Minnesota Public Utilities Commission
Staff Briefing Papers

Meeting Date: April 23, 2015 .... **Agenda Item # 5****

Company: Dakota Electric Association

Docket No. E-111/GR-14-482
In the Matter of the Application by Dakota Electric Association for Authority to Increase Rates for Electric Service in Minnesota

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Issues: Should the Commission adopt the recommendations in the ALJ's Report? Should the Commission adopt the settlement agreement, as amended, between Dakota Electric Association and the Minnesota Department of Commerce? If neither, what level of revenue is appropriate for the Association during the test year? How should that revenue be collected from its customers?

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Ganesh Krishnan (Sales Forecast & Rate of Return) 201-2215
Dorothy Morrissey (Financial) 201-2232
Robert Harding (Procedural)... 201-2237

Relevant Documents

<u>Settlement Agreement</u>
Settlement Agreement between DEA and the Department (OAH Exhibit 128) .... Jan. 5, 2015
Amendment to Settlement Agreement (OAH Exhibit 128A) .... Jan. 20, 2015

<u>Post-Hearing Summary of Disputed and Resolved Issues</u>
Dakota Electric (DEA)... Jan. 9, 2015

<u>Initial Briefs</u>
Department of Commerce (Department) .... Jan. 20, 2015
Office of Attorney General-Antitrust & Utilities Division (OAG-AUD) .... Jan. 20, 2015
Dakota Electric (DEA)... Jan. 21, 2015

<u>Reply Briefs & Proposed Findings of Fact</u>
Department .... Jan. 30, 2015
OAG-AUD... Jan. 30, 2015
DEA .... Jan. 30, 2015

ALJ Report

Findings of Fact, Conclusions of Law and Recommendation .... Mar. 2, 2015
Master Exhibit List .... Feb. 23, 2015
DEA - Schedules Reflecting ALJ Recommendation .... Mar. 9, 2015
Department - Comments on DEA's Schedules .... Mar. 11, 2015

Exceptions to the ALJ Report

OAG-AUD.. Mar. 12, 2015
DEA .... Mar. 12, 2015

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

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Table of Contents

Statement of the Issues

Should the Commission adopt the recommendations in the ALJ's Report? Should the Commission adopt the settlement agreement, as amended, between Dakota Electric Association and the Minnesota Department of Commerce? If neither, what level of revenue is appropriate for the Association during the test year? How should that revenue be collected from its customers?

Introduction

Dakota Electric Association (DEA) serves approximately 103,000 customers (members) and has projected total annual electricity sales to be approximately 1,898,207 MWh.[1] DEA is an electric distribution only utility. It does not generate electricity nor owns any high voltage transmission lines. Instead, it purchases its wholesale power and related transmission services from Great River Energy (GRE) of Maple Grove, Minnesota.[2]

Dakota Electric Association requested a $4.189 million (or approximately 2.1 percent) rate increase. Based on DEA's March 9, 2015 compliance filing, the various outcomes, should the Commission adopt one of them in its entirety, would result in the following rate increases:

1) the recommendations in the ALJ Report without modification (corrective or otherwise), would produce a revenue increase of $4.027 million (a rate increase of approximately 2.0 percent);
2) the recommendations in the ALJ Report, modified to correct the ALJ's wage adjustment as identified by DEA, would produce a revenue increase of $3.767 million (a rate increase of approximately 1.89 percent); or
3) the settlement agreement between DEA and the Department, as amended, would authorize DEA's full initial request for a $4.189 million (or approximately 2.1 percent) rate increase.

Each of these rate increase outcomes is based on the parties' resolved return on common equity of 4.28 percent and overall rate of return on rate base of 6.47 percent.[3] These outcomes are summarized in the table below:

Table 1

Some Options	Rate Increase	$ Change to DEA's Request	Rate Increase %
	($ in millions)		
DEA's Initial Request	$4.189	0	2.1%
ALJ Report (w/ corrected figure)	$3.767	($0.422)	1.89%
ALJ Report (as is)	$4.027	($0.162)	2.0%
Settlement Agreement	$4.189	0	2.1%

[1] Ex. 102, Schedule DEA-1 at 12.
[2] Ex. 100 at 2 (Miller Direct)
[3] This 6.47% is based on the rate base of $171,181.006. If this rate base changes, so will the rate of return on rate base.

The main issue before the Commission is whether to adopt the ALJ's Report, including her recommendations regarding the disputed issues. The following is a list of some of the disputed issues in this case which require a decision.

- Financial adjustment for staffing changes
- Travel, Entertainment and Employee Expenses
- Class Cost of Service Study (CCOSS)
- Class revenue apportionment
- Residential & Farm and Small General Service monthly customer charge

If the Commission does not accept the ALJ's Report (and recommendations) in its entirety, or the settlement agreement between DEA and the Department, then, based on Commission modifications, it will need to decide the Cooperative's appropriate test year revenue level and how that revenue should be collected from customers.

Background

On July 2, 2014, Dakota Electric Association (DEA, Dakota, Cooperative or Association) filed a general rate case with the Minnesota Public Utilities Commission (Commission) (Docket No. E-111/GR-14-482). The Cooperative requested an increase of $4.189 million, or 2.1 percent, in its Minnesota retail electric rates, effective September 11, 2014. The increase is based on a historical 2013 test-year, adjusted for known and measureable changes, and a proposed rate of return on total equity capitalization of 4.49 percent to develop 2014 revenue requirements.

On August 29, 2014, the Commission issued three Orders.[4] In those Orders, the Commission accepted DEA's filing, suspended the proposed final rates until the end of this case, and set this matter for contested case hearing. The Commission also authorized an interim rate increase of approximately $2,982,000 per year, or approximately 1.5 percent, effective August 31, 2014 and subject to refund. The Commission approved DEA's proposal to forgo its statutory right to begin charging interim rates 60 days from the date of its general rate-case filing, to instead wait to begin charging interim rates for service rendered on and after September 11.

Administrative Law Judge (ALJ) LauraSue Schlatter of the Minnesota Office of Administrative Hearings (OAH) was assigned to conduct the case.

The parties in this case are:

- Dakota Electric Association (DEA, Dakota, Cooperative or Association)
- Minnesota Department of Commerce-Division of Energy Resources (the Department or DOC)
- Minnesota Office of the Attorney General-Antitrust and Utilities Division (OAG-AUD or OAG)

[4] ORDER ACCEPTING FILING AND SUSPENDING RATES; NOTICE AND ORDER FOR HEARING; and ORDER SETTING INTERIM RATES (this docket)

DEA, the Department, and the OAG submitted prefiled testimony in advance of the evidentiary hearings. (Copies of the prefiled testimony are available electronically through the eDockets system.)

On December 2, 2014, Judge Schlatter held two public hearings, with attendance as follows:

Table 2

Location, date, and time	Members of the public in attendance	Members of the public who spoke
Apple Valley Senior Center Apple Valley – December 2, 2014 (2:00 p.m.)	5	4
Dakota Energy Association Farmington – December 2, 2014 (7:00 p.m.)	0	0

In addition, seven written public comments were received by the ALJ and the Commission combined. Each of the seven individuals who submitted written comments opposed DEA's request for a rate increase.[5] Copies of the public hearing transcripts and the written public comments are available electronically.

On December 18, 2014, the evidentiary hearings were held in St. Paul. A copy of the evidentiary hearing transcript is also available electronically.

On January 9, 2015, DEA submitted a matrix of disputed and resolved issues.

On January 20, 2015, DEA and the Department filed their Amended Settlement (Exhibit 128A). The two parties agreed to a rate base of $171,181,006. The amendment arose because the Department acknowledged an arithmetical error in the calculation of the return on equity and corrected it from 4.35 percent to 4.28 percent. The resulting overall rate of return on rate base was appropriately revised to 6.47 percent.

On January 20, 2015, the Department and the OAG-AUD filed initial briefs. DEA e-filed its initial brief on January 21, 2015.

On January 30, 2015, DEA, the Department, and the OAG-AUD filed reply briefs and their proposed findings of fact.

On March 2, 2015, Administrative Law Judge LauraSue Schlatter (ALJ) issued her Findings of Fact, Conclusions of Law and Recommendations (ALJ Report). For reference purposes, there is a master exhibit list that identifies all of the items in the record by exhibit number which are referred to in her Report. Some resolutions as recommended by the ALJ differ from the Settlement Agreement.

On March 9, 2015, Dakota Electric submitted financial schedules that reflect its interpretation of the test-year revenue requirement and rate design recommended by the ALJ. Dakota believes the

[5] ALJ Report Finding No. 18.

ALJ’s reported wage annualization adjustment figure (ALJ Report paragraph 68) should be modified to reflect the intent described within the report. Dakota Electric discussed its proposed corrections to the figure in the ALJ Finding 68 with the OAG and the Department. All parties concurred.[6] The effect of this correction lowered the revenue requirement, commensurate with the ALJ’s findings.

On March 11, 2015, the Department’s letter confirmed its agreement with DEA’s schedules and modification to the ALJ’s figure. This letter also informed the Commission of a recently discovered calculation error with the Department’s recommended non-operating income adjustment, upon which the ALJ had relied (ALJ Report paragraph 25).[7] The Department recommended that the relatively small correction amounting to a $10,000 increase to non-operating income should be used in DEA’s final compliance filing. (A decision alternative captures this request.)

On March 12, 2015, DEA and the OAG-AUD filed exceptions to the ALJ Report. The Department did not file exceptions to the ALJ Report.

Issues Set for Hearing

In its August 29, 2014 Notice and Order for Hearing, the Commission identified the following issues for parties to address in this proceeding:

1. Is the test year revenue increase sought by DEA reasonable or will it result in unreasonable and excessive earnings by the Cooperative?
2. Is the rate design proposed by DEA reasonable?
3. Are DEA's proposed capital structure, cost of capital, and return on equity reasonable?
4. Has DEA appropriately matched the power cost revenues and expenses in its pro forma test year?

Staff believes each of these items has been addressed in this proceeding.

[6] The Department filed letter on March 11, 2015. The OAG’s Exceptions, filed March 12, 2015, relays its agreement with the correction.

[7] Exhibit 128 at 5 (Settlement Agreement). The agreement indicated the non-operating income of $399,147 be reduced by $272,889 to $116,258. However, $399,147 - $272,889 equals $126,258. Therefore the recommended non-operating income should be increased by $10,000.

Extension of the Deadline for the Commission to Issue its Final Determination

PUC Staff: Robert Harding

Statement of the Issue

Should the Commission extend the suspension period for proposed final rates to allow the Commission additional time to prepare and issue its final determination, pursuant to Minn. Stat. § 216B.16, Subd. 2?

The statutory deadline for the Commission to issue its final order in this matter is ten months from the date this filing was found to be substantially complete, pursuant to Minn. Stat. §216B.16, Subd. 2(a). This case was accepted as of July 2, 2014 and the Commission's deadline for issuing an order is May 2, 2015, which is a Saturday. Because this deadline falls on a Saturday, the Commission has until the following Monday, May 4 to issue its final determination (Order).

Because the Commission has another general rate case pending, the Xcel Energy (Xcel) electric rate case, in Docket E-002/GR-13-868, the Commission has the authority to extend the deadline for issuing its final determination up to ninety days (i.e. until Aug. 2), pursuant to Minn. Stat. §216B.16, Subd. 2(f):

> If the commission finds that it has insufficient time during the suspension period to make a final determination of a case involving changes in general rates because of the need to make a final determination of any pending case involving changes in general rates under this section or section 237.075, the commission may extend the suspension period to allow up to a total of 90 additional calendar days to make the final determination. An extension of the suspension period under this paragraph does not alter the setting of interim rates under subdivision 3.

The Commission heard the Xcel rate case on March 19 and 26 and expects to issue its final determination on, or about, May 8, 2015.

Absent an extension of time in the Dakota Electric rate case the Commission will have at most eleven calendar days (including two weekends) to prepare the Order. Staff does not believe that schedule allows a sufficient amount of time to prepare the Order concurrently with the preparation of the Order in the Xcel rate case. Staff believes extra time in the Dakota Electric rate case would allow for more flexible scheduling and additional time for the Commission to issue its decision.

