MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**December 11, 2025**		**Agenda Item 1***
Company	Dakota Electric Association		
Docket No.	E-111/GR-24-400		
	In the Matter of the Application by Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota		
Issues	Should the Commission adopt the recommendations in the ALJ's Report?		
Staff	Godwin Ubani	godwin.ubani@state.mn.us	651-206-2191
	Jason Bonnett	Jason.bonnett@state.mn.us	651-201-2235
	Andrew Larson	Andrew.larson@state.mn.us	651-201-2259
	Eric Willette	Eric.r.willette@state.mn.us	651-201-2227

✓ **Relevant Documents**	**Date**
Dakota Electric Association – Settlement	June 6, 2025
Dakota Electric Association – Proposed Findings of Fact, Conclusions of Law, And Recommendation to Approve Settlement	August 13, 2025
Dakota Electric Association – Appendix B to Proposed Finding of Fact – Summary of Public Comments	August 15, 2025
ALJ Report	
Stipulated Findings of Fact, Conclusions of Law and Recommendation to Approve Settlement	October 16, 2025
ALJ Report – Appendix A	October 16, 2025

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The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

✓ **Relevant Documents**	**Date**
Support For ALJ Report	
Minnesota Office of Attorney General – Residential Utilities Division - Letter	October 30, 2025
Minnesota Department of Commerce, Division of Energy Resources – Letter	October 31, 2025
Dakota Electric Association – Letter	October 31, 2025

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I. INTRODUCTION

Dakota Electric Association (Dakota Electric, DEA, or the Company) was founded in 1937 as a non-profit, member-owned electric distribution only utility that serves approximately 115,000 customers (members) in Dakota County and portions of Scott, Rice, and Goodhue Counties in Minnesota. The Company has projected total annual electricity sales of 1,872,343,646 kWh.[1]

DEA does not generate electricity nor own any high voltage transmission lines. Instead, it purchases wholesale power and related transmission services from Great River Energy (GRE) in Maple Grove, Minnesota.[2] The Company has a 12-person elected board of directors made up of members that governs the Cooperative and it is also the only Commission rate-regulated electric cooperative in Minnesota.[3]

On October 16, 2025, the Administrative Law Judge (ALJ) Anne C. O'Reilly issued her Stipulated Finding of Fact, Conclusions, and Recommendation to Approve Settlement (ALJ Report). If the Commission approves the ALJ Report, Dakota Electric's requested $23.8 million, or 11.0 percent, annual increase based on a rate of return on rate base of 5.30 percent would be reduced to $20.9 million, or 9.6 percent.

The main issue before the Commission is whether to accept and adopt the ALJ Report (and Recommendations).

If the Commission does not accept the ALJ's Report (and recommendations) in its entirety, then based on Commission modifications, it would need to determine the Company's appropriate test year revenue amount and how that revenue amount would be collected from customers.

II. BACKGROUND

On December 30, 2024, Dakota Electric filed a general rate case petition with Minnesota Public Utilities Commission (Commission) (Docket No. E-111/GR-24-400), together with supporting testimony, schedules, and workpapers requesting authority to increase rates for electric service in Minnesota effective January 1, 2024. Dakota Electric requested a $23.8 million, or 11.0 percent, annual increase based on a rate of return on rate base of 5.30 percent. Dakota Electric's 2024 revenue requirements are based on historical calendar test-year 2023, adjusted for known measurable changes and a proposed rate of return on total equity capitalization of 5.30 percent. The Company requested that if the Commission suspends its proposed rates, then the Commission should approve $20.4 million, or 9.5 percent, interim rate increase and be made effective March 1, 2025.

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[1] DEA Ex.1 at Workpaper 12.

[2] ALJ Report Finding of Fact N0. 2.

[3] Id.

On February 18, 2025, the Commission issued a series of orders[4]in this case, including an Order Accepting Filing, Suspending the proposed final Rates, and Extending Timeline; an Order Setting Interim Rates increase of $20.5 million, or approximately 9.5 percent, effective March 1, 2025; and a Notice of and Order for Contested Case Hearing. Administrative Law Judge Ann C. O'Reilly of Minnesota Court of Administrative Hearing (CAH) was assigned to conduct the case.

There are three parties to this case, namely Dakota Electric Association, Minnesota Department of Commerce-Division of Energy Resources (the Department) and Minnesota Office of the Attorney General-Residential Utilities Division (OAG). The Parties submitted prefiled testimony in advance of the evidentiary hearings. (Copies of the prefiled testimony are available electronically through the eDockets system).

On February 24, 2024, the ALJ held a prehearing status and scheduling conference[5] and on February 25, 2025 the ALJ issued a Stipulated Protective Order.[6]

On February 27, 2025, the ALJ issued a First Prehearing Order that set forth the timeline and process for the proceeding.[7]

On May 6, 2025, the ALJ Judge conducted one virtual public hearing, where Members of the public were able to join the virtual public hearing via an internet or telephone connection.

On May 7, 2025, the ALJ held in-person public hearings in Apple Valley and Rosemount, Minnesota with all attendance as follows:

Table 1: Summary of Public Hearings

Date &Time	Type of Hearing	Location	Public Member-Number in Attendance	Public Member-Number that Spoke
5/6/2025 -6PM	Virtual -Webex	Virtual - Webex	2	2
5/7/2025 -1PM	In-Person	Senior & Event Ctr, Apple Valley, Minnesota	12	8
5/7/2025 – 6PM	In-Person	Community Ctr. Rosemount, Minnesota	6	4

[4] ORDER ACCEPTING FILING AND SUSPENDING RATES; NOTICE AND ORDER FOR HEARING; and ORDER SETTING INTERIM RATES (this docket – E-111/GR-24-400).

[5] ORDER FOR PREHEARING CONFERENCE (Feb. 18, 2025)

[6] ALJ Report Findings of Fact N0.10.

[7] Id.

Apart from the virtual and in-person public hearings, there were a total of twenty-six written comments to the ALJ and the Commission combined. A majority of the comments opposed a rate increase or recommended a lower increase. Commenters shared concerns about Dakota Electric's Board of Director's expenses including the disclosure of those expenses. Written comments called the rate increase "excessive,"[8] and shared concerns about how customers were not benefiting from the additional revenue from the proposed increase. Two commenters acknowledged the Cooperative is facing rising costs and that rate increases are "occasionally necessary.[9] Some of the customers' written comments also stated concerns around the Cooperative's transparency regarding the proposed rate increase. Four commenters shared their concern about the burden placed on low-income customers and customers living on fixed incomes, including social security.[10] One commenter shared that he felt the Cooperative was asking middle-class users to accept a rate hike that exceeds both their annual wage increases and the general rise in living expenses.[11] Commenters also voiced concern about customers' lack of flexibility around energy use during peak periods. Some commenters questioned the Cooperative's justification for the increase. Others suggested ways to improve communications to members to improve transparency. Further, three comments raised concerns about the mathematics, formulas, and the accuracy of what was shared with customers.[12] One commenter felt that investments in energy efficiency measures did not result in customer energy savings on bills.

On June 6, 2025, Dakota Electric filed with the ALJ a comprehensive and unanimous Settlement Agreement, along with supporting attachments, entered into between the Company, the Department of Commerce, and the Office of the Attorney General resolving all issues among all parties in the instant case.

Normally when all parties to a utility rate case reach a settlement, the Administrative Law Judge must present the settlement to the Commission for its consideration. Accordingly, the Administrative Law Judge cancelled the evidentiary hearing and excused the Parties from any further filings and returns this proceeding to the Commission together with her recommendation to approve the Settlement**.**

Thus, on June 10, 2025, the ALJ issued its Second Prehearing Order, following the parties June 6, 2025, filing of a Settlement Agreement, based upon the Settlement Agreement and the request of the parties ALJ ordered that:

- The deadlines for Rebuttal Testimony, Surrebuttal Testimony, and Witness Summaries as set forth in the First Prehearing Order are VACATED.

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[8] ALJ Report Findings of Fact No. 77, at 12.

[9] Id.

[10] Id., at 13.

[11] Id.

[12] Id.

- The Second Prehearing and Settlement Conference Schedule for June 23, 2025, is CANCELLED.

- The Evidentiary Hearing scheduled for June 26, 2025, is CANCELLED.

- On or before August 13, 2025, the Parties will submit joint proposed findings of fact, conclusions of law, and a recommendation detailing the issues in the case and the proposed settlement of those issues. The Parties will not be submitting Initial or Reply Briefs, or an Issue Matrix.

- The parties will stipulate to a Master Exhibit List which contains the complete record of the evidence for the Administrative Law Judge and Commission to consider as part of the settlement agreement. The Parties will file the stipulated Master Exhibit List in eDockets on or before June 23, 2025, and will email a courtesy copy in Word format to the Administrative Law Judge.

- The Administrative Law Judge will prepare Findings of Fact, Conclusions of Law, and a Recommendation (Report) for the Commission. The Report will be filed on or before November 3, 3025.

On June 20, 2025, Dakota Electric, the Department of Commerce, and the Office of the Attorney General filed the Joint Stipulated Master Exhibit List in accordance with the June 10, 2025 Second Prehearing Order.

On August 13, 2025, Dakota Electric, the Department of Commerce, and the Office of the Attorney General filed the Joint Proposed Findings of Fact, Conclusions of Law, and Recommendation in accordance with the June 10, 2025 Second Prehearing Order.

Also, the Dakota Electric, the Department of Commerce, and the Office of the Attorney General filed on August 15, 2025, Appendix B to the Joint Proposed Findings of Fact, Conclusions of Law, and Recommendation, that represent a Summary of Public Comments.

On October 16, 2025, ALJ O'Reilly issued her Stipulated Findings of Fact, Conclusions of Law, and Recommendations to Approve Settlement (ALJ Report) and Appendix A.

Issues Set for Hearing

The Commission in its February 18, 2025 Notice and Order for Hearing, the Commission identified the following issues for the parties to address in this proceeding:

1. Whether the test year revenue increase sought by Dakota Electric is reasonable or will result in unreasonable or excessive earnings.
2. Whether the rate design proposed by Dakota Electric is reasonable.
3. Whether Dakota Electric's proposed capital structure and return on equity (ROE) are

reasonable.

4. Whether the proposed capital structure or an alternate capital structure should be adopted.
5. The reasons for the significant cost changes of the following costs since Dakota Electric's last rate case (2019):

    - Distribution-Maintenance expense increase of 23.6%;
    - Administrative & General expense increase of 36.3%;
    - Depreciation & Amortization expense increase of 31.8%;
    - Other Interest Expense increase of 85.9%; and
    - Other Deductions increase of 113.8%.

Staff is of the opinion that these items have been adequately addressed in this proceeding.

III. ALJ Report

The Settlement resolved all issues between all parties which, if approved, would result in a revenue increase of $20.9 million, or 9.6%. On October 16, 2025, Judge O'Reilly issued her ALJ Report recommending approval of the Settlement:

> 34. As detailed in the Settlement, the Parties were able to resolve all issues in the case. The Settlement summarizes the Parties' positions on each of their applicable issues and explains each issue's resolution. The Settlement needs little explanation, as reviewing the Parties' positions and comparing party positions to the terms of the Settlement indicates the compromises that the Parties made to achieve an overall Settlement.
>
> 35. The Administrative Law Judge has reviewed the Settlement and recommends that the Commission find it to be in the public interest and supported by substantial evidence in the record. The rates that will result from implementing the Settlement will be just and reasonable.
>
> 36. The Administrative Law Judge finds the Settlement to be comprehensive and each disputed issue is reasonably resolved based on substantial record evidence. The Administrative Law Judge recommends that the Commission approve the Settlement and highlights the following factors for the Commission's consideration.
>
> 37. First, the Settlement provides for a gross revenue deficiency of $20.881 million or 9.62% increase, compared to the $23.812 million or 11% increase requested in the Cooperative's Application.

The ALJ noted that the Settlement had provisions for confidentiality of negotiations and offers, and that it holds that, should it be rejected, it is no longer part of the record.[13] The Settlement

[13] ALJ Report ¶ 53.

requires all parties to support and defend it in its entirety without modification.[14]

IV. SUPPORT FOR THE ALJ REPORT

The Department, the OAG, and Dakota Electric took no exception to the ALJ Report.

A. Department of Commerce

On October 31, 2025, the Department submitted its letter of support to ALJ O'Reilly's report and implored the Commission approve the settlement agreement achieved by the settling parties. The ALJ report confirms that the parties settlement agreement is consistent with public interest and supported by substantial evidence.

