representative was stricken with cancer, and her position was held open, hoping she could return. A crew chief developed cancer and died.[13] These unusual events tend to distort the job vacancy data beyond the normal employee turnover. DEA's compensation adjustment recognizes the existing level of staffing that should be included in the test year and recovered through rates.

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[8] Ex. 203, Lee Direct pp. 5 – 7 and Ex. 205, Lee Surrebuttal p. 13.
[9] Ex. 126, Larson Rebuttal p. 36 and Ex. 127, Larson Surrebuttal p. 21.
[10] Ex. 126, Larson Rebuttal p. 13.
[11] Ex. 102, Exhibit DEA-1 of Larson Direct p. 5 (($1,040,494 - $643,269)/$1,040,494)*16 positions = 6.1 positions
[12] Ex. 203, Lee Direct at SL-4 (DEA response to OAG IR 803).
[13] Tr. p. 25 and Ex. 203, Lee Direct at SL-4 (DEA response to OAG IR 803).

c) **Support hours formerly provided to EAI** (Disputed Issue #3)

The OAG recommends disallowance of the labor costs associated with 842 hours that were provided and charged to the Cooperative's subsidiary in 2010, but included in Dakota Electric's regulated operations in the test year due to the subsidiary requiring less support.[14]

No adjustment for hours no longer devoted to subsidiary activities is warranted.[15] The OAG analysis and recommended exclusion is based on a comparison of hours devoted to the subsidiary in 2010 compared to the 2013 test year. The identified 842 hours are attributed to the difference in hours charged by 23 different employees. The change in hours for these employees ranged from half an hour to 243.5 hours per employee.[16] Only two hourly employees charged time to the subsidiaries with the balance being salaried employees who often work more than a forty hour week or a 2,080 hour year. Salaried employees with a reduction in time charged include the CEO, Vice President of Finance and the Corporate Controller.

Since 2010, changes have been made to the responsibilities of various positions that may have previously charged time to subsidiaries.[17] A reduction to test year expenses for hours no longer devoted to subsidiary activities is not warranted. The identified employees and hours are all being devoted to regulated utility business. Times change in a business. All labor costs associated with the identified 842 hours should be included in the test year and recovered through rates.

2. **<u>Class Cost of Service Study</u>** (Disputed Issue #4)

A class cost of service study ("CCOSS") is a method by which a utility allocates costs to its various classes of consumers. Generally, these costs are direct or indirect/shared costs. The

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[14] Ex. 203, Lee Direct p. 8 and Ex. 205, Lee Surrebuttal p. 13.
[15] Ex. 126, Larson Rebuttal p. 36 and Ex. 127, Larson Surrebuttal p. 21.
[16] Tr., p. 40.
[17] Tr., p. 41.

objective of performing a CCOSS is to measure, as closely as possible, the cost impact that a particular class has on the system. Generally, the result of a CCOSS is the starting point or one factor to be weighed in revenue apportionment and setting rates.

For Dakota Electric, the largest portion of costs to serve members is in essence a pass-through of demand and energy charges that are billed by DEA's wholesale power supplier, Great River Energy ("GRE"). For the CCOSS allocation purposes, DEA does not make any modification to the charges from GRE, so these allocations are actual, direct costs of service and are incurred based on how the class impacts the charges from GRE. These charges amount to about 74% of the costs in the CCOSS.[18] Beyond these wholesale power costs, the CCOSS deals with how to allocate the remaining 26% of costs necessary to provide electric distribution service. DEA uses a fully allocated average embedded methodology for its CCOSS meaning that; 1) costs are allocated on an average system-wide basis and 2) embedded or accounting costs as recorded on the Cooperative's books are used in the analysis.[19] Cost allocation is based on factors that reflect cost causative drivers for the expenses being allocated.

