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January 30, 2015

The Honorable LauraSue Schlatter
Office of Administrative Hearings
Administrative Law Division
P.O. Box 64620
St. Paul, MN 55164-0620

RE: In the Matter of the Application by 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
Our File No. 15447.53

Dear Judge Schlatter:

Attached is the Reply Brief and Proposed Findings of Fact, Conclusions and Recommendations of Dakota Electric Association in the above matter, copies of which have been e-served on the parties and individuals on the attached service list.

Yours very truly,

Harold LeVander, Jr.

Hap/sjbg
Enclosures
cc: See Service List

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

STATE OF MINNESOTA)
) SS.
COUNTY OF RAMSEY)

I, Stephanie J. B. Gavin, being duly sworn upon oath, says that on the 30th day of January, 2015, I served the annexed Reply Brief and Proposed Findings of Fact, Conclusions and Recommendations of Dakota Electric Association, on the following persons by electronic service to the persons on the attached service list.

Stephanie J. B. Gavin
Stephanie J. B. Gavin

Subscribed and sworn to before me
this 30th day of January, 2015.

Janice Clark Thomason
Notary Public

Janice Clark Thomason
Notary Public
Minnesota
My Commission Expires January 31, 2017

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BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
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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

REPLY BRIEF OF DAKOTA ELECTRIC ASSOCIATION

January 30, 2015

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Dakota Electric Association ("DEA" or "Cooperative") submits this Reply Brief in response to the Initial Brief of the Office of Attorney General/Residential and Small Business Utilities Division ("OAG").

I. COST OF SERVICE

A. Payroll Expense Adjustment

The OAG recommends disallowing $690,427 of DEA's proposed payroll adjustment for test year 2013 for several reasons. First, OAG contends that this adjustment is not a known and measurable change to the test year. The OAG is wrong. All of the positions for which the adjustment is being sought were existing positions. Fourteen of the seventeen positions were in fact filled by the end of the test year. Thus the annualized compensation for these positions was known and measurable. The new powerline design technician position was filled in 2014. DEA is currently in the process of filling the remaining two positions. Thus, the annualized compensation for these positions was known and measurable. All seventeen positions identified in this exhibit were known in the test year and the compensation for each position was measurable on an annual basis. Accordingly, DEA's payroll adjustment meets the known and measurable test for increases in test year expenses.

OAG contends that DEA's proposed adjustment is inconsistent with the four year downward trend in annualized payroll expenses for the period 2010-2013. The OAG's comparison of test year payroll to the previous four years of payroll ignores current total staffing and payroll, which is the focus of test year expense. Four year averages are not used for other test year expense adjustments.

OAG contends that DEA's description of the reasons why certain positions were vacant for longer than usual periods in 2013 is not the issue.[1] But Mr. Larson's testimony in this regard shows that these vacancies are an issue.[2] It explains why some positions were unfilled for part of the year. This situation was a departure from DEA's normal employment practices, thus making the test year unrepresentative to that extent.

Rates should be set to account for current staffing and service levels to recover the full year's cost of all positions that were not filled during the test year. That is especially true due to the unusual job vacancy circumstances in 2013. The OAG's proposed adjustment of $690,427 would effectively mean that six currently staffed positions would be removed from rate recovery.[3] Common sense dictates that DEA should be allowed to charge rates so that it can pay existing employees their salaries and wages.

B. Subsidiary Support Hours

DEA had substantially reduced the scope of its unregulated subsidiary activities since its last rate case in 2009. In 2010, 23 DEA employees charged 1,197 hours to Energy Alternatives, Inc.(EAI), DEA's wholly-owned subsidiary, for finance, billing, and administrative services. Of these 23 employees, two were hourly and 21 were salaried. Salaried employees at DEA often work more than 40 hours a week.[4]

In 2013, 13 DEA employees charged 355 hours to EAI for finance and administrative services. The difference between the hours spent supporting subsidiary activities by DEA employees in 2010 and 2013 is 842 hours. Significantly, salaried employees who showed a

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[1] OAG Initial Brief, p. 7.
[2] Tr., p. 25 and Ex. 203, at SL-4 (Lee Direct) (DEA Response to OAG IR 803).
[3] Ex. 101, Ex. DEA-1, p. 5 (Larson Direct) ($1,040,494 - $643,269)/($1,040,494* 16 positions = 6.1 positions).
[4] Tr., pp. 40-41.

reduction in hours included DEA's CEO, Vice President of Finance, and Corporate Controller. OAG asserts that the labor costs of $57,700 associated with these 842 hours formerly devoted to subsidiary activities should be eliminated from the cost recovery.

OAG argues that DEA has made no claim that these hours are necessary to perform regulated functions in 2013. [5]OAG is wrong again. DEA would not have included these hours in test year expenses, if it were not claiming that they are necessary for the performance of regulated operations. All of the positions in question are positions of the regulated utility, where the employees devoted some hours to subsidiary activities. Those hours formerly devoted to subsidiary activities are now devoted to regulated utility activities of the affected employees.

OAG notes that DEA claimed at the evidentiary hearings that a majority of the employees who provided labor to EAI in 2010 were salaried employees.[6] That was because DEA was uncertain of OAG's position with respect to the subsidiary hours issue until Ms. Lee's Surrebuttal Testimony.[7] It became clear then that her concern was with the 842 hours no longer devoted to subsidiary activities by DEA employees, rather than the 355 hours still devoted to subsidiary needs by DEA employees. Hence DEA's responsive testimony.