Further the Department noted:

> The settlement provides substantial value to Dakota Electric Association's members. The settlement limits the Association's overall revenue requirement increase to $20.881 million, representing an average 9.62% increase. This increase is smaller than the 11% increase requested in the Association's initial filing. The return on equity, overall cost of capital, and overall return on rate base reflect the Department's proposed adjustments to the calculation of the Association's capital structure. As part of settlement discussions, the Association provided the parties with additional support for its test year compensation expense. This additional information allowed the parties to reach agreement on more accurate test year compensation expense adjustments than would have been possible based on the initial filing.

The Department also reviewed DEA's financial schedules as part of the settlement and found no issues that would require the Commission attention at this time and therefore recommend their approval by the Commission.

B. OAG

As party to the Settlement Agreement, the OAG filed a letter of support to the ALJ's conclusion in her report that the record supports the settlement's resolution of all disputed issues and therefore recommended the Commission adopt the ALJ's Report. Further, the OAG stated in its letter of support of the ALJ' report:

> Importantly, the settlement provides financial benefits to Minnesota's residential and small-business ratepayers. The settlement provides for a smaller increase than requested by Dakota Electric Association, reducing the Association's revenue deficiency by approximately $2.93 million from its

[14] Settlement at 23.

initial request.[15] The settlement allocates a smaller share of the overall increase to the Residential class than originally proposed and a reduced fixed charge, which is important given concerns from public commentors about the size of the proposed Residential increase noted in the ALJ Report. For these reasons and others detailed in full in the settlement, the settlement is reasonable, supported by substantial evidence, and consistent with the public interest. The Commission should accept the settlement.[16]

C. Dakota Electric

On October 30, 2025, Dakota Electric submitted its letter of support and agreed with the ALJ's conclusions that the record supports the resolution of disputed issues as set out in the Settlement, and that the Settlement's disposition of disputed issues resolved them in a manner consistent with the public interest and on the basis of the substantial evidence. Therefore, the Company urged the Commission to adopt the ALJ Report.

V. FINANCIAL ISSUES

A. Employee Compensation

PUC Staff: Eric Willette

1. Parties Positions

Dakota Electric, in its initial filing, proposed recovery of $12,683,503 in test year salary expense and $545,709 in test year other pay expense. Dakota Electric based salary expense on an annual cost of living increase and new positions that will be added at market competitive salaries. Other pay expense is based on 2023 actuals and is consistent with historical trends.
In Direct, the Department recommended reducing salary and other pay expense by $1.59 million. The Department calculated the reduction by using 2022 actual salaries and other pay with a 5% inflator applied over two years and removal of $125,000 of salary expense for Operations and Safety Specialist position Dakota Electric no longer planned on filling as noted in response to Department Information No. 121. The proposed reductions results in salary expense of $11,319,171 and other pay expense of $318,659.

In Direct, the OAG recommended removing all employee award and gift expense, except for those related to safety and trainings. This recommendation is based on Dakota Electric not providing support that the costs were necessary for utility service. The OAG recommended reducing other pay expense by $88,656 and removing $28,250 for year-of-service awards.

2. Resolution

Parties agreed to reduced revenue requirement by $700,000 for expensed payroll, reflecting

[15] Settlement Agreement, Attach. 1 (June 6, 2025)

[16] OAG Letter, p. 1.

the Department's recommended adjustment, for a total test year payroll expense of $11,983,503. For other pay, parties agreed to reduce test year other pay by a total of $243,453, to reflect the Department's recommendation and a removal of test-year holiday gift and year-of-service awards, based on OAG's recommendations.

3. Decision Options

101. Approve Dakota Electric salary expense of $11,983,503 for test-year. (Department, OAG, Dakota Electric, ALJ)

102. Disallow Dakota Electric other pay expense of $243,453 for test-year. (Department, OAG, Dakota Electric, ALJ)

103. Approve Dakota Electric salary expense of $12,683,503 for test-year. (Dakota Electric Initial Filing, ALJ)

104. Approve Dakota Electric other pay expense of $545,709 for test-year. (Dakota Electric Initial Filing, ALJ)

B. Employee Awards and Gifts

PUC Staff: Eric Willette

1. Parties Positions

Dakota Electric, in its initial filing, included schedules separately itemizing all travel, entertainment, and other related employee expenses as required by Minn. Stat. § 216B.16, subd. 17. In Revised Volume 2 Workpaper 15H, Dakota Electric submitted a total $65,063 in employee functions and awards.

In Direct, the OAG recommended a reduction to recreation and entertainment costs identified in Workpaper 15H to eliminate all expenses not related to safety and department-wide trainings in the amount of $23,539. The OAG also recommended removing $49,472 in employee appreciation gifts, celebrations for holidays and new employee welcome lunches which were identified in Workpaper 15G.

2. Resolution

Parties agreed to remove $23,539 and $49,472 as recommended by the OAG.

3. Decision Options

105. Disallow Dakota Electric recovery of $23,539 in recreation and entertainment expense. (OAG, Dakota Electric, ALJ)

106. Disallow Dakota Electric recovery of $45,472 in employee appreciation gifts, celebrations, and new employee welcome lunches expense. (OAG, Dakota Electric, ALJ)

107. Allow Dakota Electric to recovery recreation, entertainment, employee appreciation gifts, celebrations and new employee welcome lunch expense as initially filed. (Dakota Electric Initial Filing)

C. Payroll Taxes

PUC Staff: Eric Willette

1. Parties Positions

In response to discovery issued by the Department, Dakota Electric explained that it discovered that the 2023 test year included capitalized portions of FICA taxes of $257,249. In Direct, the Department recommended that FICA taxes be reduced by $257,249 to reflect removal of this capitalized amount, reducing test year payroll taxes from $1,697,832 to $1,440,583.

2. Resolution

Parties agreed to accept the Departments recommendation.

3. Decision Options

108. Disallow recovery of $257,249 in payroll taxes for test year. (The Department, Dakota Electric, ALJ)

109. Allow Dakota Electric to recover test year payroll taxes of $1,697,832. (Dakota Electric Initial Filing)

D. Benefits

PUC Staff: Eric Willette

1. Parties Positions

Dakota Electric, in its initial filing, proposed recovery of employee benefits including life insurance, workers' compensation, pension, and post-employment 106 benefits based on 2023 actual expenses and adjusted based on planned staffing changes.

In Direct, the Department concluded that life insurance, workers' compensation, post-employment 106 benefits and pension expenses were overestimated based on historical averages. The Department recommended reducing 2023 test year life insurance, workers' compensation, pension, and post-employment 106 based on the four-year average of actual

expense (2021-2024) on a per FTE basis with a 5% inflator multiplied by the number of FTE proposed in the test year. The Department proposed reducing:

- Life insurance from $129,577 to $80,788
- Workers' Compensation from $146,726 to $71,131
- Post-Employment 106 Benefit from $148,634 to $28,580
- Pension Expense from $1,564,618 to $1,449,523

2. Resolution

Parties agreed to reduce each benefit by the amounts below:

- Life insurance $48,788
- Workers' Compensation $45,000
- Post-Employment 106 Benefit $85,000
- Pension Expense $115,095

3. Decision Options

110. Disallow recovery of benefits in the amounts of Life insurance $48,788, Workers' Compensation $45,000, Post-Employment 106 Benefit $85,000, and Pension Expense $115,095 (The Department, Dakota Electric, ALJ)

111. Allow Dakota Electric to recover employee benefits as initially filed. (Dakota Electric Initial Filing)

E. Utility Service Revenue

PUC Staff: Eric Willette

1. Parties Positions

Dakota Electric, in its initial filing, included $329,651 for 2023 test year utility service revenue based on actuals.

In Direct, the Department noticed utility service revenues were lower in the test year when compared to 2022 and 2024. The Department recommended using a three-year average of 2022-2024 actual revenues which is $418,199. That would increase utility service revenue by $88,548.

2. Resolution

Parties agreed to increase test year utility service revenue by $70,000.

3. Decision Option

112. Require Dakota Electric to increase utility service revenue by $70,000. (The Department, Dakota Electric, ALJ)

113. Allow Dakota Electric to use initial amount for utility service revenue. (Dakota Electric Initial Filing, ALJ)

F. Charges and Fees Revenue

PUC Staff: Eric Willette

1. Parties Position

Dakota Electric, in its initial filing, included $890,555 for 2023 test year charges and fees revenue based on actuals.

In Direct, the Department noticed charges and fees revenues were lower in the test year when compared to 2022 and 2024. The Department recommended increasing customer charges and fee revenue by $80,254, which would change revenues from $890,555 to $970,809.

2. Resolution

Parties agreed to increase test year charges and fees revenue by $70,000.

3. Decision Options

114. Require Dakota Electric to increase charges and fees revenue by $70,000. (The Department, Dakota Electric, ALJ)

115. Allow Dakota Electric to use initial amount for charges and fees revenue. (Dakota Electric Initial Filing)

G. Legacy Meters

PUC Staff: Eric Willette

1. Parties Positions

Dakota Electric, in its initial filing, included depreciation and amortization expense totaling $14,089,060 in the test year.

In Direct, the Department recommended that legacy meter not be included in DEA's test year depreciation and amortization expense because the assets have been fully depreciated. The Department recommended removal of $465,604 for DEA's test year depreciation and amortization expense.
In Dakota Electric's last rate case, Docket No. E-111/GR-19-478, the Cooperative and the OAG

agreed that there was $465,604 of annual depreciation in the test year associated with legacy meters. As of December 31, 2018, the end of the test year, the net book value of this account was $2,622,285, and Dakota Electric would continue to incur depreciation expense for meters in Acct 37000 until near the end of 2024, at which time this account would be fully depreciated.

2. Resolution

The parties agreed to reduce test year depreciation expense by $465,604 and increase accumulated depreciation by $465,604, resulting in an increase to test year revenue deficiency of $23,932, for a net reduction to the revenue deficiency of $441,672 to reflect the removal of legacy meters from the test year. This adjustment reflects the legacy meters being fully depreciated as the end of 2024.

3. Decision Options

116. Require Dakota Electric to reduce test year depreciation expense by $465,604 and increase accumulated depreciation by $465,604, resulting in an increase to test year revenue deficiency of $23,932, for a net reduction to the revenue deficiency of $441,672 to reflect the removal of legacy meters from the test year. (The Department, Dakota Electric, ALJ)

117. Allow Dakota Electric to recover depreciation and amortization expense of $14,089,060 in test year. (Dakota Electric Initial Filing)

H. Bad Debt Expense

PUC Staff: Eric Willette

1. Parties Positions

Dakota Electric, in its initial filing, included $743,567 in bad debt expense for test year 2023.

In Direct, the Department noticed bad debt expense for 2023 test year was significantly higher than other recent years. The Department recommended using a three-year average from 2022-2024, this change would smooth out yearly variation, resulting in a reduction of $189,651.

2. Resolution

The Parties agreed to reduce test year bad debt expense by $135,000.

3. Decision Options

118. Require Dakota Electric to reduce test year bad debt expense by $135,000. (The Department, Dakota Electric, ALJ)

119. Allow Dakota Electric to recover bad debt expense of $743,567 for test year as initially filed. (Dakota Electric Initial Filing)

I. MREA and NRECA Dues

PUC Staff: Eric Willette

1. Parties Positions

Dakota Electric, in its initial filing, included for recovery dues of $376,734 of which $93,747 was for National Rural Electric Cooperative Association (NRECA) membership, and $190,829 was for Minnesota Rural Electric Association (MREA) membership.

In Direct, the OAG expressed concern that customer rates are being used to pay for organizational dues that are attributable to lobbying-related activities and that the dues connection to the provision or improvement of utility services was not substantiated. The OAG explained that both MREA and NRECA advocate at the state and federal level on energy policy. The OAG recommended that in the absence of the Cooperative supporting that it has removed a reasonable amount of lobbying expenses from its dues request and supporting what portion of membership in these organizations is attributable to the provision or improvement of utility service, the entire cost of these organizational dues for MREA and NRECA should be removed from the test year.

Dakota Electric provided further support, included in Settlement Attachment 4, demonstrating the value of a portion of MREA dues to Dakota Electric's members through training and education. MREA provides its members with extensive training and education for every role at electric cooperatives including leadership, management, financial, supervisory, customer service, technical best practices, monthly onsite safety meetings, apprenticeship certification, hands-on technical skills, hotline work, and metering, among others. Education is one of the seven cooperative principles, and membership in MREA supports Dakota Electric through education and training to provide its member-owners with reliable, safe, and affordable electricity.