Staff also notes that Dakota Electric offered to waive its right to decision within ten months and requested a final Commission Order in early July 2015. In its July 2, 2014 transmittal letter, Dakota Electric stated that

> We request implementation of the proposed rates within 10 months of the date of Application. However, we recognize that there are presently multiple general rate filings before the Commission. Accordingly, Dakota Electric is willing to provide a limited waiver of the 10 month statutory timeframe, extending the disposition of this case an additional two months, and requests that a Commission Order is received at the beginning of July 2015.

Staff believes the Commission may want to consider accepting Dakota Electric's offer of a limited statutory waiver and plan on issuing its order by early July as the co-op proposed. Staff believes that would be a workable schedule and recommends the Commission find that it will have insufficient time under the standard ten-month time frame to make a determination on final rates in the instant Dakota Electric rate case because of the need to issue a final determination concurrently in the pending Xcel electric rate case.

Decision Alternatives - Extension of the suspension period for proposed final rates

(Note: The following decision alternatives correspond to 2:A-B in the Deliberation Outline, p. 1.)

A. Extend the suspension period for proposed final rates until the Commission issues its final determination in this matter. Find the Commission has insufficient time to make a final determination if the rates are suspended for a 10-month suspension period because of the need to make a final determination in another pending case (the Xcel Electric rate case, in Docket E-002/GR-13-868) involving changes in general rates. Accept Dakota Electric's offer of a limited statutory waiver and plan on issuing its order by early July, **or**

B. Extend the suspension period for proposed final rates in this matter for the same reasons as described in the first alternative but for a different or specific length of time not to exceed ninety days.

Staffing Changes

PUC Staff: Dorothy Morrissey

Statement of the Issues

Should the Commission allow the wage annualization adjustment for existing positions that were vacant for part of the year? Should the Commission approve the cost recovery of an incremental position, filled, in the test-year? Should the Commission permit cost recovery for employee hours formerly allocated to discontinued operations?

Introduction

DEA requested a salaries/wages (payroll) expense recovery of $15,176,774 for 2014 pro forma test year.[8] DEA based its request by applying several adjustments to its 2013 actual costs. These adjustments included general wage increases, normalizing the capital and expense ratios for test year labor costs, new position salary costs, annualizing costs of existing positions that were vacant for part of the year and an adjustment for atypical storm labor costs.

Employee benefit costs are often expressed as a percentage of payroll (i.e., a payroll loading factor). In its filing, for each DEA-adjustment to payroll costs, there is a corresponding benefit cost adjustment. For 2014, DEA indicated its loading factor was 48.34 percent of payroll.[9]

DEA's payroll expense request is a 7.69 percent increase over the prior year's actual expensed payroll. The OAG took issue with two payroll adjustments designated as "Staffing Changes": wages for the new position and the annualized cost adjustment of existing positions that were vacant for part of the year.[10] The OAG also has concerns with increased labor hours/cost being absorbed by the utility as a consequence of discontinued operations.

OAG

Excluding the purchased power expense category, compensation-related increases (i.e., payroll and employee benefits) account for 96.6% of the test year operating expense increase (or net test-year operating adjustments). The OAG did not object to the compensation level of any specific position, but had concerns with the total level of test year payroll expenses as compared to the historical average.

Annualizing Payroll Costs of Existing Positions' Part-Year Vacancies
(Disputed: a $397,225 wage expense increase and a corresponding benefit cost increase of $192,019 for a total revenue requirement of $589,244.)

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[8] Ex. 102, Schedule DEA-1 at 7 (Larson Direct)
[9] Ex. 102, Schedule DEA-1 at 6 (Larson Direct)
[10] Ex. 102, Schedule DEA-1 at 5 (Larson Direct)

The OAG examined DEA's employee headcount from 2011 to 2013 and found that it remained flat.[11]

Table 3

Department	2011	2012	2013
Management Services	7	7	7
Financial & Information Services	41	41	41
Energy & Member Services	32	32	32
Engineering Services	46	45	45
Utility Services	70	70	70
Total Full Time Employees	196	195	195

The OAG also observed that DEA's payroll expense amount was relatively flat over the years 2010 to 2013.

Table 4

Year	Expensed Payroll
2010 actual	$14,069,983
2011 actual	$14,068,038
2012 actual	$14,030,172
2013 actual	$14,093,131
Average from 2010-2013	$14,065,331

The OAG stated that the adjustment to annualize pay of existing positions that were vacant part of the year appeared to produce an above average expense (when compared to the past four years). Furthermore, in response to an information request, DEA indicated a lapse generally occurs when filling vacated positions.[12] The OAG concluded that this adjustment only captures the full cost of positions that were partially filled during the year and fails to recognize the payroll cost savings from the temporary vacancies of positions.[13] Given these facts, the OAG determined that DEA's adjustment to annualize pay for these positions, and the corresponding benefit cost adjustment, would inflate test year operating costs and recommended that the adjustment be disallowed. The OAG reasoned that a normal level of employee turnover is inherent with normal operations; and conversely, inflated test year costs would not be representative of a normalized level for payroll and benefit expenses.

The OAG argued that DEA's assumption that all 196 of its positions will be filled going forward without interruption is unreasonable.[14] On the contrary, the fact that DEA's actual payroll expenses have remained so consistent since 2010 demonstrates that it is typical for some positions to be vacant for at least part of any given year. The OAG stated that DEA must show

[11] Ex. 203 at 5-6 and Schedule SL-5 (Lee Direct)
[12] Ex. 203 at 6 and Schedule SL-6 (Lee Direct)
[13] Ex. 205 at 5 (Lee Surrebuttal)
[14] OAG Initial Brief at 6

that it is aware of measurable payroll increases that will occur after the test year, or that its test year is not representative because it is regular for DEA to fill all of its positions. The OAG believes DEA has not made its case on either issue.

Incremental Position

(Disputed: a $68,210 wage expense increase and a corresponding benefit cost increase of $32,973 for a total revenue requirement of $101,183.)

The OAG recommended disallowing test year recovery cost of an incremental position (for a powerline design technician[15]) and its related benefit costs. The OAG stated that there were no known and measurable adjustments or other information indicating that DEA's operations were changing; therefore the incremental position appeared to inflate compensation expenses.[16]

The OAG stated that the combined effect of the new position ($101,183) and the annualizing of pay for existing positions' part-year vacancies ($589,244) produce a 4.89 percent test year increase in DEA's payroll expense over its historical [test year].[17,18] The impact is significantly larger than the experienced percentage increase of any recent year, as shown below (OAG titled Table 3)[19]:

Table 5

TABLE 3			
Year	Payroll Expense	$ change over (under)	% change over (under)
2010 actual	$14,069,983		
2011 actual	$14,068,038	($1,945)	(0.01%)
2012 actual	$14,030,172	($37,866)	(0.27%)
2013 actual / Historical Test Year	$14,093,131	$62,959	0.45%
Test Year (2013 actual plus compensation adjustments for staffing changes)	$14,783,558	$690,427	4.89%

The OAG emphasized that this 4.89 percent increase does not include the impact of DEA's other proposed payroll adjustments (e.g., the three percent general wage increase).

Other – Support Hours Formerly Provided to Discontinued Operations

DEA has a non-regulated subsidiary, Energy Alternatives Parent, Inc. (EAI). DEA's labor costs are allocated to its subsidiaries, however, the amount of labor directed to service EAI lessened in 2013 as result of EAI's divestitures of membership interests in leasing and wholesale generation businesses in 2012. The decrease in the number of hours spent by DEA staff to support the

15 Ex. 102, Schedule DEA-1 at 5 (Larson Direct)
16 Ex. 203 at 7 (Lee Direct)
17 Ex. 204 at 4-5 (Lee Surrebuttal)
18 Staff notes that the OAG included benefit cost increase dollars of $224,992 (part of the $690,427) in its computation of 4.89% increase. However, the $14,093,127 amount does not include benefits, only salary/wage dollars. (Evidentiary Hearing Tr. at 38, lns.17-19, Larson). The staffing change wage increase totals $465,435 and it would calculate to be a 3.3% increase over historical payroll expense amount, rather than a 4.89% increase.
19 Ex. 204 at 6 (Lee Surrebuttal)

subsidiaries has translated into additional labor capacity by the same staff to support DEA utility operations. The OAG quantified that an additional 842 hours are now charged to DEA's regulated operations as a result of the reduction in EAI's support needs.[20] The OAG stated that DEA had not justified the associated labor costs ($57,700[21]) for Finance, Billing, and Administrative support services now reassigned to the utility.[22] The OAG believes it is unreasonable for ratepayers to pay for these extra hours of labor that the Cooperative does not claim are needed to operate the regulated utility service, therefore recommends that the cost of this additional labor capacity be removed from the test year.

DEA

Annualizing Payroll Costs of Existing Positions' Part-Year Vacancies

DEA explained that the annualization compensation adjustment to its historical test year is for existing positions that are filled or in the process of being filled and reflects a full year of compensation and benefits at the Cooperative.[23] Fourteen of the seventeen positions were filled by the end of the test year.[24] DEA stated this adjustment recognizes the existing level of staffing that should be included in the test year and recovered through rates.

Dakota Electric stated it has reduced positions over the past ten years (from 210 to 196) and has reached the complement of employees necessary to provide the level of service expected by its members. Consequently, this is the normal level of staffing that should be funded through rates.

DEA stated that OAG's analysis comparing the impact of this adjustment to a 2010-2013 four year average payroll expense is based on outdated information;[25] and it ignores current total staffing and payroll costs which are the focus of a test year.[26] DEA also stated that the 2013 position vacancies were atypical, and represent unusual staffing events, such as two positions held open for employees stricken with cancer.

DEA quantified that disallowing this adjustment would have the net effect of removing from rate recovery the compensation and benefits of six existing DEA positions.[27] DEA argued that common sense dictates that the Cooperative should be allowed to charge rates so that it can pay existing employees their salaries and wages.

Incremental Position

The additional Powerline Design Technician position is to undertake the project design and documentation for use by construction, interface with new customers and developers and locate underground facilities. This position was filled in May 2014.[28]

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[20] Ex. 204 at 8 (Lee Surrebuttal)
[21] Tr. Evid. Hearing at 40 (Larson) (Dec. 18, 2014)
[22] Ex. 203 at 8 (Lee Direct)
[23] Ex. 126 at 36 (Larson Rebuttal) and Ex. 127 at 21 (Larson Surrebuttal)
[24] DEA Reply Brief at 1
[25] DEA Initial Brief at 4.
[26] DEA Reply Brief at 1
[27] DEA Initial Brief at 4, footnote 11.
[28] Ex. 126 at 13 (Larson Rebuttal)

Other – Support Hours Formerly Provided to Discontinued Operations

DEA stated that the finance and other administrative areas has a staff complement of 24 individuals and this staffing level has not changed as a result of the divestiture of the majority of DEA's subsidiaries. DEA stated that the Finance, Billing, and Administrative department staff hours[29] previously devoted to subsidiary activity are easily redirected to other regulated business activities during the course of a year. Of the employees that charged time to its formerly-held subsidiaries, only two were hourly employees and the remaining employees were salaried who often work more than 40-hours per week, including the CEO, Vice President of Finance and the Controller. DEA stated changes have been made to the responsibilities of various positions that previously charged time to subsidiaries and the OAG's recommendation is not warranted.[30]

ALJ

(ALJ Report, pp. 15-18; paragraphs 63-74)

[Annualizing Payroll Costs of Existing Positions' Part-Year Vacancies]

> 67. The Administrative Law Judge concludes that the underlying basis for the OAG's objection to DEA's annualization adjustment has merit. Historically, test year methodology "rests on the assumption that changes in [a] [c]ompany's financial status during the test year will be roughly symmetrical - some favoring [a] [c]ompany, others not .... Anomalies are likely to exist in and beyond the test year." Whether or not specific positions are fully filled during a test year does not warrant extra funding to cover the likelihood that all positions will be filled the following year. Each year brings turnover and circumstantial situations affecting a company's ability to keep positions filled. In the end, staffing changes will work themselves into the symmetry contemplated by the economics behind the test year methodology. Thus, the annualization adjustment requested by DEA in this case is not necessary.