OAG asserts that DEA has not identified any benefit that ratepayers are receiving for these additional costs.[8] These are not additional costs. Rather, they are the embedded costs of regulated utility positions. It should be noted that when the range of subsidiary activities was in its most active stage as in 2010, the regulated utility received the benefit of charges by DEA employees to the subsidiaries.

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[5] OAG Brief, p. 8.
[6] OAG Brief, p. 9.
[7] Ex. 205, pp. 8-9.
[8] OAG Brief, p. 8.

OAG is using data from 2010 to adjust test year expenses. For test year expenses, however, the question is whether they are representative of normalized expenses and whether adjustments should be made to reflect known and measurable changes. What happened in 2010 is not relevant for 2013 test year purposes.

C. Travel and Miscellaneous Expenses

OAG contends that several travel and miscellaneous expenses were unreasonably and imprudently incurred and were unrelated to the provision of electric service. These expenses were $2,066 for a DEA director to campaign for a seat on the CFC Board of Directors (CFC is DEA's primary long-term lender); $672 for excessive airfare for a Board member to attend a conference in Washington, D.C.; $3,909 for food and beverages provided to employees at various company meetings and functions; and $572 for a holiday lunch for Board members and key staff members.[9] The issue of whether these expenses were prudently incurred in the end comes down to the exercise of reasonable business judgment in light of the purposes for which they were incurred. For the reasons stated in its Initial Brief, DEA submits that these expenses were reasonably incurred and were related to the provision of electric service. OAG's opinions show unfamiliarity with DEA's utility operations. If these costs are not recovered from rate payers, there is no separate set of owners or investors from which they can be recovered.

For the first time in its Initial Brief, OAG recommends the denial of reimbursement to Board members for communication services that are ubiquitous to the general public, such as the costs of personal internet, cellular, and date plans.[10] In Exhibit 205, p. 11 (Lee Surrebuttal), however, Ms. Lee stated as follows: "While I did not recommend exclusion of the Board

[9] OAG Brief, pp. 9-10.
[10] OAG Brief, p. 11.

Electronic Reimbursements totaling $17,841, I did have concerns about the reasonableness of these DEA Board member expenses." Furthermore, Ms. Lee testified at the evidentiary hearings as follows: "No, I am not recommending any adjustment."[11] OAG is precluded from raising issues in its Initial Brief that it specifically stated it was not raising in previously filed testimony in the evidentiary hearings.

The DEA Board has the ability to establish appropriate compensation for its directors, and electronic reimbursement is included in that compensation. Board members use electronic communication extensively. This reimbursement helps support a consistent and adequate communication base to accomplish utility functions and communicate with senior management regarding Cooperative operations.

II. REVENUE APPORTIONMENT

One of DEA's stated objectives in its rate filing was to move rates closer to cost. Non-cost factors were also considered in its revenue apportionment and rate design. OAG also recognizes that cost allocation among customer classes influences revenue apportionment.[12] OAG further acknowledges that even with the DOC's modifications to DEA's CCOSS, the revenue apportionment included in the DEA/DOC Settlement Agreement moves all classes closer to the cost of service.

III. COST OF SERVICE STUDY

A. DEA's Minimum Size Method

As stated in its Initial Brief, DEA had used the zero-intercept method of classifying distribution plant costs as either customer or demand related in previous rate cases. OAG was

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[11] Tr., p. 133.
[12] OAG Brief, p. 12.

critical of DEA's use of the zero-intercept method in the 2009 rate case. In its 2010 decision in that rate case, the Commission ordered that DEA use the minimum size method for classifying distribution accounts as either customer or demand related, or provide an analysis to support the outcome of the zero-intercept method. After determining that the zero-intercept method was susceptible to the same concerns raised by the OAG in the 2009 rate case, DEA decided to use the minimum size method in order to comply with the Commission order.

OAG recognizes that the NARUC Manual describes two common methods of conducting a minimum system study: "...the <u>minimum size method used by DEA</u>, and the minimum intercept or 'zero-intercept' method." OAG Initial Brief, p. 15 (emphasis added). While the NARUC Manual states that the minimum size method "generally produces a larger customer component," the Manual also states that the "differences may be relatively small."[13]

DEA followed exactly each step of the minimum size method approach in the NARUC Manual to classify distribution plant costs as either customer or demand related.[14] The weighted average minimum size consumer classification for the four enumerated distribution plant accounts was 61.5%. The weighted average of zero-intercept consumer classification for the four enumerated distribution plant accounts in DEA's 2009 rate case was 57.1%. As the Manual states, the differences between the two methods may be relatively small, which is certainly the case here.

DEA carried the comparative analysis between the two methods one step further. DEA provided a comparison of the cost of service study results using the minimum size and the zero-

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[13] Ex. 311, NARUC Electric Manual at 91, 92.
[14] Ex. 101 (Larson Direct); Work Paper 21, pp. 3-5.

intercept methods.[15] For the Residential and Farm Class, the minimum size method identified a revenue increase of 2.85%, while the zero-intercept method identified a revenue increase of 2.94%. For the Small General Service Class, the minimum size method identified a revenue increase of 7.47%, while the zero-intercept method identified a revenue increase of 7.60%. There was little difference between the methods for Irrigation, General Service, C&I Interruptible, and Lighting Classes. Again, this illustrates the relatively small differences that the two methods produced.