2. Resolution

Parties agreed to reduce test year expense by $57,249 related to a portion of MREA dues and $93,747 for the full amount of NRECA dues included in the 2023 test year.

3. Decision Options

120. Require Dakota Electric to reduce test year expense by $57,249 related to a portion of MREA dues and $93,747 the full amount of NRECA dues included in the 2023 test year. (The OAG, Dakota Electric, ALJ)

121. Allow Dakota Electric to recover dues expense of $376,734 for test year as initially filed. (Dakota Electric Initial Filing)

J. Chambers of Commerce

PUC Staff: Eric Willette

1. Parties Positions

In its Application, Dakota Electric included $13,375 related to chambers of commerce dues in the proposed test year. Dakota Electric also included $12,000 in dues for Greater MSP Partnership, a regional economic development organization working to accelerate regional competitiveness and inclusive economic growth through job creation, capital investment, and execution of strategic initiatives. In response to discovery, Dakota Electric explained that the benefits of membership in these chambers of commerce include providing a direct connection to Dakota Electric's members and an avenue to share information with business consumers on topics such as programs, rebates energy efficiency, renewable energy, and new technology; helping to disseminate information regarding issues affecting businesses; supporting workforce development and professional development efforts through training, education, recruitment, and mentorship; providing a connection to city staff and local elected officials; and supporting local economic development efforts.

In Direct, the OAG recommended limiting recovery of chambers of commerce dues and dues to Greater MSP Partnership to 50 percent of the $25,375 proposed. The OAG reasoned that chambers of commerce membership dues should be categorized as economic development expenses because the primary purpose of chambers of commerce is to increase the economies and business opportunities in the respective areas that its business members operate, and advocate for business interests. The OAG concluded that only allowing recovery of 50 percent of chambers of commerce dues is consistent with prior Commission decisions to limit recovery of economic development and chambers of commerce dues expense because such economic development activities benefit both shareholders and ratepayers.

2. Resolution

Parties agreed to reduce test year expense by $6,344, reflecting a portion of the OAG's recommended adjustment.

3. Decision Options

122. Require Dakota Electric to reduce test year expense by $6,344 related to a portion of dues for Chambers of Commerce and Greater MSP. (The OAG, Dakota Electric, ALJ)

123. Allow Dakota Electric to recover Chambers of Commerce and Greater MSP dues expense of $25,375 for test year as initially filed. (Dakota Electric Initial Filing)

K. Charitable Contributions

PUC Staff: Eric Willette

1. Parties Positions

Dakota Electric included recovery of 50 percent of actual 2023 test year charitable contributions for a total of $60,581. In support of its charitable contributions expense, Dakota Electric provided a workpaper itemizing each donation, including the organization, date of the donation, and amount. Dakota Electric stated that, consistent with Minn. Stat. § 216B.16, subd. 9, and the Commission's Policy Statement on Charitable Contributions, Dakota Electric uses its Board approved donation policy and Charitable Giving Guidelines to ensure charitable contributions benefit its members and the communities Dakota Electric serves.

In Direct, the OAG recommended requiring Dakota Electric to remove $32,687 for donations to individuals and organizations unless the Cooperative could show that it took reasonable steps to ensure that these organizations are exempt from the requirement to register with the Attorney General's Office under Chapter 309 of Minnesota Statutes, the Charitable Solicitation Act. Minn. Stat. § 216B.16, subdivision 9 allows utilities to recover up to 50 percent of qualified contributions that "the Commission deems prudent and that qualify under section 300.66, subdivision 3." The Charitable Solicitation Act requires non-exempt charities to register with the Attorney General's office, file a registration statement, pay annual fees, and provide financial information. Under Minn. Stat. § 309.515, there are certain exemptions from registration and reporting including organizations that receive less than $25,000 in contributions annually with activities performed by unpaid individuals, certain religious institutions, and certain types of educational institutions.

The OAG reasoned that donations made to organizations that the Cooperative had not determined are registered with the OAG or are exempt from registration should be removed from the test year to protect ratepayers from funding organizations that are not in compliance with Minnesota's charities' laws. The OAG also reasoned that donations made directly to individuals should be removed in full of the test year because individuals are not one of the types of entities listed in Minnesota Statutes section 300.66, subdivision 3 and these donations do not appear to comply with Dakota's Board approved donation policy and Charitable Giving Guidelines.

2. Resolution

Parties agreed to reduce test year charitable contribution expense by $32,687, the amount recommended by the OAG. The Parties further agreed that going forward, Dakota Electric will either confirm charitable contributions are registered in accordance with Minn. Stat. Ch. 309 or that the charity is exempt from registration with the Minnesota Attorney General's Office before seeking rate recovery of such contributions.

3. Decision Options

124. Require Dakota Electric to reduce test year expense by $32,687 related charitable contributions. (The OAG, Dakota Electric, ALJ)

125. Require Dakota Electric in future rate cases to confirm charitable contributions are registered in accordance with Minn. Stat. Ch. 309 or that the charity is exempt from registration with Minnesota Attorney General's Office before seeking rate recovery. (The OAG, Dakota Electric, ALJ)

126. Allow Dakota Electric to recover charitable contribution as initially filed. (Dakota Electric Initial Filing)

L. Community Events

PUC Staff: Eric Willette

1. Parties Positions

Dakota Electric provided schedules separately itemizing all travel, entertainment, and related employee expenses as required by Minn. Stat. § 216B.16, subd. 17. Workpaper 15D included itemized community events expenses of $7,729. Dakota Electric participates in community events to engage with its members and the communities it serves, allowing the Cooperative to share information with members and answer member questions.

In Direct, the OAG recommended that community events expenses be treated as charitable contributions for the purposes of ratemaking because the community events benefit many of the same organizations that also receive charitable donations. The OAG recommended removing $6,286 in community event expense from the test year because the funds went to organizations that are not registered or identified by the Cooperative as being exempt from registration with the Attorney General's Office under Chapter 309 of Minnesota Statutes, the Charitable Solicitation Act. The OAG recommended that only 50 percent of community event expense to organizations registered with the Attorney General's Office be included for recovery, consistent with the treatment of charitable contributions in Minn. Stat. § 216B.16, subd. 9. As a result, the OAG recommended removing $7,008 of community events expense from the test year.

2. Resolution

Parties agreed to reduce test year community event expense by $7,008.

3. Decision Options

127. Require Dakota Electric to reduce test year expense by $7,008 related to a portion of

community events. (The OAG, Dakota Electric, ALJ)

128. Allow Dakota Electric to recover community events expense of $7,729 for test year as initially filed. (Dakota Electric Initial Filing)

M. Cash Working Capital

PUC Staff: Eric Willette

1. Parties Positions

Cash working capital is the amount of investment in addition to net plant and materials and supplies that is necessary to provide safe and quality electric service. Dakota Electric conducted a lead/lag study to determine its test year cash working capital. A lead/lag study is an analysis that measures the length of time from providing electric service until payment is received from the customer and the length of time from the receipt of goods or services from the utility's vendors until the utility pays its vendors. Dakota Electric's applied lead/lag study factors to its test-year cash operating expenses to determine its cash working capital balance of $5,159,371 to include in rate base for the 2023 test year.

In Direct, the Department recommended adjustments to cash working capital to account for recommended adjustments to test year operating expenses. The Department noted that cash working capital should be adjusted to reflect the Commission-approved 2023 test year expense levels.

2. Resolution

Parties agreed that to incorporate the above adjustments into Dakota Electric's revenue requirement, it is necessary to update the cash working capital calculation.

3. ALJ Report

The ALJ Report recommends that the Commission approve the Settlement reached by the parties.

4. Staff Comments

The Settlement appears to be reasonable.

5. Decision Option

129. Approve the methodology used to calculate the cash working capital included in rate base. (The Department, Dakota Electric, ALJ)

130. Allow Dakota Electric to use original methodology on working capital. (Dakota Electric

Initial Filing)

N. Travel and Entertainment – Alcoholic Beverages

PUC Staff: Eric Willette

1. Parties Positions

In its Application, Dakota Electric provided schedules separately itemizing all travel, entertainment, and related employee expenses as required by Minn. Stat. § 216B.16, subd. 17.

In Direct Testimony, the OAG concluded that expenses for alcoholic beverages are not reasonable or necessary for the provision of utility service and should not be recovered from ratepayers. The OAG recommended that Dakota Electric demonstrate that it has removed all of its alcoholic-beverage expenses from the test year in future cases.

2. Resolution

Parties agreed in future rate cases; Dakota Electric will exclude all alcoholic-beverage expense from the test year.

3. Decision Options

131. Require Dakota Electric to exclude all alcoholic-beverage expense in future rate cases. (OAG, Dakota Electric, ALJ)

132. Allow Dakota Electric to recover alcoholic-beverage expense in future rate cases.

O. Base Cost of Energy

PUC Staff: Eric Willette

1. Introduction

With its Application, Dakota Electric calculated new base factors for its resource and tax adjustment (RTA) and provided the calculation of the RTA base components for cost of power, Conservation Improvement Program (CIP)/Demand Side Management (DSM) expenditures, and property taxes.

2. Resolution

Parties agreed that Dakota Electric will file a revised base cost of energy, supporting schedules, and resource and tax adjustment tariffs to be in effect with the implementation of final rates in this case.

3. Decision Options

133. Require Dakota Electric will file a revised base cost of energy, supporting schedules, and resource and tax adjustment tariffs to be in effect with the implementation of final rates in this case. (Dakota Electric, ALJ)

134. Allow Dakota Electric to not to revise base cost of energy. (Dakota Electric Initial Filing)

P. ALJ Report

The ALJ noted the following in her findings:

> 41. Fifth, other disputed financial issues are resolved in a transparent, just, and reasonable manner. These include the test year compensation expense, employee gifts and awards, benefits expense, and utility service and fee revenues. The Settlement adopts multiple financial adjustments based on testimony filed by the Department and the OAG. As part of settlement discussions, Dakota Electric provided additional support for its test year compensation expense and Minnesota Rural Electric Association (MREA) dues, and that additional information was included in attachments to the Settlement Agreement.
>
> 45. Ninth, as part of the Settlement, the Cooperative agreed that going forward, it would either confirm charitable contributions are made to entities that are registered in accordance with Minn. Stat. Ch. 309 or that the charity is exempt from registration with the Minnesota Attorney General's Office before seeking rate recovery of such contributions.
>
> 46. Tenth, Dakota Electric agreed that in future rate cases it will exclude alcoholic beverage expenses from test year recovery.

Q. Staff Comment

Staff has reviewed the financial issues in the settlement and finds the agreement to reasonable.

VI. CLASS COST OF SERVICE STUDY

PUC Staff: Andrew Larson

A. Introduction

Dakota Electric filed its proposed Class Cost of Service Study to provide information to be used in designing rates. The purpose of a Class Cost of Service Study (CCOSS) is to allocate costs, which have been previously categorized based on the Uniform System of Accounts, to the various functions of a utility (e.g. Generation, Transmission, Distribution, General/Customer Service) and to the rate classes, based on which class or classes, and function or functions,

'caused' the costs in each account to be incurred.[17] The CCOSS is then used in the rate design process to aid in determining the appropriate billing determinant to use to recover the costs delegated to each customer class. Dakota Electric provided a detailed Guide to its CCOSS as Attachment 22 to its rate case, which provides detail on how it functionalized and allocated the costs for each account in the Uniform System of Accounts. Dakota Electric used what is known as a "fully allocated average embedded cost of service" approach, which is typical for this jurisdiction. This means that costs are allocated on an average system-wide basis (rather than calculating the marginal cost of service) and the 'embedded' (accounting) costs, as recorded on Dakota Electric's books are used for the model.

The first step of a CCOSS is functionalization, which assigns all costs to a specific utility function, such as generation, transmission, etc. The Federal Energy Regulatory Commission (FERC) has created a Uniform System of Accounts (or FERC Accounts) which most utilities use in their accounting systems to record and classify costs. Dakota Electric functionalized its costs to Purchased Power, Transmission, and Distribution functions**.**

Once the costs are functionalized, the costs in each account are classified as customer, demand, or energy costs. This classification is used to generally inform whether the cost is recovered through a customer charge, an energy (per kWh) charge, or a demand (per peak demand kw usage) charge.

Customer costs are those that scale with the number of customers. Typical customer related costs include billing costs, 'minimum system' costs which consist of the minimum amount of equipment (for example, meters, which every non-lighting customer has at point of delivery) required to hook up a customer to the grid, and customer service.