[Incremental Position]

> 68. However, the OAG's proffered exclusion of $690,427 for the annualization adjustment is inconsistent with the amount requested by DEA. According to DEA witness Douglas Larson, DEA is seeking an annualization adjustment of $397,225 for 16 partially filled positions plus $68,210 for a new position added in 2014. The Administrative Law Judge recommends granting DEA's request for an increase of $68,210 to cover additional wages for the new added position in 2014, but disallowance of the increase of $397,225 to adjust for partial staffing in 2013, for a net disallowance of $329,015.

[Other – Support Hours Formerly Provided to Discontinued Operations]

> 74. The Administrative Law Judge concludes that the OAG's request for a downward adjustment to DEA's overall payroll expense based upon employee support service hours no longer being provided and billed to EAI lacks merit. There is no evidence that the 842 work hours previously provided and billed to EAI by DEA employees are not being fully utilized. On the contrary, DEA's testimony is that it is fully utilizing those employees' hours. More importantly, 21 of the 23 employees who billed EAI for work hours in 2010

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[29] The time amounted to an average of 25 hours per person, per year, or an equivalent of three days' work.

[30] DEA Initial Brief at 5

are salaried employees, including DEA's CEO, Vice President of Finance, and the Corporate Controller. The salaries of these employees have been included within DEA's operating expenses from 2010 through 2013. Therefore, a reduction to DEA's requested rate increase is not warranted.

Exceptions to the ALJ

DEA
(DEA Exceptions, pp. 1-4)

DEA took exception to ALJ Finding No. 67 stating that the theoretical evening out of changes in expenses inside and outside the test year referenced by the ALJ does not exist in this case. The unusual nature and duration of these vacancies explains why some positions were unfilled for part of the year, a departure from DEA's normal employment practices, thus making the test year atypical and unlikely to be repeated in the next year or years. (The wages and associated benefits for the two employees that died during 2013 alone account for $103,562 of the $690,427 total staffing annualizing adjustment.) Furthermore, DEA's adjustment is for both known and measurable changes to test year expenses and, therefore, should be allowed. Of the 16 existing positions, 14 were filled in Test Year 2013.

DEA also offered a technical clarification to ALJ Finding No. 68. The annualized wage adjustment for the existing positions ($397,225) does not include the cost of the incremental position ($68,210).[31] Together, these two DEA adjustments total $465,435 for payroll costs. In addition, tied to these payroll adjustments are corresponding benefit cost adjustments equivalent to 48.34 percent of payroll.[32] Therefore, a disallowance of the annualized wage adjustment for existing positions would be a reduction of $589,244 ($397,225 × 1.4834), not $329,015 as reflected in the ALJ's report. DEA incorporated this technical correction in its March 9, 2015 compliance filing schedules that reflect the ALJ's recommendations.

OAG
(OAG Exceptions, pp. 2-7)

The OAG took exception to the ALJ's Finding No. 68 that granted an upward adjustment for a newly added position and noted its technical errors.

The OAG excepts to the ALJ's recommendation to allow the incremental position adjustment arguing that the ALJ provides no basis for this decision. The OAG compared DEA's 2011 and 2013 staffing levels and expensed payroll amounts. The OAG stated that in 2011 with 196 employees Dakota's payroll expense was less than its 2013 base year with 195 employees (by more than $25,000). The OAG stated that DEA has not demonstrated that its 2013 base year costs are not representative.

In ALJ Finding No. 68, the OAG stated the ALJ incorrectly calculated the adjustment as being $329,015 and explained the technical error. The disallowance amount for annualizing wages of

[31] Ex. 102, Schedule DEA-1 at 5.
[32] Ex. 102, Schedule DEA-1 at 7.

existing positions should have been $589,244; the payroll costs of $397,225 plus the associated benefit costs. It appeared that the ALJ mistakenly overlooked Dakota's adjustment for associated benefit costs.

The OAG recommended the following modifications to the ALJ Findings No. 63, 64 and 68 as follows:

> 63. DEA requested recovery of increased costs in payroll expenses, including an annualization adjustment covering 16 employee positions vacant for a portion of the test year (2013), as well as the addition of one new employee position in 2014. According to DEA, it paid out $643,269 in actual wages for the 16 partially filled positions in 2013 instead of $1,040,494 in wages that would have been paid if the positions had all been filled for the entire year. DEA also added one new position (Powerline Design Technician) in 2014, which has an annual wage of $68,210. Based on the new additional position and total wages necessary to fully fund the 16 positions for an entire year, DEA requested an increased annualization adjustment of $465,435 and associated benefits. [*footnotes omitted*]
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> 64. ~~The OAG, however, valued DEA's annualization adjustment at $690,427 based on the wages claimed by DEA plus the OAG's calculation of the benefit expense for the 16 partially filled positions ($589,244) and one new added position ($101,183).~~ The OAG objected to DEA's annualization adjustment for two reasons. First, the OAG claimed DEA failed to show the increase is "a known and measurable change" because DEA's request covers positions "it hopes to fill or to remain filled, rather than positions ... it knows will be filled." The OAG claimed the additional "incremental position" for a new Powerline Design Technician "appears to inflate compensation expenses." Second, the OAG argued the requested increase cannot be reconciled with the general trend of DEA's payroll expense, which has been relatively flat for the past three years. Between 2010 and 2013, the OAG claimed the average change in DEA's annual payroll expense has been less than one percent as detailed in the table below: [*footnotes and table omitted*]
>
> 68. ~~However, t~~The OAG's proffered exclusion of $690,427 for the annualization adjustment should be adopted. DEA's 2013 base year payroll expense is highter than any of the previous three years, and the company has not demonstrated that an additional upward adjustment is reasonable. ~~is inconsistent with the amount requested by DEA. According to DEA witness Douglas Larson, DEA is seeking an annualization adjustment of $397,225 for 16 partially filled positions plus $68,210 for a new position added in 2014. The Administrative Law Judge recommends granting DEA's request for an increase of $68,210 to cover additional wages for the new added position in 2014, but disallowance of the increase of $397,225 to adjust for partial staffing in 2013, for a net disallowance of $329,015.~~

Staff Comments

In 2014, DEA expected a general wage increase of three percent for both union and non-union employees. The general wage increase adjustment was not disputed among the parties. DEA also expected to increase its workforce by one position, which it filled in May 2014.

The OAG's payroll analysis focused on the expensed payroll dollar amounts. However, the percentage of total payroll expensed (and capitalized) may change from year-to-year, depending on capital project activity; this affects the dollars reported as expensed. To address this, Staff has included the total payroll costs (Table 6). This provides a comprehensive overview of payroll costs and eliminates the payroll capitalization variable.

Table 6

Dakota Electric - Payroll Costs
Historic, Requested and Recommendations

				Total Payroll		Payroll Expensed			
Line #	Year		# Empl. d*	$	Δ in cost over prior Year	% Expensed	$ Expensed	Δ in expense over prior Year	Notes
1	2009	Actual	n/a	15,597,356		88.1%	13,743,302		a
2	2010	Actual	n/a	16,033,253	2.79%	87.8%	14,069,983	2.38%	a
3	2011	Actual	196	15,812,268	-1.38%	89.0%	14,068,038	-0.01%	a
4	2012	Actual	195	16,008,924	1.24%	87.6%	14,030,172	-0.27%	a
5	2013	Actual	195	16,244,288	1.47%	86.8%	14,093,131	0.45%	a
6	2014	DEA Request	196	*17,223,536*	6.03%	88.1%	15,176,774	7.69%	a,b,c
7	2014	ALJ Recom.		*16,772,741*	3.25%		14,779,549	4.87%	b
8	2014	OAG Recom.		*16,695,332*	2.78%		14,711,339	4.39%	b

Notes:
a - Ex. 102, Schedule DEA-1, p. 4
b - The 2014 *Total Payroll $ amounts* were derived by dividing the Payroll Expense $ by the 2014 expense factor (88.1%).
c - Requested 2014 Payroll Expense from Ex. 102, Schedule 7, p. 7
d - Ex. 203 at 7 for employee count

Payroll costs are either capitalized or expensed, however, the sum of capitalized and expensed amounts should equal total payroll costs incurred. For 2014, the Cooperative expressed its requested payroll recovery in expense terms, both in dollars ($15,176,774) and as a percentage expensed or a factor of 88.1 percent.[33] From this information, Staff imputed the requested test year total payroll cost for 2014 in the amount of $17,223,536 (shown in Line 6 in Table 6 above). The total payroll cost was not explicitly stated in the record, however, it appears the 2014 imputed total payroll cost request ($17,223,536) is about a six percent increase over its 2013 total payroll cost (of $16,244,288). Historically, total payroll costs have generally increased (1.24 to 2.79 percent), but not as sharply as the 6.03 percent change between 2013 and

[33] Ex. 102, Schedule DEA-1 at 4 and 7.

DEA's imputed 2014 request. From the (imputed) total payroll cost perspective, Staff agrees that DEA's test year adjustments, in totality, appear to result in an uncharacteristic cost increase.

The addition of one position with annual expensed wages of $68,210 would increase payroll costs by approximately 0.5 percent.[34] This incremental position, together with the stated three percent general wage increases, would approximately amount to a 3.5 percent increase in total payroll costs.

In Table 6, Line 7 and Line 8 provide the recommendations' of the ALJ and the OAG, respectively. Again, the total payroll cost was imputed by Staff using DEA's stated payroll expense factor (88.1%). When applying the ALJ's and the OAG's recommendation options, the total payroll cost change over 2013 payroll cost appear to be about a 3.25 percent and a 2.78 percent increase, respectively. The overall 3.25 percent result from the ALJ recommendation closely aligns with a general wage increase of three percent and the addition of one position. Similarly, a general wage increase of three percent appears to closely align with the overall 2.78 percent increase resulting from the OAG recommendation. Both alternatives' estimated outcome changes in total payroll costs are at the upper-end of DEA's experienced year-to-year cost changes.

DEA's position vacancies for both 2012 and 2013 were available in the record and Staff evaluated vacancy durations.[35] The cumulative duration of these vacancies (in total months for all open positions) for 2012 and 2013 were about 28.5 months and 52 months, respectively. Although 2013 cumulative duration exceeded 2012, this observation was inconclusive because, 1) the record lacked a monetized value of each year's vacancies to better evaluate the degree of change, if any, and 2) it was a limited sample of only two operating years. For example, a 12-month vacancy of positions that average pay of $5,500 per month would be equivalent to a 15-month vacancy of positions that average pay of $4,400 per month, therefore an increase in vacant position duration alone is inconclusive. Furthermore, with only two years' documentation in the record, it is not supportive that the vacancy duration in 2012 is more normal than the vacancy duration experienced in 2013. Vacancy duration may also be influenced by general economic conditions, such as unemployment levels.

Although it was not discussed in the record[36], Staff also notes that the increased duration of position vacancies could lead to increases in other operating costs that may be captured in the test year, such as death/disability benefit payments, unemployment insurance, contracted/temporary services, increased overtime paid to other employees, severance benefit payments, etc.

Regarding the technical errors in the ALJ Report, all parties are in agreement. DEA and the OAG discussed these corrections within their initial briefs and the Department of Commerce did so in a letter (filed on March 11, 2015).

[34] 0.5% = $68,210 / ($14,093,127 HTY expense + $228,590 capital-to-expense adjustment) Ex. 102, Schedule DEA-1 at 5 and 7.

[35] Ex. 203, Schedule SL-4 (Lee Direct)

[36] Evid. Tr. at 42 identified reasons for variance between two different 2013 payroll expense reported amounts was due to overtime pay, part-time pay, other pay and temporary help.