OAG argues that DEA took no steps to recognize that the minimum size method inherently classifies some demand costs as customer costs. OAG suggests that some kind of adjustment be made to a demand allocator to mitigate this result. OAG Brief, p. 18. There is no reason to apply such an adjustment. DEA followed the Commission order from the 2009 rate case to use the minimum size method in the next rate case, unless it could remedy the concerns raised regarding the zero-intercept method. DEA followed the minimum size approach laid out in the NARUC Manual to the letter, which is undisputed by the OAG. The OAG simply objects to the result. DEA has also proved that there is little difference between the results of the two methods, just as the NARUC Manual indicates.[16] There is no reason under these circumstances to apply some further kind of adjustment to a demand allocator as OAG advocates.

OAG contends that there is no basis to compare the weighted averages of customer costs from the minimum size and zero-intercept methods. OAG contends that the results of the two methods produced different results for the individual distribution accounts, sometimes between

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[15] Ex. 101 (Larson Direct); Work Paper 21, p. 4.
[16] Ex. 101 (Larson Direct); Work Paper 21, p. 5.

10 and 20%.[17] DEA conceded this mathematical point, but Work Paper 21, p. 5, demonstrated that the ultimate cost of service study results on a weighted average basis are very similar. It is this composite cost of service result that is the overriding determinant for the customer cost allocation.

Furthermore, there are both pluses and minuses between the two methods. The classification for poles, overhead conductor, and transformers is lower in the minimum size method than in the zero-intercept method. The classification for underground conductor is higher in the minimum size method than in the zero-intercept method. The net differences nearly cancel each other out as demonstrated by the weighted average comparisons.

OAG claims that there are systemic problems with DEA's minimum size method, because it produces a lower apportionment for the residential class than the zero-intercept method used in the 2009 rate case. The OAG ought to applaud that result, since it would lower the cost allocation and revenue apportionment to the residential class. But faced with that reality, the OAG reverses itself and contends that this result demonstrates flaws in DEA's minimum size method.[18] OAG's inconsistent arguments demonstrate the flaws in its analysis, not DEA's. The bottom line from all of this is that DEA's minimum size method developed a customer cost component only slightly higher (61.5%) than its 2009 zero-intercept method (57.1%). The NARUC Manual states that this could likely happen, and it demonstrates that DEA accurately employed the minimum size method in the NARUC Manual in this case.

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[17] OAG Brief, p. 19.
[18] OAG Initial Brief, p. 19.

B. OAG's Zero-Intercept Proxy

OAG contends that its zero-intercept proxy is the proper method to use. OAG even criticizes the minimum size method as laid out in the NARUC Manual. As OAG witness Nelson explains, "...attempting to follow the empirical method described in the NARUC Manual 'leaves the analysis wide open for manipulation' and can lead to meaningless results if the regression model is specified incorrectly or includes errors in data."[19] Even assuming that the OAG statement is true, DEA can hardly be faulted for following the express process described in the NARUC Manual for conducting the minimum size method, without all of the permutations and adjustments which OAG argues should have been used.

OAG's zero-intercept proxy suffers from a major flaw. It omits the material costs of distribution equipment identified in the various plant accounts. OAG asserts that the mathematical justification for OAG's proxy has not been disputed.[20] Nothing could be further from the truth. OAG's analysis excludes the cost of the distribution equipment altogether, considering only the installed cost. Worse yet, it actually subtracts the cost of the equipment from the installed cost of the equipment. It is undeniable, however, that distribution equipment must be in place to connect a customer to the grid. At the evidentiary hearing, witness Nelson acknowledged that the minimum system advocated by the OAG, the zero-intercept proxy, would not be capable of delivering any service to consumers of Dakota Electric.[21]

No wonder the OAG winds up with a weighted customer cost classification of 38%. If the Commission wants to order changes to DEA's minimum system methodology for allocating

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[19] OAG Brief, p. 21.
[20] OAG Brief, p. 21.
[21] Transcript, pp. 99-100.

customer and demand costs, it can do so in the next rate case. The stage has been set in this rate case for using the minimum size method proposed by DEA.

IV. CUSTOMER CHARGE

The DEA/DOC Settlement Agreement adopts the DOC recommendation to increase the customer charge for the residential class from $8.00 to $9.00 ($1.00 increase) and to increase the Small General Service from $10.00 to $14.00 ($4.00 increase).[22] OAG states that this proposal would raise DEA's residential customer service charge to the highest level of any rate regulated Minnesota electric utility.[23] OAG is wrong again. The $9.00 customer charge for the residential class is lower than Xcel Energy's present $10.00 residential charge for underground service. Eight-five percent (85%) of DEA's residential customers receive service through underground facilities. DEA's testimony on this issue is undisputed:

> Dakota Electric's proposed residential monthly fixed charges make progress toward aligning this bill component with the underlying costs in a reasonable time frame – considering our recent history of filing rate cases about every five years. In addition, we note the vast majority (85%) of service to residential customers is provided through underground facilities. Dakota Electric's proposed monthly fixed charge of $10.00 for Schedule 31 compares to the $10.00 monthly charge approved by the Commission for residential underground service for the investor/owned utility in our area.[24]

OAG claims that maintaining a lower customer charge has the overall effect of benefiting low-income customers. Low-income customers are both below and above the average residential consumption level. A lower monthly fixed charge tends to benefit customers with lower than average consumption, while disadvantaging customers with higher than average consumption.

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[22] Ex. 128.
[23] OAG Brief, p. 23.
[24] Exhibit 126, pp. 9-10.