Dakota Electric's filing included a cost of service study that uses the same model approved by the Commission in the Cooperative's 2009 general rate case (Docket No. E-111/GR-09-175), with two modifications.[20] The first modification is use of the minimum-size method to determine the relative amount of specified distribution accounts to classify as "consumer" costs.[21] The second modification was the inclusion of a new wholesale power energy charge.[22]

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[18] Ex. 104, Exhibit DEA-3 of Larson Direct p. 2.
[19] Ex. 101, Larson Direct p. 20.
[20] Ex. 101, Larson Direct p. 20 and Ex. 104, Exhibit DEA-3 of Larson Direct.
[21] Ex. 101, Larson Direct p. 21 and Ex. 125, Workpaper 21.
[22] Ex. 101, Larson Direct p. 21.

The DOC and OAG evaluated Dakota Electric's class cost of service study. The Department concluded that Dakota Electric's proposed CCOSS is reasonable. The Department recommended that the Commission adopt Dakota Electric's proposed class cost of service study.[23] Dakota Electric concurred with the Department's recommendation to adopt the CCOSS.[24]

The OAG objected to the Cooperative's use of the minimum-size method to determine the relative amount of specified distribution accounts to classify as "consumer" costs.[25] The OAG recommends use of an alternative analysis, referred to as the zero-intercept proxy, to determine the relative amount of specified distribution accounts to classify as "consumer" costs.[26]

The single issue in dispute regarding Dakota Electric's CCOSS is the appropriate methodology to use for the classification of certain distribution plant accounts. In all previous general rate cases, Dakota Electric used a zero-intercept analysis to classify the cost of DEA's "customer" component of distribution facilities. Distribution facilities generally are broken down between "demand" and "customer" related costs. Paragraph 6 of the Commission's Order in DEA's 2009 rate case stated as follows:

> "6. Dakota Electric shall, in its next rate case, either use the minimum-size method to classify distribution accounts, or provide such an analysis to support the outcome of the zero-intercept method."

Since DEA determined that the same concerns with the zero-intercept pointed out by OAG in the 2009 rate case could still exist, DEA opted to use the minimum-size method to classify specified distribution accounts in this case.

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[23] Ex. 301, Ruzycki Direct p. 15; Ex. 302, Ruzycki Rebuttal p. 7; and Ex. 303, Ruzycki Surrebuttal p. 8.
[24] Ex. 126, Larson Rebuttal p. 6 and Ex. 127, Larson Surrebuttal p. 20.
[25] Ex. 200, Nelson Direct p. 16; Ex. 201, Nelson Rebuttal pp. 4 to 5; and Ex. 202, Nelson Surrebuttal p. 10.
[26] Ex. 200, Nelson Direct p. 20 and Ex. 202, Nelson Surrebuttal p. 10.

Workpaper 21 describes the calculation of minimum-size classification factors for the respective distribution accounts and compares the overall results to the overall classification using the zero-intercept method from the 2009 case.[27] Dakota Electric's minimum-size analysis is consistent with the approach described in the National Association of Regulatory Commissioners (NARUC) Electric Utility Cost Allocation Manual (NARUC Manual) as described in Workpaper 21. The equipment used in the analysis for each plant account is the minimum-size currently being installed related to the utility primary backbone system. Dakota Electric's minimum-size analysis contained in Workpaper 21 also provided a comparison of the weighted average minimum-size consumer classification (sum of minimum costs divided by sum of installed book costs) for Accounts 364, 365, 367 and 368. This weighted average is 61.5 percent. This was compared to the weighted average zero-intercept consumer classifications of 57.1 percent used in Dakota Electric's 2009 general rate case.[28]

The OAG proposed alternative analysis, referred to as the zero-intercept proxy, is flawed and highly theoretical. The OAG analysis ignores the minimum cost of materials necessary to provide basic service. Accordingly, it underestimates the no-load cost of transformers and the other plant accounts subject to this analysis. The OAG alternative method is a "zero-system" analysis.[29] The assertion that the cheapest distribution equipment should be used for a minimum system analysis is also not consistent with the direction provided in the NARUC Manual.[30] The OAG analysis is also performed using installation costs for plant installed over a 30 to 40 year time frame.[31]

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[27] Ex. 101, Larson Direct p. 21.
[28] Ex. 126, Larson Rebuttal pp. 22 to 23 and Ex. 127, Larson Surrebuttal pp. 11 to 12.
[29] Ex. 126, Larson Rebuttal p. 28.
[30] Ex. 126, Larson Rebuttal p. 28.
[31] Ex. 127, Larson Surrebuttal p. 13.