With respect to the OAG's recommended modifications to the ALJ report, Staff comments are:

- *ALJ Finding 63:* This modification provides clarity and can be adopted regardless of the Commission's decision on the disputed issues.
- *ALJ Finding 64:* This modification improves accuracy and can be adopted regardless of the Commission's decision on the disputed issues. The OAG adjustment value and its underlying calculation are from DEA-sourced information.
- *ALJ Finding 68:* The modification aligns with the adoption of the OAG's recommendations. However, if the Commission does not adopt the OAG's recommendation, a modification to the finding is still necessary for technical corrections; Staff provided a suggested modification in an alternate decision.

Decision Alternatives – Staffing Changes

(Note: The following decision alternatives correspond to 3:A-G in the Deliberation Outline, pp. 2-3.)

A. Approve Dakota Electric's requested test year payroll expense as reasonable and determine no adjustment is necessary; (DEA) **or**

B. Disallow the annualization wage adjustment for existing positions vacant for part of the year and disallow the salary costs for an additional position, which together result in a $465,435 reduction to the test year payroll expense and a corresponding $224,992 reduction to employee benefit costs. Modify ALJ Finding No. 68 as follows:

> 68. ~~However, t~~The OAG's proffered exclusion of $690,427 for the annualization adjustment should be adopted. DEA's 2013 base year payroll expense is higher than any of the previous three years, and the company has not demonstrated that an additional upward adjustment is reasonable. ~~is inconsistent with the amount requested by DEA. According to DEA witness Douglas Larson, DEA is seeking an annualization adjustment of $397,225 for 16 partially filled positions plus $68,210 for a new position added in 2014. The Administrative Law Judge recommends granting DEA's request for an increase of $68,210 to cover additional wages for the new added position in 2014, but disallowance of the increase of $397,225 to adjust for partial staffing in 2013, for a net disallowance of $329,015.~~ (OAG); **or**

C. Adopt the ALJ's finding that the increase to payroll expense for the additional position is reasonable, but disallows the adjustment made to reflect a full employee complement with no part-year vacancy of existing positions; (ALJ) **and**

Modify the ALJ Report Finding No. 68 for a technical correction of the calculated adjustment, to be a $397,225 reduction to the test year payroll expense and an additional $192,019 reduction to the corresponding test year employee benefit costs, consistent with the ALJ's described recommendation, to read as follows:

68. ~~However, the OAG's proffered exclusion of $690,427 for the annualization adjustment is inconsistent with the amount requested by DEA.~~ According to DEA witness Douglas Larson, DEA is seeking a~~n~~ payroll annualization adjustment of $397,225 for 16 partially filled positions plus $68,210 for a new position added in 2014. The Administrative Law Judge recommends granting DEA's request for an increase of $68,210 to cover additional wages for the new added position in 2014, but disallowance of the increase of $397,225 to adjust for partial staffing in 2013~~, for a net disallowance of $329,015~~. The Commission also disallows the corresponding test year increase of $192,019 for benefit costs associated with the denied partial staffing wage adjustment. (Staff)

Revisions to ALJ Findings

D. Modify ALJ report Finding No. 63 for clarity:

63. DEA requested recovery of increased costs in payroll expenses, including an annualization adjustment covering 16 employee positions vacant for a portion of the test year (2013), as well as the addition of one new employee position in 2014. According to DEA, it paid out $643,269 in actual wages for the 16 partially filled positions in 2013 instead of $1,040,494 in wages that would have been paid if the positions had all been filled for the entire year. DEA also added one new position (Powerline Design Technician) in 2014, which has an annual wage of $68,210. Based on the new additional position and total wages necessary to fully fund the 16 positions for an entire year, DEA requested an increased annualization adjustment of $465,435 and associated benefits. [*footnotes omitted*] (OAG)

E. Modify ALJ report Finding No. 64 for clarity by striking the first sentence in its entirety:

64. ~~The OAG, however, valued DEA's annualization adjustment at $690,427 based on the wages claimed by DEA plus the OAG's calculation of the benefit expense for the 16 partially filled positions ($589,244) and one new added position ($101,183).~~ The OAG objected to DEA's annualization adjustment for two reasons. First, the OAG claimed DEA failed to show the increase is "a known and measurable change" because DEA's request covers positions "it hopes to fill or to remain filled, rather than positions ... it knows will be filled." The OAG claimed the additional "incremental position" for a new Powerline Design Technician "appears to inflate compensation expenses." Second, the OAG argued the requested increase cannot be reconciled with the general trend of DEA's payroll expense, which has been relatively flat for the past three years. Between 2010 and 2013, the OAG claimed the average change in DEA's annual payroll expense has been less than one percent as detailed in the table below: [*footnotes and table omitted*] (OAG)

Support Hours Formerly Provided to Discontinued Operations

F. Adopt the ALJ's recommendation that no reduction to payroll expense is warranted for employee hours formerly billed to DEA's discontinued, non-regulated operations; (ALJ, DEA) **or**

G. Approve the OAG's recommended $57,700 test year reduction to remove the payroll expense and related benefit costs associated with the employee hours formerly expended to support DEA's discontinued, non-regulated operations. (OAG)

Record Citations:

Lee Direct, Ex. 203 at 4-8
Lee Surrebuttal, Ex. 205 at 3-9
Larson Rebuttal, Ex. 126 at 12-14
OAG Initial Brief at 4-9
OAG Reply Brief at 11-13
DEA Initial Brief at 4-5
DEA Reply Brief at 1-4
DEA Compliance Filing (March 9, 2015)
Department Letter (March 11, 2015)

Travel, Entertainment and Employee Expenses (T&E Expenses)

PUC Staff: Dorothy Morrissey

Statement of the Issues

Should the Commission allow recovery of travel costs expended by a director while running for election to the Cooperative Finance Corporation (CFC) Board of Directors? Should the Commission allow full cost recovery of airfare booked only few days before a conference? Should the Commission allow cost recovery of grocery refreshments provided to employees? Should the Commission allow cost recovery of a holiday lunch for Board members and key employees?

Introduction

In 2010, Minnesota Statute § 216B.16, subd. 17 was enacted to expand the filing requirements to support recovery of travel, entertainment and employee expenses (T&E expenses). The general statutory requirement for allowing any cost recovery by a utility is that costs must be reasonable and necessary for the provision of utility service. In addition, in Otter Tail Power's 2010 rate case, the Commission clarified the filing requirements that this information be provided in a searchable, sortable format and should clearly describe the purpose of the expense.[37]

[37] FINDINGS OF FACT, CONCLUSIONS, AND ORDER In the Matter of the Application of Otter Tail Power

For recovery in this case, DEA provided detailed travel and meal expenditures of approximately $190,336, in addition to other expenses for Board of Directors ($329,832), dues and memberships ($286,456), and events ($3,911), collectively exceeding $800,000.[38]

The OAG examined the Travel, Entertainment and Employee expenses requested for recovery and identified several costs it believes are unreasonable and not necessary for the provision of utility service. Of the several issues that the OAG objected to, a retirement dinner at a cost of $3,141 has been resolved because DEA agreed to remove it from its test year stating that this cost was not expected to recur.

The unresolved issues total $7,169 and consist of:

- Travel reimbursement for a DEA director running for election to the Cooperative Finance Corporation (CFC) Board of Directors ($2,066);
- One-half of the cost for airfare booked a few days before the trip ($672);
- Grocery and food expenses for various DEA functions ($3,909); and
- DEA Board holiday lunch ($522)

OAG

The OAG stated that the T&E expenses it has identified are unnecessary, imprudent, and do not provide direct benefits to ratepayers.[39] The OAG stated that DEA has not demonstrated that any of the expenses objected to by the OAG are necessary or that they directly benefit ratepayers. Minnesota Statutes section 216B.17 does not include a *de minimis* exception.

The OAG objected to the inclusion of ($2,066) travel costs incurred by a board member to attend regional cooperative meetings while running for election to the CFC board of directors because the expenses were not necessary or reasonable for the provision of DEA's utility service.[40] Rather, the OAG believed the purpose of this expense was this board member's personal and separate employment objectives, rather than the provision of DEA's utility service.[41]

The OAG also objected to the inclusion of the full cost of airfare ($1,344) booked on short notice for a board member to attend a legislative rally in Washington, DC. The high airfare was due to a delay in booking, thus the OAG recommended one-half cost of the ticket ($672) be excluded from recovery.[42] The OAG's recommendation is based on information in the test-year record and does not rely on hypothetical or speculative circumstances outside of the test year.[43]

The OAG objected to $3,909 in grocery and food expenses served at various meetings, functions, events, wellness programs, and to supply field employees with water during hot summer

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Company for Authority to Increase Rates for Electric Utility Service in Minnesota, Docket No. E017/GR-10-239 at 34 – 36 and ordering paragraph 12 (April 25, 2011).

[38] Ex. 203 at 9, 11 (Lee Direct)

[39] OAG Initial Brief at 11

[40] Ex. 203 at 12 (Lee Direct)

[41] Ex. 205 at 10 (Lee Surrebuttal)

[42] Ex. 203 at 13 and Schedule SL-10 (Lee Direct)

[43] Ex. 205 at 10 (Lee Surrebuttal)

weather. With the exception of water for field employees, the OAG stated these expenses are not necessary or reasonable for the provision of DEA's utility service. However, due to lack of connecting detail, the OAG was not able to determine water costs for this purpose, thus recommended the full amount be excluded from recovery.

The OAG objected to the inclusion of a $522 holiday lunch for Board of Directors and select staff members because the expense was not necessary for the provision of utility service and should not be recovered from ratepayers.[44]

The OAG also expressed concern about the reasonableness of the expense "Board of Director Electronic Reimbursements" which totaled $17,841. DEA board members are allowed reimbursements of up to $150 per month to cover internet connection fees, cell phones, and data plans to facilitate communications. The OAG believed the DEA board members would have standard communication methods available regardless of their membership on DEA's Board of Director, and these services could arguably be used for both personal and business purposes. However, the OAG did not recommend exclusion of the expense.

The OAG argued that simply because a particular expense is typical for a business does not mean that it may be recovered from ratepayers. For example, the Commission has held that membership dues for business organizations are recoverable "only to the extent that the activities they support directly benefit ratepayers," and has excluded membership dues for organization such as the Chamber of Commerce.[45] This does not mean that utilities cannot incur these expenses, but rather that they cannot seek recovery from ratepayers.

DEA

DEA explained that CFC is a substantial lender to Dakota Electric and the cost of debt is important to its operations. In regards to regional meeting travel costs of a board member, DEA argued that potential participation on the board of directors of a major lender is related to its regulated service, has significant value and should be included as an expense in the test year. No evidence indicated the expense was related to the director's personal employment agenda. DEA suggested that in any given year this cost could be incurred by directors traveling to regional meetings for power supply matters or CFC conferences.

Regarding the airfare cost, DEA explained when it determined that it did not have anyone attending this conference the arrangements were made only days before the event. While this contributed to a higher airfare in this case, in another year this same expense could have been incurred for two people to attend the conference. DEA believed the expense was justified in this instance due to the importance of attending the conference.

DEA stated the disputed $3,909 food expense was incurred at legitimate Association functions/meetings such as employee wellness events in an effort to reduce medical claims, and

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[44] Ex. 205 at 13 (Lee Surrebuttal)

[45] In the Matter of the Application of Interstate Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota, Docket E-001/GR-91-605, 1991 WL 634712, at *3 (Oct. 11, 1991) (emphasis added). See also Minn. Stat. § 216B.17(a)(6) (2013).

working lunches and other meetings to keep employees refreshed, alert, and productive.[46] DEA specifically quantified that $528 was spent for beverages supplied to field workers[47] and $608 was expended for wellness program events.[48]

With respect to the $522 holiday lunch, DEA stated the December lunch was no different from other monthly lunch breaks that the Board of Directors take during regular meetings the other eleven months of the year. DEA believed this is a legitimate cost of doing the administrative business to provide electric service.[49]

Regarding "Board Electronic Reimbursements", DEA stated that such reimbursements support a consistent/adequate communication base to facilitate electronic communication to accomplish board functions and communicate with senior management regarding cooperative operations. In recent years, the board has moved to conducting business through electronic means only.[50]

DEA believes the issue of whether these expenses were prudently incurred in the end comes down to the exercise of reasonable business judgement in light of the purposes for which they were incurred. DEA believes these expenses were reasonably incurred and were related to the provision of electric service. If these costs are not recovered from ratepayers, there is no separate set of owners or investors from which they can be recovered.