OAG argues that maintaining a lower customer charge promotes conservation by increasing the volumetric charge. The volumetric (energy charge) is still increasing under the rates in the DEA/DOC Settlement Agreement. Customers will always have a lower bill, if they use less electricity.

OAG recognizes DEA's objective that increasing the customer charge will minimize intra-class subsidies. OAG argues that this objective does not overcome the policy benefits of maintaining DEA's customer charge at its current level. OAG claims that DEA and the DOC fail to understand customer costs, which resulted in over-estimating the intra-class subsidy between high-use and low-use residential customers. The OAG is wrong again. DEA's recommendation was based on cost of service study residential customer costs of $11.65, excluding primary line. Even OAG's flawed analysis indicates that these costs are $11.41.[25] Both of these cost benchmarks are below the total residential customer cost of $23.39, including primary line, identified in the cost of service study.

Finally, the OAG contends that DEA and the DOC failed to consider other intra-class subsidies, or that the customer costs produced by the CCOSS are based on an average. OAG's examples in this regard are hypothetical, and the OAG has offered no proof of the potential magnitude of these differences. The bottom line is that the residential customer costs identified in DEA's cost of service study are $23.39. DEA's target for the fixed charge is $11.65. The proposed $9.00 charge is well below either of these costs, and it is lower than Xcel Energy's current $10.00 underground residential basic charge.

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[25] OAG Initial Brief, p. 27.

V. CONCLUSION

The Settlement Agreement entered into between DEA and the DOC in this rate case should be approved, and it should serve as the basis for the Findings of Fact, Conclusion of Law, and Order of the Commission.

Dated: January 30, 2015

Respectfully submitted,

FELHABER, LARSON, FENLON & VOGT, P.A.

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FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
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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

DAKOTA ELECTRIC ASSOCIATION'S

PROPOSED FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATIONS

January 30, 2015

FELHABER, LARSON, FENLON & VOGT, P.A.
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I. INTRODUCTION

An evidentiary hearing was held before Administrative Law Judge LauraSue Schlatter on December 18, 2014, in the Small Hearing Room at the offices of the Minnesota Public Utilities Commission ("MPUC" or "Commission") in St. Paul, Minnesota. The following appearances were made:

Harold LeVander, Jr., attorney at law, Felhaber, Larson, Fenlon & Vogt, P.A., on behalf of the Applicant, Dakota Electric Association ("DEA" or "Cooperative").

Peter Madsen and Linda Jensen, Assistant Attorneys General, on behalf of the Minnesota Department of Commerce - Division of Energy Resources ("DOC" or "Department").

Ryan P. Barlow and Ian Dobson, Assistant Attorneys General, on behalf of the Minnesota Office of the Attorney General – Antitrust and Utilities Division ("OAG").

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Minnesota Public Utilities Commission and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed according to the schedule which the Commission will announce. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions, and Order should be included, and copies thereof shall be served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument.

The Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final order.

Under Minn. Stat. § 14.63, subd. 1, the Commission is required to serve its final decision upon each party and the Administrative Law Judge.

II. FINDINGS OF FACT

A. Jurisdictional-Procedural Background

On July 2, 2014, the Cooperative filed its application, including its Direct Testimony, seeking a general revenue increase of approximately $4,189,000 or 2.1 percent of total revenues (the "Application"), which was assigned Docket No. E-111/GR-14-482 by the Commission. The Cooperative used a historic calendar year with adjustments for known and measurable changes as its test year for this proceeding.

During the course of the proceeding, the parties resolved a number of issues. Dakota Electric and the 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 Cooperative and the Department.[1] This Settlement Agreement was further amended on January 20, 2015. There are remaining disputed issues with the Office of the Attorney General.

1. On August 29, 2014, the Commission issued an Order Accepting Filings and Suspending Rates ("Order Accepting Filing") and a Notice and Order for Hearing. In the Order Accepting Filing, the Commission found that the Cooperative's Application was in proper form

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[1] Ex. 128, Settlement Agreement.

and substantially complete as of July 2, 2014. On August 29, 2014, the Commission also issued its Order Setting Interim Rates authorizing the Cooperative, effective for service rendered on and after September 11, 2014, to collect an interim rate adjustment of 1.5 percent.

2. On October 30, 2014, the DOC and the OAG filed Direct Testimony.

3. On November 20, 2014, Rebuttal Testimony was filed by the Cooperative, the DOC and the OAG.

4. On December 8, 2014, Surrebuttal Testimony was filed by the Cooperative, the DOC and OAG.

B. Summary of Public Comments

5. Judge Schlatter presided at two public hearings to receive comments and questions from non-intervening ratepayers. The first hearing was held in Apple Valley, Minnesota, on the afternoon of December 2, 2014. The other public hearing was held in Farmington, Minnesota, on the evening of December 2, 2014. Five members of the public appeared at the afternoon public hearing and no members of the public appeared at the evening public hearing. Four members of the public spoke at the afternoon public hearing. Three expressed concerns about overall increases in costs, including electric rates. One person indicated that they receive very good service from Dakota Electric and people should expect prices to increase. Representatives of the Commission staff, Office of the Attorney General, Department of Commerce, and the Cooperative attended both hearings.

C. Description of the Cooperative

6. Dakota Electric Association, a Minnesota cooperative association, is an electric distribution cooperative. The Cooperative provides electric service in Dakota County, and portions of Rice, Scott and Goodhue counties, all located in Minnesota.

7. 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 DEA's twelve person board of directors who are also member-owners of DEA. The Board of Directors is elected by DEA's member-owners, which are the same persons as the ratepayers.