Energy costs are those that scale with electricity total usage, for example, purchased energy or fuel for generation. Demand costs are those that scale with maximum usage, such as purchased demand, transmission capacity, distribution capacity.

Finally, the costs are allocated to customer class. Each FERC Account is allocated across the various customer class by an allocation factor. Typically, as many costs as possible are allocated 'directly', meaning they are assigned to the customer classes they serve. For example, costs related to a substation which only serves large industrial customers might be directly allocated to the large industrial class. Once costs which can be directly allocated are, those that are left are allocated based on allocation factors which are determined based on how those costs were classified and functionalized. For example, transmission assets are usually classified as demand related and would be allocated in proportion to each customer class's power usage at the peak demand time(s) for the utility.

Dakota Electric used the same model that was approved in its last rate case, with one modification. In Docket E-111/GR-14-482, the Commission required that Dakota Electric include

[17] A guide to Dakota Electric Association's Class Cost of Service Study was provided as Ex. DEA-6 (Workpaper 22).

a demand adjustment to its minimum system allocator in its CCOSS submitted in its next (i.e. this) rate case.[18] A minimum system allocator attempts to identify the lowest cost system which would be installed if demand (load) were not an issue. For example, Account 364 consists of Poles, Towers, and Fixtures, and is the accumulated cost of all utility poles and towers installed on the system. The minimum system allocator calculates how much the system would have cost to build if the lowest cost poles (for example) in widespread use had been used to construct the entire system. This minimum cost is then attributed to customers, and costs are allocated to the "customer service" function which is usually allocated on a per customer basis to class and would be theoretically billed via the customer charge.

In this case, Dakota Electric developed four scenarios to evaluate minimum system:

1. 1 kW Feeder with load growth percentages applied
2. 100 kW and 500 kW per feeder options
3. 200 kW per feeder
4. 200 kW per feeder and then increasing load on individual substations.

Dakota Electric found that each of the first three scenarios caused significant reliability errors and so adopted scenario 4. The results of this classification are below:

Table 2: Consumer Component of Distribution System Accounts by Method[19]

Account	Minimum System	Demand Adjusted
364 – Poles, Towers and Fixtures 44% 44%	41.72%	41.72%
365 – Overhead Conductors and Devices 28.76% 16.52%	26.19%	10.42%
367 – Underground Conductors and Devices 78.63% 74.96%	78.34%	73.72%
Account 368 – Line Transformers 30.6% 18.67%	33.09%	18.80%

The demand adjustment notes that this minimum system size still can serve a minimum load greater than zero, and so some of the cost allocated to the consumer component is still demand-related. The adjustment then removes from the consumer component the average installed cost per system peak load demand unit (kilowatts) times this minimum load and reassigns it to demand. The effect is to allocate less of these accounts on a customer basis, and more on a demand or energy basis.

This adjustment to the minimum system allocator makes it more similar to a 'zero intercept' allocator, which uses linear regression to predict the cost of the poles (in this example) using their

[18] In the matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E-111/GR-14-482, Findings of Fact, Conclusions, and Order at 27 (June 8, 2015).
[19] DEA Ex.-6 (Workpaper 21).

capacity-related attributes as independent variables, and attributes to customer counts the constant term in the regression (which is the zero intercept, the cost of a theoretical pole where capacity is equal to zero). For comparison and further information, DEA also provided a summary comparison to a zero-intercept model in its workpapers.[20]

The results of the Class Cost of Service Study are summarized below:

Table 3: Results of Class Cost of Service Study by Category[21]

Rate Class	Cost Category			
	Power Supply ($)	**Transmission ($)**	**Distribution ($)**	**Total ($)**
Residential & Farm (31, 32, 53)	71,383,745	23,537,135	49,161,928	144,082,807
Small General Service (41)	3,047,842	815,785	3,348,888	7,212,515
Irrigation (36)	569,565	40,308	428,220	1,038,093
General Service (46, 54)	37,157,836	9,850,725	9,378,955	56,387,516
Interruptible Service (70, 71)	20,164,715	194,518	4,449,121	24,808,354
Street and Security Lighting	698,856	180,867	2,094,821	2,974,544
Total	133,022,559	22,649,623	56,774,205	236,503,829

[20] Id.

[21] Ex. DEA-3 at 40 (Heinen Direct)

Table 4: Cost of Service Summary[22]

Rate Class	Revenue Present Rates[23]	Revenue Requirement	Amount	Percent[24]
Residential & Farm (31, 32, 53)	125,506,455	144,082,807	18,576,352	14.82
Small General Service (41)	6,075,155	7,212,515	1,137,360	18.75
Irrigation (36)	979,288	1,038,093	58,805	6.01
General Service (46, 54)	54,041,357	56,387,516	2,346,159	4.35
Interruptible Service (70, 71)	23,637,208	24,808,354	1,171,145	4.96
Street and Security Lighting	2,445,447	2,974,544	529,096	21.66
Total			Total System	11.00

B. Parties' Positions

The Department generally agreed with the methodologies used by Dakota Electric in its CCOSS, and specifically agreed that the Demand Adjusted Minimum System study conformed to the Commission's repeatedly expressed preference for the usefulness of multiple CCOSS results and a range of CCOSS results.[25] The Department also made the following recommendations:[26] 1) Dakota Electric use a cost escalator in future rate cases to adjust historical book costs to the real cost of replacement,[27]2) Dakota Electric update its adjustments for classes not in the CCOSS and discuss why it was reasonable to split these costs almost evenly across categories, 3) DEA discuss whether it has data related to the year and cost for specific installations of equipment, and 4) the Commission use the CCOSS range suggested by the Department. The Department found that the Dakota Electric CCOSS was generally reasonable and recommended adoption of the Company's CCOSS.

22 Ex. DEA-3 at 39 (Heinen Direct)

23 Includes an allocated share of Other Operating Revenue.

24 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

25 Ex. DOC-8 at 36 (Zajicek Direct)

26 Id. At 34-39.

27 Id. At 34

Table 5: Department CCOSS Range[28]

Rate Class	Operating Revenues at Current Rates	Basic Customer CCOSS Rates	Basic Customer Percent Increase	Minimum System CCOSS Rates	Minimum System CCOXX Percent Increase
Residential & Farm	$125,506,455	$136,963,508	9.13%	$142,593,278	13.61%
Small General Service	$6,075,155	$6,620,316	8.97%	$7,057,255	16.17%
Irrigation	$979,288	$1,091,818	11.49%	$1,065,302	8.78%
General Service	$54,041,357	$60,381,192	11.73%	$57,010,407	5.49%
C&I Interruptible	$23,637,208	$27,922,723	18.13%	$25,311,328	7.08%
Lighting	$2,445,447	$3,021,063	21.54%	$2,963,050	21.17%
Total	$212,684,912	$236,000,620	10.96%	$236,000,620	10.96%

Table 6: Department Recommended CCOSS Range Apportionment Percentage[29]

Customer Class	Basic Customer CCOSS Apportionment Percent	Minimum System CCOSS Apportionment Percent
Residential & Farm	58.04%	60.42%
Small General Service	2.81%	2.99%
Irrigation	0.46%	0.45%
General Service	25.59%	24.16%
C&I Interruptible	11.83%	10.73%
Lighting	1.28%	1.26%
Total	100.00%	100.00%

The OAG believed that the Basic Customer and Peak & Average method CCOSSs were more reasonable than Dakota's minimum system study and recommended the Commission give them more weight in determining revenue apportionment [30] The OAG also proposed several modifications to the classification and allocation of costs that were incorporated into these CCOSSs.

C. Settlement

The Parties agreed that the Commission does not need to make any specific finding regarding

[28] *Id.* at 38

[29] *Id.*

[30] Ex. OAG-2 at 57-62 (Stevenson Direct).

the CCOSS recommendations made by Dakota Electric, the Department, or the OAG given the Parties' agreements on revenue apportionment and fixed monthly charges. Furthermore, the Parties agreed that in the future, Dakota Electric will include all customer classes in its CCOSS or provide a detailed explanation for why inclusion of certain classes was not feasible or reasonable. If any classes are excluded from Dakota Electric's future CCOSS, the Cooperative will ensure the overall proposed revenue deficiency reconciles for all classes.

D. ALJ Report

The ALJ noted the following in her findings:

> 22. The Cooperative also provided a Class Cost of Service Study (CCOSS) aimed at identifying the cost responsibility of each rate class, using a fully allocated average embedded approach. Dakota Electric developed the CCOSS based on a minimum system study to classify specified distribution accounts, incorporating a demand adjustment.
>
> 39. Third, the Settlement is informed by, but does not endorse, any single CCOSS. In some recent general rate case proceedings, the Commission has preferred to consider multiple CCOSSs rather than to base cost classification and allocation upon a single CCOSS.

E. Staff Comments

Staff reviewed the record and concurs that the agreed upon CCOSS is reasonable.

F. Decision Options

201. Approve Dakota Electric's corrected CCOSS as reasonable as recommended by the ALJ. (ALJ, Dakota Electric, Department, OAG)

VII. COST OF CAPITAL

PUC Staff: Godwin Ubani

A. Introduction

The rate of return (ROR) is intended to ensure that earnings are sufficient to cover the cost of debt (interest) and generate a fair return on the investment (equity) for the member-owners of Dakota Electric. DEA, like any other business operation needs capital to meet current operating expenses and provide for future business expansion. Capital consists of debt and equity. Debt capital is money borrowed by the Company on a short- or long-term basis that must be repaid back on time to the owners of the money.

For Dakota Electric equity capital is provided by the owner-members, who are also its customers. By way of contrast, an investor-owned utility (IOU) must induce investors to take the risk of

investing in the utility by offering an attractive return on equity. An IOU must pay a return equal to the return that investors expect to earn on investments of comparable risk elsewhere. When investors buy the common stock of an IOU, they acquire the right to share in any dividends that the utility may declare in the future. The prospect of earning the dividends serves as an inducement to investors and is a critical component of the cost of common equity capital.

Unlike the case of an IOU, Dakota Electric is a cooperative with the ratepayers servings as its investors, and as such the required rate of return on the cooperative's equity is not determined by the opportunity cost of investing capital somewhere else; but instead, determined by the need to finance the growth of the Company's rate base and maintain a sound capital structure.

The equity portion of the capitalization of Dakota Electric is collected from the utility's customers through the rates. When revenues exceed expenses, each owner-member of the cooperative is assigned a portion of the margin (that is, the portion of the amount by which revenues exceed expenses) based on a customer's electricity consumption as a fraction of the total electricity consumed by all customers over the year. This margin is accumulated over the period of a year – called capital credits, also known as patronage capital for each customer.

Dakota Electric does not pay dividend in the tradition sense, but the accumulated capital credits are retired (or returned) to the customers/members when the cooperative is financially strong, and the cumulative capital credit level is high.

The Commission has noted that ROR as applied to cooperatives, allows for the development of sufficient margins to cover the cost of debt and equity capital.[31] Dakota Electric notes that the ROR method is intended to ensure that the Company's earnings are sufficient to cover the cost of debt (interest) and generate a fair return on the investment (equity) for the owners.[32] Because Dakota Electric is a cooperative, the "return on equity" is related to the retirement, or rotation, of patronage capital.

For a typical electric utility, the weighted cost of capital is applied to the rate base to obtain the required rate of return. As the Department pointed out, for a typical electric utility, the test year rate base is equal to or only slightly different from total capitalization and, therefore, for a typical utility, the weighted cost of capital can be applied to the rate base directly.[33]

However, in Dakota Electric's case, there is a divergence between the test-year capitalization and rate base. As the Department noted, this is sometimes due to regulatory treatment of various assets that may or may not be included in the rate base.[34] Besides, unlike an IOU, the Cooperative is required to pay patronage capital to its members, making such payments to

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[31] Findings of Fact, Conclusions of Law and Order in DEA's rate case (Docket No. E-111/GR-09-175), May 24, 2010, at 10.

[32] DEA Ex. 6 at 19 (Heinen Direct).

[33] DOC Ex. 8 at 27-28 (Kundert Direct).

[34] Id.

equity holders similar to the interest payments made to bond holders. Also, the Department noted, because Dakota Electric purchases equity capital only from its members, who are required to invest in the Company in order to receive electric service, and because Dakota Electric does not pay dividends out of its earnings, the Company's required rate of return on equity would be lower than its true cost of equity capital.[35]

The Department stated that because the overall ROR is applied to the rate base to produce the appropriate level of net income, the overall ROR on total capital must be adjusted to allow Dakota Electric to earn the same amount on its rate base as it would earn on its total capitalization. Additionally, to allow both bondholders and equity holders (Dakota Electric's members) to recover their investment costs, the return on total capital must be adjusted to recognize any difference between the rate base and total capitalization.[36]

This adjustment to Dakota Electric's weighted (or overall) cost of capital requires that the ROR be calculated as follows:

ROR = Weighted Cost of Capital * Rate Base Factor

The Rate Base Factor is defined as: Total Capitalization/Approved Rate Base.