ALJ

(ALJ Report, pp. 11-15; paragraphs 56-62)

> 61. The Administrative Law Judge concludes that DEA has provided sufficient evidence, including itemized information, to show the business expenses objected to by the OAG were incurred as legitimate costs of doing the administrative business necessary for DEA to provide electric service. Specifically:
>
> a) The Administrative Law Judge agrees that DEA's efforts to foster a closer relationship between its Board of Directors and the board of a major lender such as CFC is related to DEA's provision of electric service, and has the potential to benefit DEA's members. Thus, the $2,066 expense for travel and meals incurred when DEA's Director attended regional meetings of electric cooperatives in Minnesota and the Dakotas while he was running for election to the CFC Board of Directors is legitimate and recoverable.
>
> b) The Administrative Law Judge concludes that DEA had a reasonable basis to purchase a premium airfare for its Board member to attend an important conference related to the provision of electric service. According to DEA, the premium airfare was purchased "[w]hen we determined that DEA did not have anyone attending this conference[,] the arrangements were made to have a DEA employee attend the event." Notably, the OAG did not dispute that the

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46 DEA Initial Brief at 3
47 Evid. Tr. at 41
48 Evid. Tr. at 122.
49 DEA Initial Brief at 3-4
50 Ex. 126 at 17 (Larson Rebuttal)

DEA representative's attendance at the conference was reasonable and necessary for the provision of electric service. Therefore, the $672 expense for airfare purchased a few days prior to the conference in Washington, D.C. is legitimate and recoverable. [*footnotes omitted*]

c) DEA withdrew the one non-business related food expense from its initial request: the social gathering in honor of its attorney's retirement. Otherwise, the OAG does not object to the basis for all of the other food expenses included as business expenses in DEA's request for recovery. With regard to the $680 portion of groceries used for DEA's wellness program, the OAG conceded that participation in a wellness program leading to a reduction in health insurance premiums is related to DEA's provision of electric service. Therefore, the $3,909 expense for food and drink items from Family Fresh Market, Sam's Club, and Farmington Bakery is reasonable and recoverable. [*footnotes omitted*]

d) The Administrative Law Judge concludes that DEA's expense for a "holiday luncheon" was reasonable because the $522 was spent on lunch for 29 people during the regular December DEA Board of Directors meeting. Therefore, the Administrative Law Judge recommends that the $522 expense for DEA's December Board luncheon be recoverable. [*footnotes omitted*]

62. Based on the foregoing reasoning, the Administrative Law Judge recommends DEA's request for business expenses stemming from travel and meals for its employees, as well as food and event expenses for its Board of Directors, be included in the test year for rate recovery, minus the $3,141 expense for the retirement party.

Exceptions to the ALJ

OAG
(OAG Exceptions, pp. 7-8)

"While each of the Travel and Entertainment expenses identified by the OAG came from the categories highlighted in Minnesota law for careful scrutiny, the ALJ appears to have applied a relatively lenient standard in awarding recovery of these costs. … The ALJ did not conclude that these costs provided any direct benefit to ratepayers. Instead, the ALJ justified her recommendation by pointing to tangential and speculative benefits, or to benefits for Dakota's employees, rather than to ratepayers." Accordingly, the OAG took exception to Findings 61 and 62 (reproduced above) and recommended they be replaced with the following:

61. <u>DEA has not demonstrated a direct benefit for the Travel and Entertainment expenses identified and challenged by the OAG. Rather, DEA has sought recovery of these expenses by pointing to tangential and speculative benefits. This is not sufficient to warrant recovery, particularly for costs that have been identified in statute for careful scrutiny. Accordingly, it is not reasonable for DEA to receive recovery of $2,066 in expenses for its board member to run for the board of the CFC board, of $672 in excess</u>

airfare costs for a late scheduled trip, of $3,909 for groceries to serve at company functions, or $522 for food served at a board meeting.

Staff Comments

The issue before the Commission is the principle or the nature of these T&E disputed costs, rather than their rate impact.

It is important to note that the detailed travel, entertainment and employee expense information supplied in rate filings by utilities provide the basis for their test year request, therefore it is evaluated as representative of the types of expenses being recovered. A few of the Cooperative's arguments suggest that it is plausible the cost level of disputed item may occur in other years, with different supporting circumstances. However that argument discounts or distracts from the facts or relevancy of the support information provided in the filing.

Travel cost for a director's attendance at regional meetings may be a legitimate cost in any year, however, for the identified itemized T&E costs, the purpose behind this attendance indicated the director was running for election to the CFC board, the organization that provides financial services to cooperatives. What is under scrutiny is the business purpose of this test year cost, not necessarily whether the same amount of travel costs could be spent in another year for less controversial purposes. Elected directors to the CFC Board serve three-year terms.[51] If the Commission determines this expense was incurred to serve DEA's ratepayers or provide ratepayer benefit, it may also consider whether the full amount should be reflected in the test year, or perhaps only one-third of its cost should be in test year to align recovery with the duration of the position sought.

The high cost for airfare resulting from delayed booking has raised a prudency and/or management issue. The reasonableness of the purpose for travel is not disputed. It was not indicated that the event arose suddenly, which could lead to last-minute planning. Rather, it appears the increased cost could have been avoided with advanced planning. Here again, the Cooperative suggested this cost level is plausible if DEA sent two persons in another year. What is relevant is the test year recovery level for T&E that is based on the data supplied in the filing. The Commission is to determine whether the cost was reasonable and prudent under the circumstances in which it was incurred.

Finally, DEA pointed out the uniqueness of a cooperative, stating that if these costs are not recovered from ratepayers, there is not a separate set of owners or investors from which they can be recovered. Although this statement is true, years ago DEA's members opted to have additional oversight of its utility operations by subjecting itself to regulation. Commission rate setting decisions, including which expenses are recoverable, can provide future benefits and influence DEA's future expenditures or procedures.

[51] https://www.nrucfc.coop/content/cfc/about_cfc/leadership/board_of_directors/learn-more-about-the-board.html (accessed April 6, 2015)

Decision Alternatives – Travel, Entertainment and Employee Expenses

(Note: The following decision alternatives correspond to 4:A-J in the Deliberation Outline, pp. 4-5.)

Travel Cost for Election Campaign

A. Allow test year recovery of $2,066 for director travel incurred while campaigning for election to Cooperative Finance Corporation (CFC) Board of Directors; (DEA, ALJ) **or**

B. Disallow recovery of $2,066 for director travel incurred while campaigning for election to Cooperative Finance Corporation (CFC) Board of Directors; (OAG) **or**

C. Reduce test year recovery level for director travel incurred while campaigning for election to Cooperative Finance Corporation (CFC) Board of Directors to $687, or one-third of requested cost level, to normalize cost recovery level to the duration of CFC board member term (three-years). (Staff)

Airfare Cost

D. Permit full recovery of the $1,344 airfare cost for DEA Board member's trip to attend a conference in Washington, DC; (DEA, ALJ) **or**

E. Limit recovery to one-half of airfare cost (or $672) for DEA Board member's trip to attend a conference in Washington, DC. (OAG)

Groceries

F. Allow test year recovery of $3,909 expended on groceries served to DEA employees and board members at various functions; (DEA, ALJ) **or**

G. Disallow test year recovery of $3,909 expended on groceries served to DEA employees and board members at various functions. (OAG)

Holiday Lunch

H. Allow test year recovery of $522 expended on holiday lunch for DEA's Board members and key employees; (DEA, ALJ) **or**

I. Disallow test year recovery of $522 expended on holiday lunch for DEA's Board members and key employees. (OAG)

Modification to ALJ Report

J. Modify ALJ Findings 61 and 62 by striking both findings in their entirety and replacing Finding 61 with the following:

61. DEA has not demonstrated a direct benefit for the Travel and Entertainment expenses identified and challenged by the OAG. Rather, DEA has sought recovery of these expenses by pointing to tangential and speculative benefits. This is not sufficient to warrant recovery, particularly for costs that have been identified in statute for careful scrutiny. Accordingly, it is not reasonable for DEA to receive recovery of $2,066 in expenses for its board member to run for the board of the CFC board, of $672 in excess airfare costs for a late scheduled trip, of $3,909 for groceries to serve at company functions, or $522 for food served at a board meeting. (OAG)

Record Citations:

Lee Direct, Ex. 203 at 9-14
Lee Surrebuttal, Ex. 205 at 9-13
Larson Rebuttal, Ex. 126 at 15-17
Larson Surrebuttal, Ex. 127 at 21-22
OAG Initial Brief at 9-12
OAG Reply Brief at 13
DEA Initial Brief at 2-4
DEA Reply Brief at 4-5

Other Non-Operating Income - Non-regulated Subsidiary Net Income (Resolved)

PUC Staff: Dorothy Morrissey

Statement of the Issues

Should income from a non-regulated subsidiary be excluded when determining the regulated utility's revenue requirements? What amount of Other Non-Operating Income should the Cooperative include in its final compliance schedules?

Introduction

Other non-operating income generally is income from passive activity, such as interest from investments or other holdings. Income from such sources can reduce a utility's operating revenue requirements.

The issue was settled between the Department and DEA.[52]

Department

Within its Other Non-Operating Income amounts, in addition to investment interest income, Dakota Electric included non-regulated subsidiary income of $272,889. The Department raised

[52] Ex. 128 at 5 (Settlement Agreement)

concerns with DEA's inclusion of its wholly-owned for-profit subsidiary's income in "Other Non-Operating Income".[53]

The Department stated that rate-regulated utilities normally calculate their required net operating income and resulting test-year revenue deficiency on a stand-alone basis. The Department explained that stand-alone basis means that costs and revenues are allocated appropriately between the utility and non-utility businesses, so that only the utility's financial information is used to set rates. This approach prevents a utility's non-regulated subsidiary activities from impacting the rates charged to ratepayers.

In response to the OAG's rebuttal testimony, the Department emphasized that regulated electric rates should be based only on the revenues and expenses necessary to provide safe and reliable electric service. Regulated electric rates should not be based on revenues and expenses (net income) associated with a non-regulated subsidiary.[54] With respect to DEA's overall equity, lenders commonly take into consideration a utility's regulated and non-regulated operations (including wholly-owned for-profit subsidiaries) when determining the credit worthiness or financing rates for a utility. This consideration occurs regardless of whether a utility is a publicly-held corporation, a privately-held corporation, or a cooperative.[55]

The Department noted that in this case, although inclusion of the subsidiary's net income would decrease the overall revenue deficiency and results in lower rates for ratepayers, the opposite would have occurred if DEA had selected 2012 as the test year.[56]

The subsidiary net income is recognized on Dakota Electric's overall books, but the Cooperative does not receive this income unless it is transferred as a dividend from the subsidiary. Dakota Electric does not expect to see any subsidiary dividends during the expected "revenue life" of this rate case.

Consistent with the stand-alone concept which prevents ratepayers from benefitting or subsidizing a utility's non-regulated subsidiary activities, the Department recommended that the $272,889 in subsidiary net income be removed from DEA's required net operating income and test-year revenue deficiency calculations. In its letter dated March 11, 2015, the Department corrected a typo found in the result of its recommendation. Reducing DEA's non-operating income of $399,147 by $272,889 would result in "Other Non-Operating Income" inclusion of $1**2**6,258 [originally stated as $116,258[57]] when determining the revenue requirement. The Department requested DEA to incorporate this correction in its compliance filing following the Commission's final determination.