The OAG also criticized the Cooperative for not modifying a demand allocator in the CCOSS to account for potential load carrying capability of plant included in the minimum-size analysis. However, there are two main reasons why a demand adjustment to Dakota Electric's minimum-size results is not appropriate. First, the zero-intercept analysis does a reasonable job of estimating the proportion of identified plant accounts for consumer classification for a system with no load carrying capability as demonstrated by the weighted average benchmark comparison of the zero-intercept method and minimum-size method. Since the minimum-size results are similar to the zero-intercept results, a demand adjustment is not needed or warranted.

Second, the minimum-size analysis relies on the average book cost for each piece of plant. The average book cost reflects the cost of plant installed 30 to 40 years ago up to the present day. For a particular piece of plant, the majority of such plant could have been installed years ago or more recently. Accordingly, the minimum-size plant could reflect an unusually low cost (if the majority of plant was installed years ago) or it could reflect an unusually high cost (if the majority of plant was installed more recently). Making an arbitrary demand adjustment to account for the load carrying capacity of the minimum-size equipment only adds potential distortion to the plant classification process for Dakota Electric.[32]

The OAG is attempting to usurp a business decision that DEA was ordered to make in the 2009 rate case, i.e., to use the minimum-size method if it could not support the zero-intercept method. DEA made a reasonable decision to switch to the use of the minimum-size method to avoid the concerns with the zero-intercept method. Now the OAG asserts that its alternative method, which the Commission has never adopted in any previous rate case, should be applied in DEA's rate case. Finally, the OAG proposed alternative method produces a weighted customer

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[32] Ex. 127, Larson Surrebuttal pp. 12 to 13.

component of 38% of distribution plant costs as opposed to a weighted 57.1% from the zero-intercept method in DEA's last rate case and 61.5% from the minimum-size method used by DEA in this case. The clear outlier in these comparative methodologies is the OAG's. DEA's CCOSS should be approved.

To summarize, Dakota Electric's minimum-size analysis is 1) consistent with the approach to this analysis described in the NARUC Manual, 2) yields weighted results similar to the zero-intercept analysis from our 2009 general rate case, and 3) does not require any adjustment to demand allocators. The OAG analysis 1) has no basis in recognized methods in the NARUC Manual, 2) proposes an alternative approach that excludes equipment costs, and 3) under-states the consumer classification of identified plant accounts.[33]

3. Revenue Apportionment and Rate Design

Minnesota law gives guidance on the design of rates. Specifically, Minn. Stat. § 216B.03 provides:

> Every rate made, demanded, or received by any public utility, or by any two or more public utilities jointly, shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers. To the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05.

DEA acknowledges that both cost and non-cost factors must be contemplated when determining revenue apportionment and rate design. *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission* provides additional guidance which DEA considered:

> Once revenue requirements have been determined, it remains to decide how and from whom the additional revenue is to be obtained. It is at this point that many counter revealing considerations come into play. The Commission may then

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[33] Ex. 127, Larson Surrebuttal p. 13.

balance factors such as cost of service, ability to pay, tax consequences, and ability to pass on increases in order to achieve a fair and reasonable allocation of the increase among customer classes.[34]

a) Apportionment of Revenue Responsibility to Customer Classes (Disputed Issue #5)

The starting point in determining revenue apportionment to classes is cost as determined under DEA's Class Cost of Service Study. Appropriate weighing of both cost and non-cost factors must result in class revenue responsibility moving closer to the ultimate cost responsibility as determined by the CCOSS.

DEA appropriately weighed cost and non-cost factors in determining inter class revenue apportionment (among classes) and intra class rates (within each class). DEA first decided how much revenue each of its classes will be responsible for, then decided how to design rates within those classes (how much will be a fixed customer charge, demand charge or energy charge) to achieve the desired revenue apportionment.