If the Commission-approved rate base changes, the return on rate base will also change.

B. Parties' Positions

Dakota Electric Association proposed the following test-year capital structure and return on type of capital in this rate case:[37]

Table 7: Dakota Electric's Proposed Rate of Return[38]

Type of Capital	Proportion to Total Capital	Cost Rate	Weighted Cost
Long-Term Debt	49.735%	3.47%	1.73%
Common Equity	50.265%	3.94%	1.98%
Weighted Cost of Capital	100%		3.71%
Return on Rate Base		Rate Base Factor = 1.444	5.30%

In Direct Testimony, the Department recommended the following capital structure and rate of

[35] Id.

[36] Id., at 27.

[37] DEA Ex. 2 at 18-24 (Heinen Direct).

[38] DEA Ex. 15 at 9,12 and 28 (Kundert Direct)

return:[39]

Table 8: Department's Proposed Rate of Return[40]

Type of Capital	Proportion to Total Capital	Cost Rate	Weighted Cost
Long-Term Debt	41.390%	3.47%	1.44%
Common Equity	58.610%	3.69%	2.161.87%
Weighted Cost of Capital	100%		3.60%
Return on Rate Base		Rate Base Factor = 1.428	5.14%

The parties agreed on the rate of return that was recommended by the Department.

C. ALJ Report

The ALJ noted the following in her findings:

> 40. Fourth, the Settlement's proposed return on equity, overall cost of capital, and overall return on rate base are 3.69%, 3.60%, and 5.14%. These rates adopt the Department's recommended adjustments to Dakota Electric's initial proposal and are based on the actual 2023 historical capital structure, which are reasonable and supported by the record.
>
> 51. The Settlement adopts Dakota Electric's 2023 historical capital structure to calculate the Cooperative's required return on equity, overall cost of capital, and overall return on rate base. The actual 2023 equity ratio is 58.61%, and the actual debt ratio is 41.39%, resulting in test year return on equity, overall cost of capital, and overall return on rate base of 3.69%, 3.60%, and 5.14%.

D. PUC Staff Comment

Staff reviewed the record and concurs that the agreed upon rate of return is reasonable and is consistent with how Dakota Electric's rate of return has been calculated and determined in previous DEA rate cases.

E. Decision Options

301. Adopt the settlement rate of return.

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[39] DOC Ex. 2 at 5-8 (Kundert Direct).

[40] DOC Ex. 2, Schedule MBK-D-6, page 1 (Kundert Attachments).

VIII. SALES FORECAST

PUC Staff: Andrew Larson

A. Introduction

Dakota Electric Association's sales forecast is composed of customer count, energy sales, and billing demand times appropriate service schedule rates to determine class and system revenue**.**

Dakota Electric serves approximately 115,000 electric members in Dakota, Scott, Rice and Goodhue Counties, and has experienced an overall downward trend in average kWh per member per month over the last ten years. The Cooperative's highest level of total kWh sales was achieved in 2007 with 1,897,654,115 kWh sold and 99,959 members/meters at the end of the year.[41] After normalizing for weather, average residential monthly kWh usage decreased on average about 0.8 percent per year from 2014 to 2023. Average monthly kWh usage for the general service class (Rate 46) was roughly unchanged from 2014 to 2023.

B. Parties' Positions

In its Petition, Dakota Electric estimated a test-year sales forecast of 1,872,343,646 kWhs and corresponding revenue of $216,408,767. A detailed break-down of Dakota Electric's test-year customer count and sales forecast are given further below in Table 7.

In Direct Testimony, the Department noted that sales levels are an integral input in calculating Dakota Electric's rates and, therefore, the method of determining the sales levels must be reasonable.[42] After a thorough review, the Department concluded that Dakota Electric's data preparation for forecasting energy sales was reasonable.

The Department supported Dakota Electric's test-year sales estimate of all classes of customers, except the Residential & Farm Service (Rate Category 31) which accounts for nearly 46 percent of the Company's total test-year sales.

The Department's main concern was that, for Residential & Farm Service, Dakota Electric predicated the kWh use per customer on, among other variables, the number of customers themselves, in what appeared to be circular reasoning.

The Department re-estimated the kWh usage per customer for this class after excluding the number of customers as an explanatory variable. The Department's re-estimation resulted in use per customer of 692.48 kWh per month, as opposed to Dakota Electric's estimate of 691.11 kWh/month/customer[43]-- admittedly a very negligible difference.

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[41] Ex. DEA-6, Initial Filing, Vol. 2, Workpaper 13, page 1, Sales History and Forecasted Test Year Normalization.

[42] Department Ex-5 at 12-13. (Zhang Direct)

[43] Id. at 12-13

However, applying the Department's calculations over the total number of Residential & Farm Service customers of 116,945, and over the 12 months of the test-year, yielded a test-year sales figure of 895,719,589 kWh.[44] The corresponding total test-year revenue figure for the Residential & Farm Service worked out to $126,902,867.

In sum, the Department's upward adjustment to Dakota Electric's test-year sales volume results in an increase in total test-year revenue of $221,558 (0.17 percent) and a corresponding increase in power costs of $158,790, reducing the revenue deficiency by $62,768.[45]

C. Settlement

The Parties agreed to reduce the test year revenue deficiency by $62,768, consistent with the Department's recommended adjustments to the test year sales forecast. This adjustment increases residential class revenue by $221,558. In addition, this adjustment increases test-year cost of purchased power by $158,790, yielding a net reduction to the revenue deficiency of $62,768.[46]

D. Staff Comments

Staff reviewed the record and concurs that the agreed upon sales forecast is reasonable.

E. Decision Options

401. Approve Dakota Electric's proposed test-year customer count and energy sales volumes for all classes of customers with the exception of the Residential and Farm Service class. For the Residential and Farm Service class, approve the adjustments recommended by the Department and accepted by Dakota Electric. (ALJ, Dakota Electric, Department)

IX. RATE DESIGN

PUC Staff: Andrew Larson

A. Introduction

Rate Design is the second step of a two-step ratemaking process. The purpose of rate design is to assign revenue responsibilities to customer classes. Once the appropriate revenue level, or revenue requirement is determined, the Commission must determine the rates used for charging the utility's customers for service. In setting rates, the Commission should be aware that rates must be just and reasonable[47] and an important aspect of reasonable rates is their design. It should be noted also that rate design is largely a quasi-legislative function, involving

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[44] 692.475314 kWh * 116,945 * 12 = 895,719,589 kWh

[45] Id.

[46] Settlement at 8-9

[47] Minn. Stat. §§ 216B.03, 216B.07

policy decisions. A key purpose of rate design is determination of which customer classes should be apportioned responsibility for paying the costs that are reflected in the revenue requirement and what kinds of rates should be used to recover those costs.

B. Apportionment of Class Revenue Responsibility

1. Introduction

Dakota Electric offers service to approximately 117,000 customers (members) of which approximately 99 percent fall into the Residential & Farm, Small General and General Service Rate Classes. Table 9 below shows Dakota Electric's apportionment of tariff revenues among rate classes, customer counts, and sales figures for each customer class.

Table 9: 2024 Forecasted Customer Class and Sales[48]

Rate Class	Forecasted Customers	% of Total Customers	Energy Sales (kWh)	% of Sales
Resd. & Farm Srv. (31, 32, 53)	107,825	92.20	894,555,203	47.78
Small General Service (41)	4,829	413	42,012,300	2.24
Irrigation Service (36)	394	0.34	9,552,000	0.51
General Service (46, 54)	2,842	2.43	501,517,782	26.79
Interruptible Service (70 & 71)	263	0.22	349,844,681	18.68
Street and Security Lighting (44)	-	N/A	10,903,068	0.58
Electric Vehicle (33)	791	0.68	3,652,012	0.20
Low Watt. Unmetered Srv. (45)	-	N/A	-	N/A
Municipal Civil Def. Sirens (47)	-	N/A	-	N/A
Geothermal Heat Pump (49)	3	0.003	198,000	0.01
Controlled Energy Storage (51)	-	N/A	14,151,000	0.76
Contr. Interruptible Service (52)	-	N/A	45,957,600	2.45
Standby Service (60)	1	0.001	-	N/A
Wellspring	-	N/A	-	N/A
Cycled Air Cond. Service (80)	-	N/A	-	N/A
Total	**116,948**	**100%**	**1,872,343,646**	**100%**

Dakota Electric stated that its initial proposed revenue apportionment was based on the results of its CCOSS, along with other rate design objectives, including the need to avoid abrupt changes and its desire to achieve member acceptance. The result is a revenue increase being attributed to each class and ranging from a low of 5.87 percent for the Irrigation Service (36) Interruptible class to a high of 100.0 percent for the Municipal Civil Defense Sirens (47) class. Within that range of increases, the Cooperative proposed a 13.05 percent increase for the Residential and Farm Service (31) class and a 7.01 percent increase for the General Service class.[49] Table 10 presents Dakota Electric's apportionment of its current and initially proposed

[48] Ex. DEA-1, Exhibit 1 at 12 (Heinen Direct)

[49] Ex. DEA-3 at 50-52 (Heinen Direct)

revenue requirements.

Table 10: Comparison of Revenue – Present and Proposed Rates[50]

Rate Class	Revenue Present Rates	Revenue Proposed Rates	Increase (Decrease) Amount	Percent
Residential & Farm Service (31)	$126,681,309	$143,214,865	$16,533,556	13.05%
Residential & Farm Demand Control (32)	45,111	52,057	6,946	15.40
Electric Vehicle (33)	315,139	337,392	22,253	7.06
Irrigation Service (36) Firm	47,127	49,917	2,790	5.92
Irrigation Service (36) Interruptible	930,863	985,474	54,611	5.87
Small General Service (41)	6,167,331	7,002,386	835,055	13.54
Security Lighting Service (44)	85,004	98,058	13,054	15.36
Street Lighting Service (44-2)	444,233	513,956	69,723	15.70
Street Lighting System (44-1)	71,540	83,018	11,478	16.04
Custom Residential Street Lighting (44-3)	1,531,694	1,770,887	239,193	15.62
LED Security Lighting Service (44-4)	49,465	56,881	7,416	14.99
LED Street Lghtg Member-Owned (44-5)	1,453	1,684	231	15.9
LED Street Lighting (44-6)	258,816	298,186	39,370	15.21
Low Wattage Unmetered Service (45)	8,442	14,070	5,628	66.67
General Service (46)	53,817,780	57,588,174	3,770,394	7.01
Municipal Civil Defense Sirens (47)	3,960	7,920	3,960	100.00
Geothermal Heat Pump (49)	21,226	24,691	3,465	16.32
Controlled Energy Storage (51)	747,172	857,551	110,379	14.77
Controlled Interruptible Service (52)	2,752,860	3,097,543	344,683	12.52
Residential & Farm Time of Day (53)	46,584	50,561	3,977	8.54
General Service Time of Day (54)	151,922	164,380	12,458	8.20
Standby Service (60)	74,160	79,680	5,520	7.44
Full Interruptible Service (70)	21,395,714	22,921,191	1,525,477	7.13
Partial Interruptible Service (71)	2,210,153	2,360,551	150,398	7.13
Cycled Air Conditioning Service (80)	(1,533,193)	(1,533,193)	0	0

2. Parties' Positions

Dakota Electric proposed rates for twenty-five main rate classes, each class comprising several rates.

The Department observed that Dakota Electric's Minimum System cost increases resulted in wide variations in percentage cost increases across classes[51]Therefore, it recommended the Commission approve an equal 10.79 percent increase of revenue apportionment among

[50] Id. at 13 (Heinen Direct)

[51] Ex. DOC-9 at 22-23 (Bahn Direct)

customer classes and require Dakota Electric to adjust the rates under each customer class accordingly.[52] The Department also recommended the Commission require the Cooperative to adjust its proposed rates so that total revenues equal total revenue requirement. Furthermore, the Department requested Dakota Electric to explain why it excluded the nine services not included in its CCOSS.