OAG

The OAG had some concerns with the inclusion or exclusion of non-regulated subsidiary net income in the determination of rates. Factors that the OAG raised were, 1) recognition that DEA

[53] Ex. 308 at 7 (Johnson Direct)
[54] Ex. 310 at 4-5 (Johnson Surrebuttal)
[55] Ex. 310 at 5 (Johnson Surrebuttal)
[56] Ex. 308 at 8 (Johnson Direct)
[57] Ex. 308 at 9 (Johnson Direct)

is a cooperative, where its members are its ratepayers; 2) income needed to meet loan covenants considers both DEA's regulated and non-regulated operating results; 3) non-regulated operating results typically are not included in the determination of a regulated utility's revenue requirement; and, 4) there has been inconsistent treatment of subsidiary net income in DEA's previous two rates cases.

The OAG noted several arguments could be made in support of excluding and in support of including non-regulated subsidiary activity in the revenue requirement calculation.

"Support exclusion": The OAG agreed with the Department that a utility should track their regulated and non-regulated activity separately so that revenues and costs are allocated appropriately. "Support inclusion": But unlike investor-owned utilities, because DEA is a cooperative, the OAG was less concerned that ratepayers might be unfairly benefitting or subsidizing the utility's non-regulated subsidiary activities.

"Support exclusion": The OAG stated including subsidiary income in the calculation of the revenue requirement in the current petition would be inconsistent with how subsidiary income was treated in the previous rate cases in 2003[58] and 2009[59]. "Support inclusion": The OAG believed earnings from non-regulated subsidiary impacted the Cooperative's patronage capital or margins. The OAG believed any subsidiary net loss could be assigned to members on a patronage basis and would translate as a lower level of DEA patronage capital for the ratepayers/member owners. Lender covenants may restrict retirement of DEA patronage capital.[60]

In the evidentiary hearings, the OAG indicated DEA's surrebuttal testimony (described below) resolved the OAG's concerns.[61] However, the OAG did not make a recommendation, rather stated it neither agreed nor disagreed with the Department's recommendation to exclude the subsidiary net income.[62]

DEA

In surrebuttal, DEA responded to the OAG's rebuttal comments. DEA explained and clarified that non-regulated subsidiary net income does not impact the Cooperative's operating margins and is not included in Dakota Electric's patronage capital allocations. Operating margin is calculated as the difference between revenue and the expenses from providing electric service and does not include non-regulated subsidiary net income. [63] Patronage capital allocations are governed by the Cooperative's Bylaws and is tied with *delivery of electric energy*. Dakota Electric's Bylaws do not require non-regulated subsidiary net income to be allocated to members

[58] Subsidiary income was excluded in 2003. TESTIMONY OF D.R. LARSON, In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Utility Service in Minnesota, Docket No. GR-03-261 at 8.
[59] A portion of subsidiary income was excluded in 2009. TESTIMONY OF D.R. LARSON, In the Matter of the Application of Dakota Electric Association for Authority to Increase Rates for Electric Utility Service in Minnesota, Docket No. GR-09-175 at 8.
[60] Ex. 204 at lns 100-103, lns. 130-133 (Lee Rebuttal)
[61] Evid. Tr. at 113-114 (Lee)
[62] Evid. Tr. at 113 (Lee)
[63] Ex. 127 at 6-7 (Larson Surrebuttal)

of the Cooperative. Furthermore, DEA stated that a review of the Cooperative's primary financial metric used by its lenders, Modified Debt Service Coverage (MDSC), shows that non-regulated subsidiary net income is not included in the MDSC calculation.

Dakota Electric agreed with the Department's recommendation to exclude non-regulated subsidiary net income from the determination of revenue requirement.

ALJ

This is a resolved issue discussed in Findings 24 and 25, pages 5-6.

Staff Comments

There is possibility in this case that the cumulative adjustments may calculate to a revenue requirement in excess of DEA's request. Therefore, the discussion of Other Income - Non-regulated subsidiary net income is included in the briefing paper to ensure a clear Commission decision on this issue occurs and to ensure the resulting revenue deficiency remains within the confines of statute. As stated by the Department, the final revenue deficiency determined by the Commission must be consistent with Minnesota Statute §216B.16, subd. 5, which does not allow the revenue requirement to exceed the overall level of rates requested by the public utility.

The OAG discussed the issue but took no position on the adjustment. However, because the OAG recommended other adjustments, the record should be made clear whether any OAG adjustments favored by the Commission are subject to netting against this particular issue's quantified adjustment. Therefore, Staff recommends that the Commission take action to either adopt or deny the Other Non-Operating Income adjustment recommended by the Department.

Decision Alternative - Other Non-Operating Income

(Note: The following decision alternative corresponds to 5:A in the Deliberation Outline, p. 5.)

A. Adopt the resolution between DEA and the Department, that DEA's non-regulated subsidiary income should be excluded from Other Non-Operating Income when determining the revenue requirement; (DOC, DEA, ALJ resolved) **and**

   Clarify that the amount of Other Non-Operating Income included when determining revenue requirement should be $126,258 ($399,147 - $272,889). (DOC letter March 11, 2015)

Record Citations:

Johnson Direct, Ex. 308 at 6-9
Johnson Surrebuttal, Ex. 310 at 1-10
Lee Rebuttal, Ex. 204 at 1-8 (entirety)
Larson Surrebuttal, Ex. 127 at 4-10
DOC Initial Brief at 22-24
Evidentiary Tr. at 112-114 (Lee)
DOC Letter filed March 11, 2015

Purchased Power – Revenue and Expense (Resolved)

PUC Staff: Dorothy Morrissey

Statement of the Issue

Should the Cooperative be required to provide purchased power revenue and expense workpapers in the initial filing of its next rate case?

ALJ

This is a resolved issue discussed in ALJ Findings 53-55, page 11.

Staff Comments

As mentioned in the introduction, Dakota Electric is a distribution only electric service utility and purchases its wholesale power and related transmission services from Great River Energy (GRE). Dakota does not mark-up purchase power costs, rather bills its members energy charge rates designed to match the projected purchased power costs. In addition, Dakota Electric utilizes a Resource and Tax Adjustment, filed annually (and reviewed mid-year) to incorporate changes in purchased power costs (and other factors) and to true-up these costs' over- or under-recoveries.

In Dakota's general rate case filing, to determine revenue deficiency, the purchased power revenue and the purchased power expense amounts stated in financial schedules should be equal in order to accurately determine the revenue shortfall associated with the electric distribution service.

In response to the Commission's request (Order issued August 29, 2015), the Department obtained more detailed schedules from DEA and reviewed this matter. There were some discrepancies between the reported purchased power revenue and the purchased power expense that Dakota attributed to prior year carry-over/true-ups and rounding;[64] consequently, in this case the discrepancy was in favor of ratepayers. The Department concluded the issue as resolved.[65] However, Staff recommends that in Dakota Electric's next rate case filing that the Cooperative evaluates and makes the necessary pro forma adjustments to ensure the pro forma test year financial schedules reflect equal amounts for purchased power revenues and expense expected to be incurred for test year service rendered, removing revenue (or returns) attributed to prior years' carry-over/true-up. Staff recommends that Dakota Electric be required to include in its initial filing the supporting workpapers to assist the Commission and the parties in their evaluation of the pro-forma test-year purchased power revenues and purchased power expense amounts, and the calculated rate increase requests.

[64] Ex. 127 at 19 (Larson Surrebuttal)
[65] Ex. 128 at 14-15 (Settlement Agreement)

Decision Alternative – Purchased Power Revenue and Expense
(Note: The following decision alternative corresponds to 6:A in the Deliberation Outline, p. 5.)

A. Require Dakota Electric Association, in the initial filing of its next rate case, to include workpapers for both the purchased power revenue and purchased power expense amounts included in the pro forma test year financial schedule. (Staff)

Record Citations

Zajicek Direct, Ex. 306 at 7-8
Zajicek Surrebuttal, Ex. 307 at 1-3
Larson Surrebuttal, Ex. 127 at 18-20
DOC Initial Brief at 28-29

Depreciation and Reserve Depreciation (Resolved)

PUC Staff: Dorothy Morrissey

One of the known and measureable adjustments DEA proposed was an increase in depreciation expense by the amount of $78,749. However, through discovery, it was determined that DEA overlooked making a corresponding adjustment to its depreciation reserve.[66] Rate base would be overstated without this corresponding adjustment, therefore, both the Department[67] and the OAG[68] recommended DEA increase depreciation reserve by $78,749. DEA agreed to this recommendation, and effectively reduced its rate base by this amount.[69]

The issue is settled between the Department and DEA.[70]

ALJ

This is a resolved issue discussed in Finding 26, page 6.

Record Citations

Johnson Direct, Ex. 308 at 9
Lee Direct, Ex. 203 at 8
Larson Rebuttal, Ex. 126 at 4-5
Evid. Tr. at 116 (Lee)
DOC Initial Brief at 24-25

[66] Ex. 308, Schedule MAJ-8 (Johnson Direct)
[67] Ex. 308 at 9 (Johnson Direct)
[68] Ex. 203 at 8 (Lee Direct) and Evid. Tr. at 116 (Lee)
[69] Ex. 126 at 4-5 (Larson Rebuttal)
[70] Ex. 128 at 5-6 (Settlement Agreement)

Percentage of Payroll Expensed (Resolved)

PUC Staff: Dorothy Morrissey

DEA proposed to use a normalized percentage of payroll to be expensed and capitalized and calculated a normalized factor to be the average of its 2009 – 2012 experience. By this approach, DEA determined its normalized payroll expense factor to be 88.1 percent. In its test year, the expensed payroll was 86.8 percent of total payroll, therefore an adjustment to the historic test year payroll expense dollars was needed to reflect a normalized expense level of 88.1 percent. DEA proposed an increase of $228,590 to payroll expense to achieve the 88.1 percent expense ratio. However, through discovery, it was determined that DEA overlooked making a corresponding adjustment to its rate base for the reduction in the amount of payroll being capitalized.[71] Rate base would be overstated without this corresponding adjustment, therefore, the Department recommended DEA reduce its rate base by $228,590.[72] DEA agreed to this recommendation, and effectively reduced its rate base by this amount.[73]

The issue is settled between the Department and DEA.[74]

ALJ

This is a resolved issue discussed in Finding 27, page 6.

Record Citations

Johnson Direct, Ex. 308 at 9-10
Larson Rebuttal, Ex. 126 at 4-5
DOC Initial Brief at 25-26

Cash Working Capital (Resolved)

PUC Staff: Dorothy Morrissey

Cash Working Capital (CWC) is the amount of liquidity necessary to operate a utility during the interim between the rendition of service, including the payment of related expenses and the receipt of revenue in payment of services rendered. DEA applied lead/lag study factors to its test-year cash operating expenses and determined a cash working capital requirement of $6,987,282, which was added to its test-year rate base.[75] In its review, the Department recommended that DEA remove the test-year interest expense dollars from its CWC lead/lag study because interest expense (or cost of debt) is included in the overall rate of return and should not be in CWC calculations.[76] The Department quantified the impact of its

[71] Ex. 308, Schedule MAJ-9 (Johnson Direct)
[72] Ex. 308 at 10 (Johnson Direct)
[73] Ex. 126 at 4-5 (Larson Rebuttal)
[74] Ex. 128 at 6 (Settlement Agreement)
[75] Ex. 110, Schedule DEA-9 at 1 and Ex. 103, Schedule DEA-2 at 2
[76] Ex. 308 at 11 (Johnson Direct)

recommendation to be a rate base reduction of $125,290.[77] DEA agreed to this recommendation and effectively removed interest expense from its CWC lead/lag study.[78] Because the iteration of CWC is affected by other adjustments under review, the precise CWC will be calculated by DEA upon the Commission's final determination of all revenue and expense issues.

The Department also pointed out that an interplay between rate base and the development of the rate of return exists that is unique to a cooperative, unlike investor-owned utilities. Therefore, should the rate base amount change, a recalculation of the rate of return on rate base becomes necessary.[79]

The issue is settled between the Department and DEA.[80]

ALJ

This is a resolved issue discussed in Finding 28, page 6.