8. 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.

9. DEA and other electric distribution cooperatives are not regulated automatically in Minnesota, the cooperative must elect to be regulated for the Commission to have oversight of its rates.[2] DEA has elected to be regulated.

D. Legal Standard, Commission Role and Burden of Proof

10. The Legal Standard for utility rate changes is that rates must be just and reasonable.[3]

11. The Supreme Court has addressed the Commission's role in determining the rates and explained:

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences

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2 Minn. Stat. § 216B.026.

3 Minn. Stat. § 216B.16, subds. 4, 5 and 6

and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[4]

12. In determining whether the burden of proof is met, any doubt as to reasonableness is to be resolved in favor of the consumer.[5] The Commission acts both as a fact finder in weighing evidence that supports facts to be proven by a preponderance of the evidence – legislative capacity on policy issues and in resolving issues consistent with broad public interest.[6]

13. The Supreme Court explained the utilities burden:

> A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. Minn. Stat. § 216B.16, subd. 4 (1986). "Preponderance of the evidence" is defined for ratemaking proceedings as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates." (Citation omitted).

14. After the utility meets its burden, the burden then shifts to the intervenor. For an intervenor to prevail it must provide more than simple statements of doubt or conjecture.[7]

III. RESOLVED ISSUES

A. Financial Issues

Financial issues not in dispute include a) other non-operating income, b) accumulated depreciation expense, c) capitalized payroll expense, and d) cash working capital.

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4 Minn. Stat. § 216B.16, subds. 4, 5, and 6.

5 Minn. Stat. § 216B.03

6 *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 n.W.2d 719, 722-723 (Minn. 1987).

7 Minnesota Practice, Vol. 11, Evidence Section 301.05 at 13.03.

1. **Other Non-Operating Income** (Undisputed Issue #1)

15. Dakota Electric reduced its required net operating income and resulting test year revenue deficiency by including about $399,000 of non-operating income.[8] This non-operating income consists of 1) interest on non-operating margins, 2) subsidiary net income, and 3) other revenue from non-operating margins.[9]

16. In prefiled Direct Testimony, the Department noted that, normally, rate-regulated utilities calculate net operating income and the resulting test year revenue deficiency on a stand-alone basis, which does not include non-utility businesses.[10] Accordingly, the DOC recommended that Dakota Electric's non-operating income of $399,147 be reduced by $272,889 to $116,258.[11]

17. Office of the Attorney General witness Ms. Lee raised several questions related to non-operating income.[12] Dakota Electric provided information on the allocation of patronage capital and the calculation of modified debt service coverage in response to the OAG rebuttal testimony.[13] At the evidentiary hearing Ms. Lee confirmed that the OAG questions were satisfactorily addressed.

18. This issue is no longer in dispute. The parties agree that Dakota Electric's non-operating income of $399,147 should be reduced by $272,889 to $116,258.

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[8] Ex. 101, Larson Direct p. 6.
[9] Ex. 308, Johnson Direct p. 6.
[10] Ex. 308, Johnson Direct p. 7.
[11] Ex. 308, Johnson Direct p. 9 and Ex. 310, Johnson Surrebuttal p. 10.
[12] Ex. 204, Lee Rebuttal pp. 3 to 8.
[13] Ex. 127, Larson Surrebuttal pp. 6 to 10.

2. **Accumulated Depreciation Expense** (Undisputed Issue #2)

19. Dakota Electric proposed an adjustment to normalize its December 2013 depreciation expense for the test year. DEA's proposed adjustment increased test year depreciation expense by $78,749.[14]

20. The Department accepted this depreciation expense adjustment and recommended a corresponding increase in test year accumulated depreciation of $78,749 to reflect the increase in depreciation expense.[15]

21. The OAG initially recommended an increase of $39,375 to accumulated depreciation which is a normalized (annual average) amount for the test year.[16] At the evidentiary hearing Ms. Lee confirmed that since Dakota Electric's test year is based on year-end balances the test year accumulated depreciation should be increased by $78,749.

22. This issue is no longer in dispute. The parties agree that Dakota Electric's test year accumulated depreciation should be increased by $78,749.

3. **Capitalized Payroll Expense** (Undisputed Issue #3)

23. DEA proposed an adjustment to normalize the percentage of payroll that is expensed (as opposed to capitalized) in the test year.[17]

24. The DOC and OAG did not oppose the Cooperative's adjustment to normalize the amount of expensed versus capitalized payroll. However, the Department recommended that DEA record an offsetting entry to rate base for the portion of test-year payroll that was

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[14]Ex. 102, Larson Direct Exhibit DEA-1 p. 2.
[15] Ex. 308, Johnson Direct p. 9.
[16] Ex. 203, Lee Direct pp. 8 to 9.
[17] Ex. 102, Larson Direct Exhibit DEA-1 p. 2.

normalized and expensed on the income statement. The DOC recommended that DEA's test year rate base be reduced by $228,590.[18]

25. Dakota Electric concurred with the Department's recommended adjustment to rate base to reflect the normalization of payroll in rebuttal testimony.[19]

26. This issue was not contested. Dakota Electric agrees to reduce test year rate base by $228,590 to reflect the normalization of expensed versus capitalized payroll.