The OAG believed that once the overall revenue requirement is set, a higher fixed charge would allow Dakota Electric to lower its distribution charge. This change in the marginal cost of electric consumption would incentivize members to increase their electricity consumption. Ultimately, in response, Dakota Electric would need to increase its electricity purchases, and in the long-run, members would pay for the higher energy purchases. Therefore, in partial recognition of the Cooperative's argument, the OAG recommended a customer charge of $12 for schedule 31 residential customers, $15 for schedule 32 residential customers, and $15 for schedule 53 residential customers.[53]

Also, the OAG recommended a $467,085 reduction of the revenue requirement for Dakota Electric's EV classes for two reasons.[54] First, the OAG argued that the Cooperative's cost allocation between capacity, demand and customer-related factors is incorrect. Dakota Electric allocated 50 percent to capacity and demand factors, with zero allocated to customer-related costs. Second, the OAG had concerns that when Dakota Electric revised its EV tariff schedules, did not property weight its residential EV rate to peak energy consumption.

The effect of the OAG's recommended changes would be to increase the revenue recovery in Dakota Electric's load management classes, which are not listed in the CCOSS, by $467,085. Accordingly, the revenue recovery from the classes listed in the CCOSS would decrease by the same amount.

3. Settlement

The Settlement modifies the rate design proposed by the Cooperative by reducing the Residential and Small General Service class revenue increases and adopting a more moderate increase to the Residential and Farm Service fixed monthly customer charges, as set forth in Table 11.[55]

[52] Ex. DOC-9 at 47-48 (Bahn Direct)

[53] Ex. OAG-2 at 108-110 (Stevenson Direct)

[54] Id.at 101-107.

[55] Settlement at 17-18, and Attachment 2, page 1 of 7

Table 11: Dakota Electric Association Settlement Revenue Apportionment				
	Present Revenues	Final Revenue Increase	Percent Rate Increase	Revenue Apportion-ment
Residential & Farm Service (31)	$126,681,309	$137,227,050	8.32%	57.85%
Residential & Farm Demand Control (32)	45,111	49,544	9.83	0.02
Electric Vehicle (33)	315,139	336,801	6.87	0.14
Irrigation Service (36) Firm	47,127	50,477	7.11	0.02
Irrigation Service (36) Interruptible	930,863	1,000,302	7.46	0.42
Small General Service (41)	6,167,331	6,678,892	8.29	2.82
Security Lighting Service (44) Closed to New	85,004	97,414	14.60	0.04
Street Lighting Service (44-2)	444,233	510,481	14.91	0.22
Street Lighting System (44-1)	71,540	82,473	15.28	0.03
Custom Residential Street Lighting (44-3)	1,531,694	1,758,829	14.83	0.74
LED Security Lighting Service (44-4)	49,465	56,496	14.21	0.02
LED Street Lighting Member Owned (44-5)	1,453	1,672	15.07	0.00
LED Street Lighting (44-6)	258,816	296,194	14.44	0.12
Low Wattage Unmetered Service (45)	8,442	14,070	66.67	0.01
General Service (46)	53,817,780	60,006,311	11.50	25.30
Municipal Civil Defense Sirens (47)	3,960	7,920	100.00	0.00
Geothermal Heat Pump (49) Closed to New	21,226	24,691	16.32	0.01
Controlled Energy Storage (51)	747,172	857,551	14.77	0.36
Controlled Interruptible Service (52)	2,752,860	3,097,543	12.52	1.31
Residential & Farm Time of Day (53)	46,584	49,125	5.45	0.02
General Service Time of Day (54)	151,922	170,992	5.45	0.02
Standby Service (60)	74,160	79,680	7.44	0.03
Full Interruptible Service (70)	21,395,714	23,755,914	11.03	10.01
Partial Interruptible Service (71)	$2,210,153	$2,486,319	12.50	1.05%
Cycled Air Conditioning Service (80)	$(1,533,193)	$(1,533,193)	0.00%	-0.65%
	$216,325,865	$237,163,548.97		99.981833%
Revenue Apportionment after Rate Design		$20,837,683.97		
Agreed Revenue Deficiency		$20,880,700		
Amount below agreed Revenue Deficiency		$43,016.03		

4. Decision Options

501. Approve the revenue allocation as recommended by the ALJ. (ALJ, DEA, Department, OAG)

C. Fixed Monthly Customer Charge

1. Introduction

Dakota Electric proposed changes to several monthly fixed charges based on its costs.[56]

Dakota Electric uses this cost based fixed charges, and the seven rate design principles, to guide a detailed analysis into what are appropriate fixed charges.[57] There are many legitimate objectives that influence the design of rates. Monthly fixed customer charges are an important component of the Cooperative's rates that facilitate recovery of the costs caused by each member that do not vary with the amount of energy used. When considering its recommended monthly fixed charges, Dakota Electric used the following factors:

> 1. The proposed rates must develop the requisite total revenue and be designed to allow the utility a reasonable opportunity to recover its revenue requirement.
>
> 2. The proposed rates should reflect the cost of providing service. No class or subclass should subsidize or be subsidized by another.
>
> 3. The rate schedules should be simple and concise to facilitate consumer acceptance and administration.
>
> 4. Abrupt departures from historical rate practices and levels should be avoided.
>
> 5. The rate structure should be acceptable to the membership.
>
> 6. Where there is a possibility of a consumer being eligible to receive service under more than one rate schedule, the transition should be made as smoothly as possible.

Notably, Dakota Electric proposed to raise the monthly fixed charge for Residential & Farm Service by $3.00, to $13.45.

The Department believed the Commission should also consider other factors when moving the customer fixed charge to cost, such as continuity with prior rates to avoid rate shock, customer ability to pay, and incentive to energy conservation.[58]

Therefore, the Department disagreed with the Cooperative on its recommended increases in the customer charge for Residential and Farm (31, 32, 53 and 56), and Interruptible Services (70 and 71). The recommended residential increase is too great of a rate shock with an increase of 30.45 percent. The Department recommended a 20 percent increase.

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[56] DEA Ex-3 at 51-80 (Heinen Direct)

[57] DEA Ex-6 (Workpaper 26)

[58] Department Ex-9 at 28-29 (Bahn Direct)

The Department did not recommend an increase for the Residential and Farm Demand Control (32) or Residential and Farm Time of Day (53, 56), because these customer classes have similar, or the same, customer-related costs as the Residential and Farm Service (31) and the current customer charge is already set $1.00 more per month than the Department's recommendation for the Residential and Farm Service (31). Likewise, the Department recommended no increase for Irrigation (36) since its customer charge is already greater than customer-related costs without the inclusion of transformer-related costs. Similarly, the Department recommends no increase for Interruptible (70 and 71) classes.

The OAG recommended the Commission approve a customer charge of $12 for Schedule 31 residential customers, $15 for Schedule 32 residential customers, and $15 for Schedule 53 residential customers. The OAG agreed with Dakota Electric and the Department to approve the proposed fixed charge for small general service customers.[59]

2. Settlement

For purposes of this Settlement, the Parties agree that fixed monthly customer charges should be approved consistent with the Department's recommendation as follows:[60]

Table 12: Fixed Monthly Customer Charges Agreed to in the Settlement

Customer Class	Current Fixed Monthly Customer Charge	Proposed Fixed Monthly Customer Charge
Residential &Farm Services (31)	$10.00	$12.00
Residential& Farm Demand Control (32)	$13.00	$13.00
Residential & Farm Time of Day (53, 56)	$13.00	$13.00
Small General Service (41)	$15.00	$17.50
Irrigation (36)	$33.00	$33.00
General Service (46)	$37.00	$48.00
General Service Time of Day (54)	$39.00	$48.00
Interruptible (70 & 71)	$130.00	$130.00
Low Wattage Unmetered Service (45)	$10.50	$17.50
Municipal Civil Defense Siren (47)	$5.00	$1.000

[59] OAG Ex-2 at 109 (Stevenson Direct)

[60] Settlement at 17

3. Decision Options

502. Approve the customer charges as recommended by the ALJ. (ALJ, DEA, Department, OAG)

D. Residential Time of Day Rates (53)

1. Introduction

Dakota Electric proposed changes in the hourly zones for Residential Time of Day Rates. Since no customers are taking this rate, there is no revenue impact. The Cooperative proposed no rate changes, and the Department opposed any change because this class is similar to the Residential class, but its fixed monthly customer charge is already $1 higher than the Department's recommended Residential class rate.[61]

2. Decision Options

503. Approve the Residential Time of Day Tariff as recommended by the ALJ. (ALJ, DEA, DOC)

E. Standby Service Rate

1. Introduction

Dakota Electric proposed, in keeping with a Commission-approved methodology, to increase primary and secondary distribution reservation fees (respectively, from $3.89/kW to $4.35/kW, and from $4.02/kW to $4.49/kW), and to increase its substation distribution reservation fee ($0.81/kW to $0.91/kW).[62] The Department recommended approval[63]

2. Decision Options

504. Approve the Standby rates as recommended by the ALJ. (ALJ, DEA, Department)

F. Electric Vehicles Charges

1. Introduction

Dakota Electric proposed an increase in Standby Service fees.

Dakota Electric proposes a modification to the off-peak charging period and an update to the rates for the service based on its Test Year wholesale power and distribution analysis. In recent years, Dakota Electric has observed later evening wholesale power peaks and morning peaks.

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[61] Department Ex-9 at 29 (Bahn Direct)

[62] DEA Ex-3 at 77 (Heinen Direct)

[63] Ex DOC-9 at 37-38 (Bahn Direct)

These events increase the risk that electric vehicle charging will inadvertently happen over peak hours and raise costs for all members.[64]

Dakota Electric proposes to increase its On-Peak and Off-Peak rates. On-Peak rates would increase from $0.4420 to $0.4200 per kWh. Off-Peak rates would increase from $0.0755 to $0.0803 per kWh.

The Department supports Dakota Electric's proposal to adjust charging periods and to increase its On-Peak and Off-Peak rates to reflect higher costs from the Company's wholesale provider, Great River Energy.[65]

The OAG also supported the Cooperative's proposals.[66]

In the Settlement, Parties agreed that Dakota Electric will file a plan to educate members on the new peak EV charging hours. Adding a second peak to the charging hours could be confusing to EV customers who are accustomed to the prior tariff.[67]

2. Decision Options

505. Approve the Electric Vehicle rates as recommended by the ALJ. (ALJ, DEA, Department, OAG)

506. Approve the plan educating Electric Vehicle customers on the new peak charging hours. (ALJ, DEA, Department, OAG)

G. Line Extension Charges

1. Introduction

Dakota proposed to modify its line extension charges. Dakota proposed to change its base fee to $1,350.00 plus $15.00 per foot for each foot of the extension (with no free footage allowance). Dakota Electric also proposes to update the line extension factors applicable for extensions to members receiving service under Schedule 41, Schedule 46, and Schedules 70/71.14.[68]

The Department recommends approval of Dakota Electric's proposed increase of the flat fee and the per foot charge for line extensions.[69]

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64 DEA Ex-3 at 57-58 (Heinen Direct)

65 Department Ex-9 at 30-31 (Bahn Direct)

66 OAG Ex- at 101-102 (Stevenson Direct)

67 Settlement at 22

68 DEA Ex-3 at 82-83 (Heinen Direct)

69 Department Ex-9 at 40-41 (Bahn Direct)

The OAG was concerned that existing customers continue to pay a subsidy to new customers for line extensions. The OAG views the proposal as an acceptable first step, and that for the next rate case the Cooperative make a policy to line extension charges to the actual costs imposed on the system.[70]

2. Decision Options

507. Approve the Line Extension charges as recommended by the ALJ. (ALJ, DEA, Department, OAG)

H. Service and Reconnection Charges

1. Introduction

Dakota Electric proposed changes to an array of special fees, including reconnection fees, because of its cost analysis. It proposed to increase the reconnection fee from $10 to $12.

The Department recommended approval of the service and reconnection charge increases.[71]

The OAG believed the $12 reconnection fee should be the only immediate fee, and that the Cooperative should help such members to get on a payment plan.

In the Settlement Parties agree that Dakota Electric will work with interested parties to develop modifications to its current policy requiring Residential members to pay a deposit in addition to the reconnection fee before reconnecting a member who has been disconnected for nonpayment.[72]The Parties also agree that Dakota Electric will implement changes as soon as practicable, including, if necessary, making a filing for approval with the Commission by February 26, 2026 to allow for Commission review and approval by May 1, 2026.