Record Citations

Johnson Direct, Ex. 308 at 10-12
Johnson Surrebuttal, Ex. 310 at 10-11
Larson Rebuttal, Ex. 126 at 4-5
DOC Initial Brief at 26-27

[77] Ex. 308, Schedule MAJ-4 (Johnson Direct)
[78] Ex. 126 at 4-5 (Larson Rebuttal)
[79] Ex. 208 at 12 (Johnson Direct) and Ex. 310 at 11 (Johnson Surrebuttal)
[80] Ex. 128 at 6-7 (Settlement Agreement)

Cost of Capital (Resolved)

PUC Staff: Ganesh Krishnan

Statement of the Issue

Should the Commission adopt the ALJ's finding that the amended settlement regarding capital structure, cost of debt, return on equity, and overall rate of return on rate base between the Department and DEA is reasonable?

Introduction

DEA and the Department agreed on a capital structure, a cost of debt, and a return on equity that resulted in an overall rate of return of 6.47 percent. The OAG did not object. The ALJ recommended approval.

Background

Capital Structure in General for an Electric Cooperative
DEA, like any other business firm, needs capital to meet operating expenses and provide for future expansion of business. Capital comes in two forms: debt and equity.

Debt
Debt capital is borrowed money, on a short- or long-term basis, by the cooperative which must be paid back on time.

Equity
Equity capital for a cooperative is provided by the cooperative's own 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.[81]

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 these dividends serves as an inducement to investors and is a critical component of the cost of common equity capital.[82]

However, DEA is not an IOU, it is a cooperative and its ratepayers are also its investors. Unlike the case of an IOU, the required rate of return on DEA's equity is not determined by the opportunity cost of investing capital somewhere else; rather, it is determined by the need to finance the growth of DEA's rate base and maintain a sound capital structure.[83]

[81] Ex. 300, Dr. Amit Direct at 4.
[82] Ex. 300, Dr. Amit Direct at 4.
[83] Ex. 300, Dr. Amit Direct at 6.

The equity portion of the capitalization of DEA is collected from the utility's customers through the rates.[84] When revenues exceed expenses, each customer/member of the cooperative is assigned a portion of the margin (that is, the portion of the amount by which revenues exceed expenses) on the basis of 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.

DEA does not pay traditional dividends 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.

Adjustments to Weighted (or Overall) Cost of Capital

The Commission has observed that the rate of return (ROR), as applied to cooperatives, permits the development of sufficient margins to cover the cost of debt and equity capital.[85] DEA notes[86] that the ROR method is intended to ensure that DEA's earnings are sufficient to cover the cost of debt (interest) and generate a fair return on the investment (equity) for the owners. Because DEA is a cooperative, the "return on equity" is related to the retirement, or rotation, of patronage capital.

In the case of 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 points out,[87] 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.

However, in the case of DEA, there is a divergence between the test-year capitalization and rate base. As the Department points out,[88] this is sometimes due to regulatory treatment of various assets that may or may not be included in the rate base. Besides, unlike an IOU, DEA is required to pay patronage capital to its members, making such payments to equity holders similar to the interest payments to bond holders. Also, as the Department notes,[89] because DEA purchases equity capital only from its members who are required to invest in DEA in order to receive electric service, and because DEA does not pay dividends out of its earnings, DEA's required rate of return on equity would be lower than its true cost of equity capital.

The Department noted[90] that because the overall rate of return is applied to the rate base to produce the appropriate level of net income, the overall rate of return on total capital must be adjusted to allow DEA to earn the same amount on its rate base as it would earn on its total capitalization. Further, in order to allow both bondholders and equity holders (DEA'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.[91]

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[84] Ex. 300, Dr. Amit Direct at 5.
[85] Findings of Fact, Conclusions of Law and Order in DEA's rate case (Docket No. E111/GR-09-175), May 24, 2010, p. 10.
[86] Ex. 101, Larson Direct at 13.
[87] Ex. 300, Dr. Amit Direct at 17.
[88] Ibid.
[89] Ex. 300, Dr. Amit Direct at 17.
[90] Ex. 300, Dr. Amit Direct at 18.
[91] Department Initial Post-Hearing Brief at 20.

This adjustment to DEA's weighted (or overall) cost of capital requires that the rate of return on rate base (ROR) be calculated as follows:

ROR = Weighted Cost of Capital * (Total Capitalization/Approved Rate Base).

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

DEA's Initial Proposal

DEA notes that the rate of return must result in sufficient margins to enable DEA to meet its interest expense obligations, rotate patronage capital and help maintain/achieve its desired equity position, and meet the financial covenants of its lenders.[92] DEA has determined that it needs to return $2.5 million per year as capital credits.[93]

DEA proposed the following capital structure and rates of return (Source: Larson Direct at 15 and DEA-2, p. 8):

Table 7

Type of Capital	Amount	Proportion	Cost	Weighted Cost
Equity	$136,837,360	53.285%	4.49%	2.39%
Debt	$92,752,617	46.715%	5.31%	2.48%
Total Capital/ Weighted Cost of Capital	$229,589,977	100.000%		4.87%
Rate Base & Return on Rate Base	$171,613,635		Rate Base Factor = 1.339	6.52%

Note: The proportions of equity and debt capital used by DEA are arithmetically wrong. The Department has corrected these errors.

Dakota Electric's overall Rate of Return on Rate Base (6.52%) is:

Weighted Cost of Capital (4.87%) (times) the Ratio of Total Capital to the Rate Base (1.339)[94]

The overall rate of return of 6.52 percent applied to the initial proposed rate base of $171,614,000 yielded a required return of $11,191,000.

DEA's choice of 5.31% as the cost of debt accurately reflects the proportion of the total annualized interest expense ($5,220,915) on all long term loans to the estimated balance of loans

[92] Ex. 101, Larson Direct at 13-14.
[93] Ex. 101, Larson Direct at 15.
[94] The Ratio of Total Capital to the Rate Base is the rate base factor. According to Dakota electric, "Rate of return on rate base is not a financial performance metric used by Dakota Electric's Lenders." [Ex. 101, Larson, Direct, p. 16]

($98,336,368).[95] DEA's total capitalization of $229,589,977 is the sum of equity ($136,837,360) and debt ($92,752,617) as of 2013. However, the debt and equity ratios of the capital structure do not follow this composition of capital.[96]

Department's Analysis

The Department noted that while DEA has used the appropriate methodology to estimate the rate of return on equity and the overall rate of return, DEA has used an inappropriate equity ratio, debt ratio and total capitalization.[97]

The Department noted that an adequate return on equity capital (patronage capital) is that which allows DEA to maintain appropriate debt coverage, support an appropriate level of rate base growth and ensure consistent retirement of capital credits.[98]

The Department concluded that a debt ratio of 46.715 percent does not reflect DEA's refinancing of some of its long-term debt.[99] The Department noted that DEA's use of a debt level of $92,752,617 was associated with the amount of debt prior to the refinancing of three outstanding loans. DEA refinanced these loans by issuing new loans in early 2014. The Department pointed out that the 5.31% cost of debt corresponded to a loan balance of $98,336,368 (DEA-2, p. 4 of 8) and this amount is the correct amount of debt to use in rate of return calculations.

The Department rejected DEA's use of the 53.285% equity ratio because it is the average projected equity ratio for the years 2022 and 2023.[100] The Department retained DEA's estimate of the amount of equity ($136,837,360) but revised the amount of debt to $98,336,368 for a total capitalization of $235,173,728. The equity ratio then works out to 58.19%.[101] This equity ratio is consistent with the Department's use of 41.81% debt ratio[102] and level of debt of $98,336,368.[103]

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[95] Ex. 103, Exhibit (DEA-2), page 4 of 8.
[96] As the Department points out (Ex. 300, Dr. Amit Direct at 11), total capitalization of $229,589,977 for 2013 results in an equity ratio of 59.60 percent.
[97] Ex. 300, Dr. Amit Direct at 19-20.
[98] Ex. 300, Dr. Amit Direct at 6-7.
[99] Ex. 300, Dr. Amit Direct at 20.
[100] Ex. 300, Dr. Amit Direct, footnote at 9.
[101] Ex. 300, Dr. Amit Direct at 11:2-4.
[102] Ex. 300, Dr. Amit Direct at 13.
[103] Ex. 300, Dr. Amit Direct at 14.

The following table provides a comparison of the inputs used by the Department and DEA:[104]

Table 8

Type	Department	DEA
Equity Ratio	58.19%	53.285%
Debt Ratio	41.81%	46.715%
Test Year Total Capital	$235,173,728	$229,589,977
Test Year Total Debt	$98,336,368	$92,752,617

The Department's revisions to the capital structure and the resulting rates of return are summarized below:

Table 9

Type of Capital	Amount	Proportion	Cost	Weighted Cost
Equity	$136,837,360	58.19%	4.28%*	2.49%
Debt	$ 98,336,368	41.81%	5.31%	2.22%
Total/Weighted Cost of Capital	$235,173,728	100.00%		4.71%•

Note:[105]

* In the Department's direct testimony, the cost of equity was erroneously reported as 4.35%. This number was also memorialized in the Settlement Agreement between the Department and DEA. However, in the Amended Settlement, the Department corrected the 4.35 percent to 4.28 percent. The revision is incorporated in the ALJ's report.

• The overall or weighted cost of capital initially calculated by the Department, based on the cost of equity of 4.35%, was 4.75%. However, the correction to the cost of equity, as noted above, resulted in a corresponding correction of the weighted cost of capital from 4.75% to 4.71%. This correction is noted in the Amended Settlement.

The Department indicated, as noted earlier, that while for a "typical" utility, the test year rate base is equal to or only slightly different from total capitalization, for DEA the overall rate of return on total capital must be adjusted to allow DEA to earn the same amount on its rate base as it would earn on its total capitalization.

The Department noted that the weighted cost of capital ought not to be applied directly to DEA's rate base. The Department added that because DEA purchases equity capital only from its members and because the members are required to invest in DEA in order to receive any electric service, and since DEA does not pay dividends out of its earnings, DEA's required rate of return on equity would be lower than its true cost of equity capital. In order to allow both bondholders and equity holders (who are DEA 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.[106] The Department also pointed out that DEA is required to pay patronage capital

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[104] Ex. 300, Dr. Amit Direct at 21.

[105] The cost of equity is given by the formula: g + $2,500,000/(ER*TCt), where g = 2.45 percent, is the growth rate of equity capital; $2,500,000 is equity capital per year required to meet capital credit obligations; ER = 0.5819 is the test-year equity ratio, and TCt = 235,173,728, is test-year total capitalization. Straightforward substitution of these values into the formula gives the cost of equity as 4.28 percent.

[106] Ex. 300, Dr. Amit Direct at 17:14-22.

to its members, making such payments to equity holders similar to the required interest payments to bond holders.

The appropriate adjustment is shown below:

Weighted Cost of Capital (times) Total Capitalization	(should equal)	Overall Return on Rate Base (times) the Rate Base,

that is,

4.71% (times) $235,173,728 = Overall Return on Rate Base (times) $171,181,006.[107]

The Overall Return on Rate base then equals ($235,173,728/$171,181,006)*0.0471 = **6.47%**.[108]

In the amended Settlement, the Department noted a revised revenue deficiency of $4,358,994.

In this conceptualization, any revisions made by the Commission to the rate base will change the overall rate of return on rate base by affecting the denominator in the above formula.

DEA's Response[109] to the Department's Revisions

DEA, in Larson's Rebuttal Testimony, agreed to the Department's input refinements and overall rate of return calculations. DEA noted that the Department's methodology was consistent with the methodology approved in DEA's last general rate case, with the inclusion of a refinement for the long-term debt adjustment the Cooperative reflected in the test year for certain loans refinanced in early 2014.

Settlement Agreement between DEA and the Department

On January 5, 2015, DEA and the Department filed their Settlement. In the Settlement Agreement, the two parties agreed to the Department recommended rate base of $171,181,006 and the resulting overall rate of return on rate base of 6.53 percent, based on the Department's direct testimony.