Dakota Electric initially proposed a revenue apportionment based on the results of the Cooperative's cost of service study.[35] The OAG recommended a revenue apportionment that results in lower increases for residential and small general classes and higher increases for all other classes compared to the proposal of the Cooperative.[36] The Department recommended more modest increases in annual revenue from Small General Service (Schedule 41) than proposed by Dakota Electric by increasing the revenue responsibility from General Service (Schedule 46) slightly more than proposed by Dakota Electric.[37]

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[34] 312 Minn. 250, 260, 251 N.W.2d 350, 357 (1977).
[35] Ex. 101, Larson Direct pp. 7 to 8.
[36] Ex. 200, Nelson Direct p. 32.
[37] Ex. 304, Peirce Direct p. 7.

In prefiled Rebuttal Testimony, Dakota Electric presented cost and revenue comparison information for the Small General Service rate schedule and indicated that the Cooperative would welcome further testimony from the DOC to explore a compromise position between the DEA and DOC revenue apportionment positions.[38]

In prefiled Surrebuttal Testimony, the Department recommended a 3.5 percent annual increase in revenue for Small General Service compared to the 5.15 percent increase proposed in Dakota Electric's initial filing. To offset the revenue responsibility from this change to Small General Service, the DOC recommended a revenue responsibility increase of 0.27 percent to General Service compared to the 0.04 percent increase in revenue responsibility proposed in Dakota Electric's initial filing.[39]

Through the Settlement Agreement, Dakota Electric agreed to the apportionment of revenue responsibility to customer classes contained in the prefiled Surrebuttal Testimony of Department witness Ms. Peirce.[40]

The results of Dakota Electric's CCOSS indicate the amount of increase and decrease in class rate schedule revenue required to align each class with the cost of providing service. The following table summarizes the rate revenue changes indicated by the CCOSS and the proposed revenue apportionment agreed to by DEA and the DOC:

[38] Ex. 126, Larson Rebuttal p. 8.
[39] Ex. 305, Peirce Surrebuttal p. 3.
[40] Ex. 128, Settlement Agreement p. 13.

Class	(A) CCOSS	(B) Proposed
Residential & Farm (31,32,53)	2.85%	2.79%
Small General Service (41)	7.47%	3.50%
Irrigation (36)	2.03%	2.00%
General Service (46,54)	(0.33)%	0.27%
C&I Interruptible (70,71)	2.33%	2.25%
Lighting	1.12%	1.02%

Column A indicates the results of the CCOSS increases and decreases in class rate revenue and Column B indicates the revenue apportionment proposal agreed to in the Settlement Agreement.[41]

The Department and Dakota Electric considered cost and non-cost factors in determining the appropriate revenue apportionment, with a lower apportionment for Small General Service and a slightly higher apportionment for General Service when compared to CCOSS results. Dakota Electric asserts that the Settlement Agreement appropriately weighed these factors, deviated from cost where appropriate, and proposed a reasonably balanced revenue apportionment to classes. Dakota Electric recommends approval of the revenue apportionment compromise reached by DEA and the DOC in the Settlement Agreement.

b) Rate Design (Disputed Issue #6)

All rate design matters were undisputed with the exception of the residential and small general service monthly fixed charges.

Dakota Electric's initial filing proposed a $2.00 increase in the residential monthly fixed charge from the present $8.00 per month to a proposed $10.00 per month. In prefiled Rebuttal and Surrebuttal Testimony, Dakota Electric continued to support a $2.00 per month increase in

[41] Ex. 101, Larson Direct p. 31 and Ex. 305, Peirce Surrebuttal p. 3.

residential monthly fixed charges.[42] The OAG recommends no change in the residential and small general service monthly fixed charge.[43] The Department recommended a $1.00 per month increase in the residential monthly fixed charge from the present $8.00 per month to a proposed $9.00 per month.[44]

Dakota Electric agreed to the Department's proposed $9.00 residential monthly fixed charge in the Settlement Agreement.[45] The Department and Dakota Electric rate design proposal in the Settlement Agreement is consistent with rate making policy and Commission precedent, which provides a moderate and gradual increase that moves this charge closer to cost, provides a reduction in the amount of Intra – Class Subsidy, and creates a rate that more accurately recovers costs.