2. Decision Options

508. Approve the service and connection charges as recommended by the ALJ. (ALJ, DEA, Department, OAG)

509. Require Dakota Electric to implement changes as soon as practicable, including, if necessary, making a filing for approval with the Commission by February 26, 2026 to allow for Commission review and approval by May 1, 2026. (DEA, Department, OAG)

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[70] OAG Ex- at 94-96 (Stevenson Direct)

[71] Department Ex-9 at 46 (Bahn Direct)

[72] Settlement at 20-21.

I. Data Center Reporting

1. Introduction

The OAG noted that the introduction significant load from data centers between this rate case and the next rate case could alter its apportionment recommendation.[73]Dakota Electric could potentially add four data centers with a combined load of 1,600 MW, which would be almost four times the Cooperative's current system peak of 450 MW. The addition of data centers could result in under-forecasting sales and revenues and thus making the revenue deficiency larger than it is. Any new datacenters should pay not only its incremental costs of connecting and operating, but also its share of system costs. If Dakota Electric adds more load, say 50 MW, than it expects in this rate case, it should come in for a new rate case.

2. Settlement

The Parties agree that Dakota Electric will notify the Commission through a letter filing in this docket if it adds 50 MW or more of data center load before its next general rate case filing.[74]

3. Decision Options

510. Require Dakota Electric to notify the Commission through a letter filing in this docket if it adds 50 MW or more of data center load before its next general rate case filing. (DEA, OAG)

J. Idle Service Tariff

1. Introduction

Dakota Electric proposed the Idle Service Tariff for those members who have had a service or service extension which either has never been energized after construction or energized but no longer providing electric service to the member.[75]The Idle Service Tariff allows Dakota Electric to recover shared system costs from these members who have no meters to register usage. The Cooperative's proposed tariff is $24.25, which is based on the CCOSS minimum system cost for a residential member.

The Department recommended against approval since the alternatives of paying a monthly fee or removal of all existing equipment seemed unreasonable.[76]However, if the Commission were to approve this tariff, the charge should be no more than the monthly fixed charge for the residential & farm service (31) class.

2. Settlement

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[73] Ex-2 OAG at 74-78 (Stevenson Direct)

[74] Settlement at 20

[75] Ex. DEA-3 at 83-84 (Heinen Direct)

[76] Ex. DOC-9 at 42-45 and AB-1 (Bahn Direct)

The Parties agree that Dakota Electric's Idle Service Tariff be approved with the fixed monthly charge equal to $12.00.[77]

3. Decision Options

511. Approve the Idle Service Tariff with the fixed monthly charge equal to $12.00. (DEA, Department)

K. Other Miscellaneous Tariffs

1. Introduction

Dakota Electric proposed a number of minor, miscellaneous tariff modifications and changes in Workpaper 27, many of which were uncontested.[78],[79]The Department agreed on the revisions to minor service fees and had no comment on the minor proposed revisions in Workpaper 27.[80]

2. Decision Options

512. Approve proposed miscellaneous tariff changes listed in Workpaper 27. (DEA, Department)

L. ALJ Report

The ALJ noted the following in her findings:

> 38. Second, regarding revenue apportionment, the Settlement provides for a revenue apportionment with class-specific increases that results in a more moderate increase for the Residential and Small General Service classes than initially proposed by Dakota Electric, addressing concerns from public commenters about the size of the proposed Residential increase.
>
> 42. Sixth, as part of the Settlement, Dakota Electric agreed to work with interested parties to develop modifications to its current policy requiring Residential members to pay a deposit in addition to the reconnection fee before reconnecting a member who has been disconnected for nonpayment.
>
> 43. Seventh, as part of the Settlement, Dakota Electric agreed to notify the Commission through a letter filing in this docket if it adds 50 MW or more of data center load before its next general rate case filing.
>
> 44. Eighth, Dakota Electric also agreed, as part of the Settlement, to file its plan to

[77] Settlement at 18-19.

[78] Ex. DEA-6 at 85 (Heinen Direct).

[79] Ex. DEA-6 at Workpaper 27 (Proposed Miscellaneous Tariff Changes)

[80] Ex. DOC-9 at 45-46 (Bahn Direct)

educate members on the new Electric Vehicle (EV) peak hours as a compliance filing in this docket.

47. Finally, the Settlement resolves the miscellaneous tariff modifications proposed by Dakota Electric, which were generally not disputed.

50. The Settlement modifies the rate design proposed by the Cooperative by reducing the Residential and Small General Service class revenue increases and adopting a more moderate increase to the Residential and Farm Service fixed monthly customer charges.

M. Staff Comments

Staff has reviewed the settlement and finds the agreement on rate design to be reasonable.

X. GENERAL HOUSEKEEPING AND COMPLIANCE ISSUES

All the compliance filing requirements in the decision alternatives are standard rate case compliance items. These requirements ensure that Dakota Electric files various financial and rate design schedules that reflect the Commission's decision, revised tariff sheets, a draft customer notice, and a new base Resource and Tax Adjustment. An interim rate refund plan may not be necessary if the approved final rates are higher than interim rates.

Staff suggests the Commission in its order incorporate a set of financial summaries for Dakota Electric in this docket that includes: a schedule showing the calculation of the DEA's authorized cost of capital, a rate base summary, an operating income statement summary, a gross revenue deficiency calculation, and a statement of total allowed revenues.

Decision Options for General Housekeeping and Compliance Issues

901. State that the final order in this docket shall contain summary financial schedules including: a calculation of Dakota Electric's authorized cost of capital, a rate base summary, an operating income statement summary, a gross revenue deficiency calculation, and a statement of the total allowed revenues. Direct parties to work with Commission staff to prepare such schedules for inclusion in the Order, should modifications be necessary to reflect the Commission's final decision.

If the Commission adopts the Settlement with modifications and changes to any of the Settlement's financial schedules are necessary to reflect the Commission's final decision, decision option 902 should be selected.

902. Require Dakota Electric to make the following compliance filings within 30 days of the date of the final order in this docket:

a. Revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions herein, along with the proposed effective date, and

including the following information:

i. Breakdown of Total Operating Revenues by type;

ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to:
   1. Total revenue by customer class;
   2. Total number of customers, the customer charge and total customer charge revenue by customer class; and
   3. For each customer class, the total number of energy and demand related billing units, the per unit energy and demand cost of energy, and the total energy and demand related sales revenues.

iii. Revised tariff sheets incorporating authorized rate design decisions;

iv. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.

b. A revised base cost of energy, supporting schedules, and resource and tax adjustment tariffs to be in effect on the date final rates are implemented.

c. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.

d. If final authorized rates are lower than interim rates, a proposal to make refunds of interim rates consistent with the Commission's decision in this proceeding, to affected customers.

903. Authorize comments on all compliance filings within 30 days of the date they are filed. However, comments are not necessary on Dakota Electric's proposed customer notice.

904. Where not otherwise specified within the Commission's Order, adopt the ALJ's Findings of Fact, Conclusions of Law, and Recommendations. Delegate authority to the Executive Secretary to modify the ALJ Report if necessary to reflect the Commission's findings. (Staff)

XI. DECISION OPTIONS

ALJ Findings of Fact, Conclusions of Law, and Recommendations

1. Adopt the ALJ's Findings of Fact, Conclusions of Law and Recommendations, and approve the Settlement.

2. Accept and adopt the ALJ's Findings of Fact, Conclusions of Law and Recommendations and approve the Settlement with modification listed below.

3. Reject all of the ALJ's Findings of Fact, Conclusions of Law, and Recommendations.

Staff note: [If the Commission adopts Decision Option 1, the Settlement position on all of the following issues will be adopted by default, and the Commission can skip to the "General Housekeeping and Compliance Issues" starting with Decision Option 901. If the Commission adopts Decision Option 2, it should select Decision Options only for issues on which the Commission's decision differs from the Settlement.]

Financial Issues

Employee Compensation

101. Approve Dakota Electric salary expense of $11,983,503 for test-year. (Department, OAG, Dakota Electric)

102 Disallow Dakota Electric other pay expense of $243,453 for test-year. (Department, OAG, Dakota Electric))

103 Approve Dakota Electric salary expense of $12,683,502.75 for test-year. (Dakota Electric Initial Filing)

104 Approve Dakota Electric other pay expense of $545,709.21 for test-year. (Dakota Electric Initial Filing)

Employee Awards and Gifts

105 Disallow Dakota Electric recovery of $23,539 in recreation and entertainment expense. (OAG, Dakota Electric, ALJ)

106 Disallow Dakota Electric recovery of $45,472in employee appreciation gifts, celebrations, and new employee welcome lunches expenses. (OAG, DEA, ALJ)

107 Allow Dakota Electric to recover recreation, entertainment, employee appreciation gifts, celebrations and new employee welcome lunch expense as initially filed. (DEA Initial Filing)

Payroll Taxes

108 Disallow recovery of $257,249 in payroll taxes for test year. (Department, DEA, ALJ)

109 Allow Dakota Electric to recover test year payroll taxes of $1,697,832. (DEA Initial Filing)

Benefits

110 Disallow recovery of benefits in the amounts of Life insurance $48,788, Workers' Compensation $45,000, Post-Employment 106 Benefit $85,000, and Pension Expense $115,095. (Department, DEA, ALJ)

111 Allow Dakota Electric to recover employee benefits as initially filed. (DEA Initial Filing)

Utility Service Revenue

112 Require Dakota Electric to increase utility service revenue by $70,000. (Department, DEA, ALJ)

113 Allow Dakota Electric to use initial amount for utility service revenue. (DEA Initial Filing)

Charges and Fees Revenue

114 Require Dakota Electric to increase charges and fees revenue by $70,000. (The Department, Dakota Electric, All Parties)

115 Allow Dakota Electric to use initial amount for charges and fees revenue. (Dakota Electric

Legacy Meters

116 Require Dakota Electric to reduce test year depreciation expense by $465,604 and increase accumulated depreciation by $465,604, resulting in an increase to test year revenue deficiency of $23,932, for a net reduction to the revenue deficiency of $441,672 to reflect the removal of legacy meters from the test year. (Department, DEA, ALJ)

117 Allow Dakota Electric to recover depreciation and amortization expense of $14,089,060 in test year. (DEA Initial Filing)

Bad Debt Expense

118 Require Dakota Electric to reduce test year bad debt expense by $135,000. (Department, DEA, ALJ)

119 Allow Dakota Electric to recover bad debt expense of $743,567 for test year as initially filed. (DEA Initial Filing)

MREA and NRECA Dues

120 Require Dakota Electric to reduce test year expense by $57,249 related to a portion of MREA dues and $93,747 the full amount of NRECA dues included in the 2023 test year. (OAG, DEA, ALJ)

121 Allow Dakota Electric to recover dues expense of $376,734 for test year as initially filed. (DEA Initial Filing)

Chamber of Commerce

122 Require Dakota Electric to reduce test year expense by $6,344 related to a portion of dues for Chambers of Commerce and Greater MSP. (OAG, DEA, ALJ)

123 Allow Dakota Electric to recover Chambers of Commerce and Greater MSP dues expense of $25,375 for test year as initially filed. (DEA Initial Filing)

Charitable Contributions

124 Require Dakota Electric to reduce test year expense by $32,687 related charitable contributions. (OAG, DEA, ALJ)

125 Require Dakota Electric in future rate cases to confirm charitable contributions are registered in accordance with Minn. Stat. Ch. 309 or that the charity is exempt from registration with Minnesota Attorney General's Office before seeking rate recovery. (OAG, DEA, ALJ)

126 Allow Dakota Electric to recover charitable contribution as initially filed. (DEA Initial Filing)

Community Events

127 Require Dakota Electric to reduce test year expense by $7,008 related to a portion of community events. (OAG, DEA, ALJ)

128 Allow Dakota Electric to recover community events expense of $7,729 for test year as initially filed. (DEA Initial Filing)

Cash Working Capital

129 Approve the methodology used to calculate the cash working capital included in rate

base. (Department, DEA, ALJ)

130 Allow Dakota Electric to use original methodology on working capital. (DEA Initial Filing)

Travel and Entertainment – Alcoholic Beverages

131 Disallow recovery of all alcoholic-beverage expense in 2023 test year and in DEA future rate cases. (OAG, DEA, ALJ)

132 Allow Dakota Electric to recover alcoholic-beverage expense in 2023 test year and future rate cases (DEA Initial Filing)

Base Cost of Energy

133 Require Dakota Electric will file a revised base cost of energy, supporting schedules, and resource and tax adjustment tariffs to be in effect with the implementation of final rates in this case. (DEA, ALJ)