4. **Cash Working Capital** (Undisputed Issue #4)

27. Dakota Electric incurs costs before consumers pay bills. Cash working capital is the amount of money that DEA needs to have on hand to pay for the costs it incurs to serve its members. The Cooperative applied lead/lag study factors to its test year cash operating expenses to determine its cash working capital requirement of $6,987,282, which was added to its test year rate base.[20]

28. The Department noted that DEA's calculation of cash working capital included test year interest expense, which is included in overall rate of return calculations and not in cash working capital.[21] The Department recommended that the test year cash working capital be reduced by $125,290 for the lead/lag study due to various DOC adjustments including the removal of interest expense.[22]

29. Dakota Electric concurred with the Department's recommended adjustment to cash working capital in rebuttal testimony.[23]

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[18] Ex. 308, Johnson Direct p. 10.
[19] Ex. 126, Larson Rebuttal p. 5.
[20] Ex. 103, Larson Direct Exhibit DEA-2 p. 2.
[21] Ex. 308, Johnson Direct p. 11.
[22] Ex. 308, Johnson Direct p. 11 and Attachment (MAJ-4).
[23] Ex. 126, Larson Rebuttal p. 5.

30. The OAG did not submit testimony on this issue.

31. This issue was not contested. Dakota Electric agrees to reduce cash working capital by $125,290 for the lead/lag study.

B. Rate Base and Rate of Return (Undisputed Issue #5)

32. DEA proposed a total Test Year rate base of $171,613,635 and an overall rate of return on rate base of 6.52 percent.[24]

33. The Department calculated a fair rate of return on common equity capital and a fair overall rate of return for Dakota Electric. The DOC determined that, since the overall rate of return is applied to the rate base to produce the appropriate level of net income, the overall rate of return must be adjusted to allow DEA to earn the same amount on its rate base as it would on its total capitalization.[25] The Department's analysis resulted in an initial recommended overall rate of return of 6.51 percent, which was based on a rate of return on equity for DEA of 4.35 percent, a cost of debt of 5.31 percent, and an overall return on total capital of 4.75 percent.[26]

34. After the evidentiary hearing, the Department discovered a math error in the calculation of its recommended ROE of 4.35%.[27] The Department's recommended ROE should have been the corrected figure of 4.28%. Based upon this corrected figure, the Department would have initially recommended an overall rate of return of 4.71% as applied to total capitalization and 6.47% as applied to the rate base. DEA's cost of debt of 5.31% remains unchanged.[28]

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[24] Ex. 103, Larson Direct Exhibit DEA-2 p. 8.
[25] Ex. 300, Amit Direct p. 19.
[26] Ex. 300, Amit Direct p. 19.
[27] Ex. 128A, Amendment to Settlement Agreement p. 2.
[28] Ex. 128A, Amendment to Settlement Agreement.

35. Dakota Electric concurred with the Department's recommended adjustment to rate base and overall rate of return in the Amended Settlement Agreement.

36. The OAG did not submit testimony on the calculation of overall rate of return.

37. These issues are not contested. Dakota Electric agrees to a rate base of $171,181,006 and overall rate of return of 6.47 percent calculated by the Department.

C. **Energy Sales** (Undisputed Issue #6)

38. Dakota Electric's filing included a weather-normalized energy sales forecast.[29]

39. The Department analyzed Dakota Electric's calculations of test year energy sales volumes and customer counts and recommended that the Commission approve Dakota Electric's energy sales volumes and budgeted customer counts in this proceeding.[30]

40. The OAG did not submit testimony on this issue.

41. The energy sales volumes and customer counts submitted in the Cooperative's initial filing are not contested.

D. **Class Cost of Service Study** (Undisputed Issue #7)

42. 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.[31] The first modification is use of the minimum-size method to determine the relative amount of specified distribution accounts to classify as

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[29] Ex. 122, Larson Direct Workpaper 13.
[30] Ex. 306, Zajicek Direct p. 8.
[31] Ex. 101, Larson Direct p. 20 and Ex. 104, Larson Direct Exhibit DEA-3.

"consumer" costs.[32] The second modification was the inclusion of a new wholesale power energy charge.[33]

43. The DOC and OAG evaluated Dakota Electric's class cost of service study (CCOSS).

44. The Department concluded that Dakota Electric's proposed CCOSS is reasonable. The classification and allocation of the functionalized accounts are generally consistent with the 1992 Electric Utility Cost Allocation Manual by the National Association of Regulatory Utility Commissioners (NARUC), and Dakota Electric has made relevant updates to its input data.[34] Based on these conclusions, the Department recommended that the Commission adopt Dakota Electric's proposed class cost of service study.[35]

45. 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.[36] The OAG did not contest the Cooperative's class cost of service study, exclusive of the minimum-size method.

46. Dakota Electric's class cost of service study, exclusive of the minimum-size methodology, is not contested.

E. **Rate Design** (Undisputed Issue #8)

47. Dakota Electric proposed many rate design changes as described in the prefiled Direct Testimony of Mr. Larson at Pages 38 through 58.

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[32] Ex. 101, Larson Direct p. 21 and Ex. 125, Larson Direct Workpaper 21.
[33] Ex. 101, Larson Direct p. 21.
[34] Ex. 301, Ruzycki Direct p. 14.
[35] Ex. 301, Ruzycki Direct p. 15 and Ex. 302, Ruzycki Rebuttal p. 7 and Ex. 303, Ruzycki Surrebuttal p. 8.
[36] Ex. 200, Nelson Direct p. 16 and Ex. 201, Nelson Rebuttal pp. 4 to 5 and Ex. 202, Nelson Surrebuttal p. 10.