DEA's CCOSS results found that the "consumer" cost of providing Residential and Farm service is $23.39 and Small General Service is $33.28.[46] Looking in more detail at "consumer" costs, Dakota Electric incurs certain costs (meter, meter reading, billing, transformer, etc.) every month even when a consumer has no consumption. The monthly Fixed Charge seeks to cover these costs separate from volumetric charges.[47] These more direct monthly costs are $11.65 for Residential and Farm service and $18.94 for Small General Service.[48] While the fixed charges proposed by the DOC and DEA remains less than either the results of DEA's fully embedded Cost of Service Study or its analysis of more direct costs, the proposed change is a modest increase that is reasonable and appropriate.

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[42] Ex. 126, Larson Rebuttal p. 36 and Ex. 127, Larson Surrebuttal p. 21.
[43] Ex. 200, Nelson Direct p. 41 and Ex. 202, Nelson Surrebuttal p. 10.
[44] Ex. 304, Peirce Direct p. 23 and Ex. 305, Peirce Surrebuttal p. 11.
[45] Ex. 128, Settlement Agreement p. 14.
[46] Ex. 108, Exhibit DEA-7 in Larson Direct pp. 1 to 2.
[47] Ex. 126, Larson Rebuttal p. 34 and Ex. 127, Larson Surrebuttal pp. 17 to 18.
[48] Ex. 108, Exhibit DEA-7 in Larson Direct pp. 1 to 2.

The Commission recognizes the purpose of a monthly Fixed Charge is "designed to recover fixed costs that do not vary with usage, such as constructing and maintaining infrastructure, reading meters and conducting billing and collection services."[49] While the Commission on one occasion reduced a proposed extraordinary jump in a monthly fixed charge, the Commission has consistently approved reasonable increases in monthly fixed charges, similar to those proposed by DEA.[50]

The monthly Fixed Charge increases proposed by DEA and the DOC more accurately recovers consumer costs through the monthly fixed charge consistent with Minn. Stat. §216B.03 which states in part:

> "Every rate made . . . shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, which shall be sufficient, equitable, and consistent application to a class of customers."

The Commission has consistently supported appropriate adjustments in Customer Charges finding that:

> "The Customer Charge has two main functions, one practical and one grounded in ratemaking policy. Its practical function is to help stabilize utility revenues and reduce the risk that the utility will over or under recover in its revenue requirement due to fluctuations in its usage and sales. Its ratemaking function is to ensure that each customer bears responsibility for a certain level of the Company's fixed costs regardless of usage."[51]

As discussed herein, the proposed adjustment is reasonable, considers the appropriate factors and is consistent with the Commission's past decisions. DEA's monthly Fixed Charge

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[49] *In the Matter of the Application of Otter Tail Power Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket E-017/GR-07-1178, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 72 (August 1, 2008).

[50] *In the Matter of Minnegasco*, Docket No. G-008/GR-95-700, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 52-53 (June 10, 1996) (rejecting a 60% increase, but approving a $1.50 or 30% increase). *See also, In the Matter of the Application of Otter Tail Power Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket E-017/GR-07-1178, ("*2007 Otter Tail Rate Case*"), FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 72 (August 1, 2008) (approval of $1.85 increase to $8.00, for residential customers).

[51] *2007 Otter Tail Rate Case*, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 72 (August 1, 2008).

should be adjusted to $9 for Residential and Farm consumers and $14 for Small General Service consumers.

III. CONCLUSION

DEA is a member-owned not-for-profit electric distribution cooperative governed by a board of directors elected by the ratepayer members that it serves. Based on the testimony of all witnesses and the record in this proceeding, DEA's position on its costs of providing service and rate design reflected in the Settlement Agreement with the DOC are reasonable and well supported by the evidence. As such they should be adopted.

Respectfully submitted,

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