134 Allow Dakota Electric to not to revise base cost of energy. (DEA Initial Filing)

Class Cost of Service Study

201 Approve Dakota Electric's corrected CCOSS as reasonable as recommended by the ALJ (ALJ, DEA, Department, OAG)

Cost Of Capital

301 Adopt The Agreed Upon Rate of Return. (ALJ, Department, DEA, OAG)

Sales Forecast

401 Approve Dakota Electric's proposed test-year customer count and energy sales volumes for all classes of customers with the exception of the Residential and Farm Service class. For the Residential and Farm Service class, approve the adjustments recommended by the Department and accepted by Dakota Electric. (ALJ, DEA, Department)

Rate Design

Revenue Apportionment

501. Approve the revenue allocation as recommended by the ALJ. (ALJ, DEA, Department, OAG)

Customer Charges

502. Approve the customer charges as recommended by the ALJ. (ALJ, DEA, Department, OAG)

Residential Time of Day Tariff

503. Approve the Residential Time of Day Tariff as recommended by the ALJ. (ALJ, DEA)

Standby Service

504**.** Approve the Standby rates as recommended by the ALJ. (ALJ, DEA, Department)

Electric Vehicles Rates

505. Approve the Electric Vehicle rates as recommended by the ALJ. (ALJ, DEA, Department, OAG)

506. Approve the plan educating Electric Vehicle customers on the new peak charging hours. (ALJ, DEA, Department, OAG)

Line Extension Charges

507. Approve the Line Extension charges as recommended by the ALJ. (ALJ, DEA, Department, OAG)

Service and Connection Charges

508**.** Approve the service and connection charges as recommended by the ALJ. (ALJ, DEA, Department, OAG)

509. Require Dakota Electric to implement changes as soon as practicable, including, if necessary, making a filing for approval with the Commission by February 26, 2026 to allow for Commission review and approval by May 1, 2026. (DEA, Department, OAG)

Data Center Reporting

510. Require Dakota Electric to notify the Commission through a letter filing in this docket if it adds 50 MW or more of data center load before its next general rate case filing. (DEA, OAG)

Idle Service Tariff

511. Approve the Idle Service Tariff with the fixed monthly charge equal to $12.00. (DEA, Department)

Other Miscellaneous Tariffs

512. Approve proposed miscellaneous tariff changes listed in Workpaper 27. (DEA, Department)

General Housekeeping and Compliance Issues

901 Require Dakota Electric to prepare summary financial schedules including: a calculation of Dakota electric's authorized cost of capital, a rate base summary, an operating income statement summary, a gross revenue deficiency calculation, and a statement of the total allowed revenues. Require Settlement Parties to work with commission staff to prepare such schedules for inclusion in the order, should modifications be necessary to reflect the commission's final decision.

902. Require Dakota Electric to file the following within 30 days of the order:

A. Revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions herein, along with the proposed effective date, and including the following information:

i. Breakdown of Total Operating Revenues by type;

ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to:

1) Total revenue by customer class;
2) Total number of customers, the customer charge and total customer charge revenue by class; and
3) For each customer class, the total number of energy and demand related billing units, the per unit energy and demand cost of energy, and the total energy and demand related sales revenues.

iii. Revised tariff sheets incorporating authorized rate design decisions;

iv. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.

B. A revised base cost of energy supporting schedules, and resource and tax adjustment tariffs to be in effect on the date final rates are implemented.

C. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.

D. If final authorized rates are lower than interim rates, a proposal to make refunds of interim rates consistent with the Commission's decision in this proceeding, to affected customers.

903. Require that any comments on compliance filings be filed within 30 days of the compliance filing. Delegate authority to the Executive Secretary to modify this comment deadline via notice.

904. Where not otherwise specified within the Commission's Order, adopt the ALJ's Findings of Fact, Conclusions of Law, and Recommendations. Delegate authority to the Executive Secretary to modify the ALJ Report if necessary to reflect the Commission's findings. (Staff)

XII. APPENDIX A – REFERENCES TO THE RECORD

Financial Issues

135 Employee Compensation

ALJ Report ¶ 41
Settlement at 3-4
Ex. DEA-3 15-16 (Heinen Direct)
Ex. DEA-4, Exhibit 1 at 2-5 (Statement of Operations – Present Rates)
Ex. DEA-6, Workpaper 3 (Accounting System Description and 2023 Form 7 Income Statement),
Workpaper 4 (2024 Budget (2022 & 2023 Actual)), Workpaper 15F (Top Ten Compensation), Workpaper 16 (Test Year Adjustments Bridge Schedule)
Ex. DOC-1 at 18-33 and MBK-D-9 through MBK-D-21 (Kehrwald Direct and Attachments)
Ex. OAG-1 at 11-15, SL-D-12 through SL-D-14 (Lee Direct and Schedules)

135 Employee Awards and Gifts

ALJ Report ¶ 41
Settlement at 4-5
Ex. DEA-6 at Workpaper 15G and 15H (Top Ten Expenses and Recreation and Entertainment)
Ex. OAG-1 at 11-15 and SL-D-10 through SL-D-11 (Lee Direct and Schedules)

136 Payroll Taxes

Settlement at 5
Ex. DEA-4, Exhibit 1, page 6 (Statement of Operations - Present Rates)
Ex. DEA-6 at Workpaper 4 page 2 of 5 (2024 Budget (2022 & 2023 Actual))
Ex. DOC-1 at 33-35, MBK-D-10 and MBK-D-22 (Kehrwald Direct Attachments)

137 Benefits

ALJ Report ¶ 41
Settlement at 5-6
Ex. DEA-4, Exhibit 1 page 2, 6-7 (Statement of Operations - Present Rates), Exhibit 3 (Cost of Service Analysis)
Ex. DEA-6, Workpaper 2 (Audited 2023 Financials and 2023 Annual Report), Workpaper 3 (Accounting System Description and 2023 Form 7 Income Statement), Workpaper 4 (2024 Budget (2022 & 2023 Actual)), Workpaper 16 (Test Year Adjustments Bridge Schedule)
Ex. DOC-1 at 34-44 and MBK-D-10, MBK-D-13, MBK-D-23, and MBK-D-24 (Kehrwald Direct and
Attachments)

138 Utility Service Revenue

ALJ Report ¶ 41
Settlement at 6
Ex. DEA-4, Exhibit 1 (Statement of Operations – Present Rates), Exhibit 2 (Determination of Revenue Requirements), Exhibit 3 (Cost of Service Analysis), Exhibit 5 (Statement of Operations - Proposed Rates)
Ex. DEA-6, Workpaper 4 (2024 Budget (2022 & 2023 Actual))
Ex. DOC-6 at 3-7 and HDJ-D-1 through HDJ-D-2 (Jones Direct and Attachments)

139 Charges and Fees

Settlement at 7
Ex. DEA-4, Exhibit 1 (Statement of Operations – Present Rates), Exhibit 2 (Determination of Revenue Requirements), Exhibit 3 (Cost of Service Analysis), Exhibit 5 (Statement of Operations - Proposed Rates), and Exhibit 10 (Special Fees and Charges)
Ex. DOC-6 at 3-5, 7-10 and HDJ-D-2 through HDJ-D-4 (Jones Direct and Attachments)

140 Legacy Meters

Settlement at 7-8
Ex. DEA-6 at Workpaper 8 (Depreciation Summary)
Ex. DOC-7 at 3-6 and MWB-D-1 through MWB-D-3 (Bologna Direct and Attachments)

141 Bad Debt Expense

Settlement at 8
Ex. DEA-6, Workpaper 4, page 4 (2024 Budget (2022 & 2023 Actual))
Ex. DOC-7 at 6-8 and MBW-D-4 through MBW-D-6 (Bologna Direct and Attachments)

142 MREA and NRECA

ALJ Report ¶ 41
Settlement at 9-10
Ex. DEA-6, Workpaper 20, page 1 of 2 (Organization Dues)
Ex. OAG-1 at 2-8 and SL-D-1 through SL-D-6 (Lee Direct and Schedules)

143 Chamber of Commerce

Settlement at 10-11
Ex. DEA-6 at Workpaper 20 (Organizational Dues)
Ex. OAG-1 at 9-11, SL-D-8 and SL-D-9 (Lee Direct and Schedules)

144 Charitable Contributions

ALJ Report ¶ 45
Ex. DEA-6 at Workpaper 19 (Donations/Charitable Contributions)
Ex. OAG-1 at 15-23, SL-D-15 through SL-D-19 (Lee Direct and Schedules)
Settlement at 11-12

145 Community Events

Settlement at 12
Ex.DEA-6 at Workpaper 15D (Community Events Expenses)
Ex. OAG-1 at 24-27, SL-D-20 through SL-D-22 (Lee Direct and Schedules)

146 Cash Working Capital

Settlement at 12-13
Ex. DEA-4, Exhibit 2 at 2 (Determination of Revenue Requirements), Exhibit 9 (Summary of Lead-Lag Study)
Ex. DEA-6 at Workpaper 6 (Lead Lag Study Detail)
Ex. DOC-1 at 44-45 and MBK-D-4 (Kehrwald Direct and Attachments)

147 Travel and Entertainment - Alcoholic Beverages

Ex. DEA-6 at Workpaper 15 (Travel, Entertainment, and Related Employee Expenses)
Ex. OAG-1 at 27-29, SL-D-14, Schedule SL-D-23, and SL-D-24 (Lee Direct and Schedules)
Settlement at 19

148 Base Cost of Energy

Settlement at 13-14
Ex. DEA-4, Exhibit 12 (Base Calculations for Resource and Tax Adjustment)

Class Cost of Service Study

ALJ Report ¶¶ 22, 39
Settlement at 14
Ex. DEA-3 at 26, 39, 40 (Heinen Direct)
Ex. DEA-6 (Workpaper 21)
Ex. DOC-8 at 39 (Zajicek Direct)
Ex. OAG-2 at 57-62(Stevenson Direct)

Cost of Capital

ALJ Report ¶¶ 40, 51
DEA Ex. 2 at 18-24 (Heinen Direct)
DOC Ex. 2 at 5-8 (Kundert Direct)

Sales Forecast

Settlement at 8-9
Ex. DEA-6, Initial Filing, Vol. 2, Workpaper 13, page 1, Sales History and Forecasted Test Year Normalization
Ex. DOC-5 at 12-13 (Zhang Direct)

Rate Design

1 Apportionment of Class Revenue Responsibility

ALJ Report ¶¶ 23, 50
Settlement at 17-18, and Attachment 2, page 1 of 7
Ex. DEA-1, Exhibit 1 at 12 (Heinen Direct)
Ex. DEA-3 at 13, 50-52, 51-80 (Heinen Direct)
Ex DEA-6 (Workpaper 26)
Ex. DOC-9 at 47-48 (Bahn Direct)
Ex. OAG-2 at 108-110 (Stevenson Direct)

2 Fixed Monthly Customer Charge

ALJ Report ¶¶ 50
Settlement at 17
DEA Ex-3 at 51-80, 57-58, 77, 82-83 (Heinen Direct)
DEA Ex-6 (Workpaper 26)
Ex-9 Department at 9, 28-29, 30-31, 40-41, 46 (Bahn Direct)
Ex-2 OAG at 94-96, 101, 102, 109 (Stevenson Direct)

3 Residential Time of Day Rates

Ex DOC-9 at 29 (Bahn Direct)

4 Standby Service Rate

Ex DEA-3 at 77 (Heinen Direct)
Ex DOC-9 at 37-38 (Bahn Direct)

5 Electric Vehicle Charges

Settlement at 22
Ex DEA-3 at 57-58 (Heinen Direct)
Ex DOC-9 at 30-31 (Bahn Direct)
Ex OAG-2 at 101-102 (Stevenson Direct

6 Line Extension Charges

Ex DEA -3 at 82-83 (Heinen Direct)
Ex DOC-9 at 40-41 (Bahn Direct)
Ex OAG -2 at 94-96 (Stevenson Direct)

7 Service and Reconnection Charges

Settlement at 20-21
Ex DOC-9 at 46 (Bahn Direct)

8 Data Center reporting

Settlement at 20
Ex OAG-2 at 74-78 (Stevenson Direct)

9 Idle Service Tariff

Settlement at 18-19
Ex. DEA-3 at 83-84 (Heinen Direct)
Ex. DOC-9 at 42-45 and AB-1 (Bahn Direct)

10 Other Miscellaneous Tariff

Settlement at 18-19
Ex. DEA -6 at 85 (Heinen Direct)
Ex. DEA-6 at Workpaper 27 (Proposed Miscellaneous Tariff Changes)
Ex. DOC-9 at 45-46 (Bahn Direct)