48. The Department reviewed the rate design recommendations proposed by Dakota Electric. Rate design issues evaluated by the DOC included customer charges, residential time-of-day (TOD) tariffs, geothermal heat pump, line extension charges, and service and reconnection charges. Regarding these matters, the DOC summarized its recommendations as follows:[37]

- Approve the following monthly customer charges:
  - Residential - $9.00
  - Residential (Demand Control) - $12.00
  - Residential (TOD) - $12.00
  - Residential (New TOD) - $12.00
  - Small General Service - $14.00
  - Irrigation - $30.00
  - General Service - $34.00
  - General Service (TOD) - $36.00
  - Commercial & Industrial Interruptible - $110.00
- Approve DEA's proposed Schedule 55 Residential Time-of-Day Tariff, and rate changes to its Schedule 53 Residential Time-of-Day Tariff.
- Approve DEA's request to close its Geothermal Heat Pump Service to new customers.
- Approve the proposed Line Extension Charges.
- Approve the proposed Service and Reconnection Charges.

49. The only <u>disputed</u> rate design matter is the residential and small general service monthly fixed charge. The OAG did not contest the Cooperative's other rate design proposals.

50. Dakota Electric's rate design proposals, exclusive of the residential and small general service monthly fixed charge, are not contested.

F. Matching Power Cost Revenue and Expense (Undisputed Issue #9)

51. The Commission's August 29, 2014 Notice and Order for Hearing includes the following language on Page 2:

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[37] Ex. 304, Peirce Direct p. 23.

> The Commission also asks the parties to address and provide schedules and supporting documentation in the development of the record in this matter, that show the matching of power cost revenue to power cost expense in the pro forma test year financial schedules.

52. Based on a continuing discussion of this matter through information requests and a meeting with all parties and Commission Staff, Dakota Electric prepared an updated response to Department information request 505 which was identified as "DEA Surrebuttal Exhibit 3."[38] This updated response resolved a few matters. First, Dakota Electric proposed to revise the Power Cost Adjustment (PCA) base that is applied to firm service rate schedules as shown in this exhibit. The net change in the PCA base is an increase from $0.0899 per kWh to $0.0903 per kWh.[39] Second, the calculation of tariffed revenue under present and proposed rates, and resulting identification of tariffed revenue associated with wholesale power service from GRE and distribution service, includes a component that recognizes about $285,000 in the current cost of power for various carry-over/true-up amounts in the Cooperative's present Resource and Tax Adjustment (RTA). These amounts will be trued-up as Dakota Electric's RTA transitions from present rates to proposed rates. Together, these updates result in the calculated tariff revenue associated with wholesale power nearly equaling the wholesale power costs included in the test year.[40]

53. The Department concurred with the revised PCA base and explanation of the matching of power cost revenue and expense in the Settlement Agreement.

54. The OAG did not submit testimony on this issue.

55. Dakota Electric's revised PCA base and explanation of the matching of power cost revenue and expense were not contested.

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[38] Ex. 127, Larson Surrebuttal p. 19.
[39] Ex. 127, Larson Surrebuttal p. 19.
[40] Ex. 127, Larson Surrebuttal p. 19.

IV. DISPUTED ISSUES

A. 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.

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

56. 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.[41]

57. 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.[42]

58. 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 help design lending

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[41] Ex. 203, Lee Direct pp. 12 – 14 and Ex. 205, Lee Surrebuttal p. 13.
[42] Ex. 126, Larson Rebuttal pp. 36 – 37 and Ex. 127, Larson Surrebuttal p. 21.

policies directly related to the provision of electric service and should be included as an expense in the test year.[43]

59. The airfare in question was secured days before the event, when it was determined that DEA did not have anyone attending this conference.[44] 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.

60. Dakota Electric provided detailed expense documentation on the various food expenses.[45] 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.

61. 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.

62. These travel and miscellaneous expenses were all legitimate costs of doing the administrative business necessary to provide electric service and should be included in the test year for rate recovery.

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[43] Ex. 126, Larson Rebuttal pp. 16-17.
[44] Ex. 126, Larson Rebuttal p. 17.
[45] Ex. 205, Lee Surrebuttal (OAG Information Request 806, attached as Schedule SL-15).

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

63. 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.[46]

64. 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.[47] The positions identified for the compensation adjustment are existing positions.[48] Disallowing this annualization adjustment has the net effect of removing from rate recovery the compensation and benefits of six existing Dakota Electric positions.[49] Additionally, the Powerline Design Technician position was filled by mid-2014 as reflected in the annualization adjustment.[50]

65. 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.[51] These unusual events tend to distort the job vacancy data beyond the normal employee turnover.

66. 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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[46] Ex. 203, Lee Direct pp. 5 – 7 and Ex. 205, Lee Surrebuttal p. 13.
[47] Ex. 126, Larson Rebuttal p. 36 and Ex. 127, Larson Surrebuttal p. 21.
[48] Ex. 126, Larson Rebuttal p. 13.
[49] Ex. 102, Exhibit DEA-1 of Larson Direct p. 5 (($1,040,494 - $643,269)/$1,040,494)*16 positions = 6.1 positions
[50] Ex. 203, Lee Direct at SL-4 (DEA response to OAG IR 803).
[51] Tr. p. 25 and Ex. 203, Lee Direct at SL-4 (DEA response to OAG IR 803).

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

67. 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.[52]

68. 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.[53] 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.

69. Since 2010, changes have been made to the responsibilities of various positions that may have previously charged time to subsidiaries.[54] 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. All labor costs associated with the identified 842 hours should be included in the test year and recovered through rates.

B. **Class Cost of Service Study** (Disputed Issue #4)

70. 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 objective of performing a CCOSS is to measure, as closely as possible, the cost

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[52] Ex. 203, Lee Direct p. 8 and Ex. 205, Lee Surrebuttal p. 13.
[53] Tr., p. 40.
[54] Tr., p. 41.

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.

71. 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.[55]

72. Beyond 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.[56] Cost allocation is based on factors that reflect cost causative drivers for the expenses being allocated.

73. 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.[57] The first modification is use of the minimum-size method to determine the relative amount of specified distribution accounts to classify as "consumer" costs.[58] The second modification was the inclusion of a new wholesale power energy charge.[59]

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[55] Ex. 104, Exhibit DEA-3 of Larson Direct p. 2.
[56] Ex. 101, Larson Direct p. 20.
[57] Ex. 101, Larson Direct p. 20 and Ex. 104, Exhibit DEA-3 of Larson Direct.
[58] Ex. 101, Larson Direct p. 21 and Ex. 125, Workpaper 21.
[59] Ex. 101, Larson Direct p. 21.

74. 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.[60]

75. 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.[61]

76. 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.[62]

77. The single issue in dispute regarding Dakota Electric's CCOSS is the appropriate methodology to use for the classification of certain distribution plant accounts.

78. 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.

79. 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."

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[60] Ex. 301, Ruzycki Direct p. 15; Ex. 302, Ruzycki Rebuttal p. 7; and Ex. 303, Ruzycki Surrebuttal p. 8.
[61] Ex. 200, Nelson Direct p. 16; Ex. 201, Nelson Rebuttal pp. 4 to 5; and Ex. 202, Nelson Surrebuttal p. 10.
[62] Ex. 200, Nelson Direct p. 20 and Ex. 202, Nelson Surrebuttal p. 10.

80. Since DEA determined that the same concerns with the zero-intercept pointed out by the 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.

81. 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.[63]

82. 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.

83. 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.[64]

84. 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 assertion that the cheapest distribution equipment should be used for a minimum system analysis is also not consistent with

[63] Ex. 101, Larson Direct p. 21.
[64] Ex. 126, Larson Rebuttal pp. 22 to 23 and Ex. 127, Larson Surrebuttal pp. 11 to 12.

the direction provided in the NARUC Manual.[65] The OAG analysis is also performed using installation costs for plant installed over a 30 to 40 year time frame.[66]

85. 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.

86. 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).

87. 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.[67]

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[65] Ex. 126, Larson Rebuttal p. 28.
[66] Ex. 127, Larson Surrebuttal p. 13.
[67] Ex. 127, Larson Surrebuttal pp. 12 to 13.

88. DEA made a reasonable decision to switch to the use of the minimum-size method to avoid the concerns with the zero-intercept method.

89. 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.

90. The OAG proposed alternative method produces a weighted customer 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.

91. 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.

92. 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.[68]

93. DEA's CCOSS, including application of the minimum-size method, should be approved.

C. Revenue Apportionment and Rate Design

94. 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

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

> 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.

95. 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 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.[69]

1. Apportionment of Revenue Responsibility (Disputed Issue #5)

96. The starting point in determining revenue apportionment to classes is cost as determined under DEA's Class Cost of Service Study.

97. 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.

98. 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.[70]

99. 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

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[69] 312 Minn. 250, 260, 251 N.W.2d 350, 357 (1977).
[70] Ex. 128, Settlement Agreement p. 13.

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:

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%

100. 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.

101. The Settlement Agreement appropriately weighed these factors, deviated from cost where appropriate, and proposed a reasonably balanced revenue apportionment to classes.

102. The revenue apportionment compromise reached by DEA and the DOC in the Settlement Agreement should be approved.

2. **Rate Design** (Disputed Issue #6)

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

104. Dakota Electric agreed to the Department's proposed $9.00 residential monthly fixed charge in the Settlement Agreement.[71]

105. The Department and Dakota Electric rate design proposal in the Settlement Agreement is consistent with rate making policy and Commission precedent, which provides a

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[71] Ex. 128, Settlement Agreement p. 14.

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.

106. 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.[72]

107. 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, identified as $11.65 for Residential and Farm service and $18.94 for Small General Service, separate from volumetric charges.[73]

108. 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 the more direct costs, the proposed change is an increase that is reasonable and appropriate.

109. 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."[74]

110. 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."

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[72] Ex. 108, Exhibit DEA-7 in Larson Direct pp. 1 to 2.
[73] Ex. 126, Larson Rebuttal p. 34 and Ex. 127, Larson Surrebuttal pp. 17 to 18.
[74] *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).

111. 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."[75]

112. The proposed adjustment is reasonable, considers the appropriate factors and is consistent with the Commission's past decisions. DEA's monthly Fixed Charge should be adjusted to $9 for Residential and Farm consumers and $14 for Small General Service consumers.

V. 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.

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. Ch. 216B and section 14.50.

2. Any foregoing Finding which contains material which should be treated as a Conclusion is hereby adopted as a Conclusion.

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[75] *2007 Otter Tail Rate Case*, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 72 (August 1, 2008).

3. Each Resolved Issue has been resolved in a reasonable manner, is consistent with the record, and should be approved as recommended by the Parties.

4. DEA should be granted an increase in revenues of $4,189,232.

5. Proposed changes in rate design and tariff provisions as reflected in the Settlement Agreement between DEA and the DOC are reasonable and should be approved.

Respectfully submitted,

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