Amendment to the Settlement Agreement between DEA and the Department of Commerce

On January 20, 2015, DEA and the Department filed an amendment to their previous Settlement Agreement.

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[107] The rate base of $171,613,635 was initially proposed by DEA. The Department recommended a lower rate base of $171,181,006 in the Settlement which DEA accepted. See Department Initial Post-Hearing Brief, p. 20.
[108] In the Department's direct testimony, the overall rate of return on rate base was estimated to be 6.51% based on the cost of equity of 4.35%, cost of debt of 5.31%, rate base of $171,613,635, and total capitalization of $235,173,728. See Ex. 300, Dr. Amit, Direct Testimony, p. 19.
[109] Ex. 126, Larson Rebuttal at 4:1-5.

As was noted earlier, the Department noted that it discovered a math error in the calculation of its recommended return on equity of 4.35% and that the figure should have been 4.28% and that neither the methodology nor the formulae used by the Department was affected by the math error.

The following table presents the corrected rate of return calculations:

Table 10

	Original	**Revised**
Cost of Equity	4.35%	4.28%
Cost of Debt	5.31%	5.31%
Overall Cost of Capital	4.75%	4.71%
Overall Return on Rate Base	6.53%*	6.47%
DOC Revenue Deficiency	$4,454,787	$4,358,994

*In this calculation of 6.53%, the Department used its revised rate base of $171,181,006 and its estimate of total capitalization from its direct testimony.

Parties' Response to the Amended Settlement Agreement

No party objected to the amended settlement regarding capital structure or the various rates of return.

DEA's Compliance Filing

DEA's Compliance filing of March 9, 2015 duly reflects the **overall rate of return on rate base of 6.47% and applies it to the Department-recommended rate base of $171,181,006** to yield a required return of $11,078,195.[110] When taken together with the total revenue requirement and present tariffed revenue and other operating revenue, the revenue deficiency is shown in the Compliance filing to be what the Department estimated -- $4,358,994.

ALJ's Analysis and Recommendation

The amended settlement and the parties' briefs and reply briefs preceded the publication of the ALJ's findings.

The ALJ discussed DEA's capital structure, rate of return, and return on equity in ¶¶ 32-43, pp. 7-9, of Section IV. B of her report.

These paragraphs (without footnotes) are reproduced below:

> 32. The Settling Parties agreed on the following principles and outcomes in determining DEA's capital structure, rate of return, and return on equity.

[110] DEA Compliance Filing, March 9, 2015, Exhibit DEA-2 (updated), p. 1 of 8.

33. Department witness Dr. Amit determined that, because the overall rate of return is applied to the rate base to produce the appropriate level of net income, the overall rate of return must be adjusted to allow DEA to earn the same amount on its rate base as it would on its total capitalization.

34. The Department noted that its recommended return on equity (ROE), cost of debt, and the resulting overall rate of return (ROR) are based on DEA's initially filed test year rate base of $171,613,635 and that, if the Commission approves a different rate base, then the return should be adjusted.

35. Given its specific nature as a cooperative utility, the required return on DEA's equity is not determined by the opportunity cost of investing capital somewhere else. Instead, it is determined by the need to finance the growth of DEA's rate base and maintain a sound capital structure.

36. Unlike an investor-owned utility (IOU), DEA has a unique feature: all of its ratepayers are required to invest in DEA and are also the only investors in DEA. The equity portion of the capitalization of DEA is properly termed "Patronage Capital," because it is collected from the utility's customers through rates. This is to say that a portion of every customer's electric bill is "earmarked" as capital credits and used to maintain a sound capital structure. These capital credits must be returned to DEA's customers on a regular basis. Based on its historical experience, DEA determined that it needs to return $2,500,000 per year as capital credits.

37. An adequate rate of return on equity capital (patronage capital) is a return that allows DEA to: 1) achieve or maintain an appropriate debt coverage; 2) maintain an appropriate level of rate base growth; and 3) ensure consistent retirement of capital credits.

38. To meet these financial requirements, the Department estimated a cost of equity for DEA of 4.28 percent.

39. DEA's capital structure, amended to reflect DEA's refinancing of long-term debt in January 2014, is as follows:

Component	Amount	Capitalization
Equity	$136,837,360	58.19%
Debt	$98,336,368	41.81%
Total	$235,173,728	100.00%

40. As applied to total capitalization, the Department recommended an overall rate of return of 4.71 percent; however, as applied to the rate base, the Department recommended an overall rate of return of 6.47 percent. This rate is based on Dr. Amit's recommended rate of return on common equity of 4.28 percent, a cost of debt of 5.31 percent, and overall return on total capital of 4.71 percent. If the Commission approves a rate base different than $171,613,635, then the return should be adjusted as follows:

> Overall return on rate (ROR) on rate base = 4.71 x Total Capitalization/Approved Rate Base.

41. The Department ultimately recommended a lower rate base of $171,181,006, which DEA accepted. Adjusting for a reduced rate base, the Department calculated a new overall rate of return of 6.47 percent. DEA agreed that the Department's capital structure, ROE, and ROR calculations are reasonable. DEA's agreement with the Department's analysis and conclusions is reflected in the parties' Settlement Agreement. The OAG did not object to the recommended capital structure, ROE, or ROR.

42. Based on the adjusted amount of the agreed-upon rate base of $171,181,006 and the corrected ROR calculations as reflected in the Amended Settlement Agreement, the Settling Parties agreed on the following ROR calculations:

	Original	Revised
Equity Cost	4.35%	4.28%
Debt Cost	5.31%	5.31%
Overall Cost of Capital	4.75%	4.71%
Overall Return on Rate Base	6.53%	6.47%
DOC Revenue Deficiency	$4,454,787	$4,358,994

43. The Administrative Law Judge agrees and also finds that all of the parties' recommendations for DEA's capital structure, ROE, and ROR are reasonable.

Under Conclusions of Law, point 6, p. 43 of the ALJ's report, the ALJ notes:

6. The record supports the resolution of the settled, resolved, and uncontested matters set forth in Section IV of this Report. These matters have been resolved in the public interest and are supported by substantial evidence.

Staff Recommendation

Staff recommends that the Commission adopt the ALJ's findings in their entirety, ¶¶ 32-43, pp. 7-9 of the ALJ's report. If the Commission approves a different rate base than $171,181,006, the overall rate of return on rate base would have to be recalculated as noted below in Option A.

Decision Alternatives – Cost of Capital

(Note: The following decision alternatives correspond to 7:A-B in the Deliberation Outline, p. 6.)

A. Adopt the ALJ's conclusion that the record supports the following resolution of the issues involving DEA's proposed capital structure, rate of return, and return on equity, and approve the following:

1. Capital Structure (58.19% equity; 41.81% debt)

Type of Capital	Amount	Percent
Equity	$136,837,360	58.19 percent
Long Term Debt	$98,336,368	41.81 percent
Total/ Weighted Cost	$235,173,728	100.00 Percent

2. Weighted Cost of Capital (4.71%)

Type of Capital	Composition	Cost	Weighted Cost
Equity	58.19 percent	4.28 percent	2.49 percent
Long Term Debt	41.81 percent	5.31 percent	2.22 percent
Total/ Weighted Cost	100.00 percent		4.71 percent

3. Overall Rate of Return on Rate Base (6.47 %)
(on the condition that the rate base is $171,181,006 and calculated as follows)

0.0471 * (Total Capitalization / Rate Base), i.e.,

0.0471 * ($235,173,728/$171,181,006) = 6.47 percent; **or**

B. Take some other action.

Relevant Documents

- Douglas R. Larson (DEA), Direct (Ex.101), Rebuttal (Ex. 126), and Surrebuttal Testimony with Attachments (Ex. 127).
- Dr. Eilon Amit (Department), Direct Testimony with Attachments (Ex. 300).
- Settlement Agreement between DEA and the Department of Commerce, January 5, 2015 (Ex. 128).
- DEA's Issues Matrix, January 9, 2015.
- Amendment to the Settlement Agreement between DEA and the Department of Commerce, January 20, 2015 (Ex. 128A).
- Department Initial Post-Hearing Brief, January 20, 2015.
- DEA Compliance Filing, March 9, 2015.
- ALJ's Findings of Fact, Conclusions of Law and Recommendations, March 2, 2015.

Sales Forecast (Resolved)

PUC Staff: Ganesh Krishnan

Statement of the Issue

Should the Commission approve DEA's proposed energy sales volumes and budgeted customer counts?

Introduction

Both the Department and the ALJ recommend the Commission approve DEA's proposed energy sales volumes and budgeted customer counts. No other party commented on DEA's sales forecast.

In the one paragraph, ¶ 44, of Section IV. C, addressing this issue, the ALJ concluded:

> 44. DEA's filing included a weather-normalized energy sales forecast. The Department analyzed and approved DEA's calculations of test year energy sales volumes and customer counts. The Settlement Agreement reflects the Settling Parties' agreement regarding DEA's energy sales volumes and customer counts.

Under Conclusions of Law, point 6, the ALJ noted:

> 6. The record supports the resolution of the settled, resolved, and uncontested matters set forth in Section IV of this Report. These matters have been resolved in the public interest and are supported by substantial evidence.

Importance of Correctly Estimating Test-Year Sales and Customer Count

As the Department indicated,[111] test-year sales volumes are important factors in calculating a utility's revenue requirement because sales levels affect both revenues and expenses. In general, lower sales levels produce higher rates, since costs are spread over fewer units. Because sales levels are an integral input in calculating a utility's rates, the method of determining the sales levels must be reasonable.

DEA's Weather-Normalized Sales and Customer Count

DEA serves some twenty-three rate classes or customer categories out of its tariffs. Of these, the residential and farm service (Rate Class 31) is the most significant in terms of both customer count, and energy sales and revenue.

In terms of recorded data for the year 2013, residential and farm service accounted for 94,890 customers (93-percent), 868,441,013 in Kwh sales (47-percent), and $110,807,384 in revenue

[111] Ex. 306, Michael Zajicek (Department) Direct Testimony at 2.

(57-percent).[112] It is the sales to this class of customers which is most sensitive to weather changes and thus weather-normalization of sales to this class is crucial for proper rate-making.

For the pro forma test year, DEA has proposed a customer count of 95,586 for residential and farm service and energy sales of 879,773,544 Kwh.

The following table compares the recorded data for the year 2013 with the pro forma test-year data used by DEA (Source: Larson Direct, Exhibit DEA-1, pp. 11-12; Larson Direct, p. 10):

Table 11

Col 1	Col 2	Col 3	Col 4	Col 5
Customer Class	**Customers Recorded, 2013**	**Budgeted Customers, Pro Forma Test Year, 2014[113]**	**Energy Sales, Recorded 2013**	**Energy Sales, Pro Forma Test Year, 2014**
Residential & Farm Service (31)	94,890	95,586	868,441,013	879,773,544
Residential & Farm Demand Control (32)	16	18	412,493	442,584
Electric Vehicle (33)	5	5	10,359	13,080
Irrigation Service (36) Firm	9	9	327,522	273,780
Irrigation Service (36) Interruptible	352	340	13,424,323	10,342,800
Small General Service (41)	4,420	4,630	49,952,917	53,504,280
Security Lighting Service (44)	1,224	1,214	746,392	714,480
Street Lighting Service (44-2)	2,467	2,480	2,579,881	2,599,800
Street Lighting System (44-1)	473	474	487,440	484,680
Custom Residential Street Lighting (44-3)	11,885	11,944	6,518,830	6,566,880
Low Wattage Unmetered Service (45)	54	54	-	-
General Service (46)	2,357	2,316	438,800,951	446,839,776
Municipal Civil Defense Sirens (47)	65	65	-	-
Geothermal Heat Pump (49)	3	5	242,211	387,300
Controlled Energy Storage (51)	1,280	1,346	9,153,812	9,529,680
Controlled Interruptible Service (52)	6,403	6,648	47,151,997	46,828,512
Residential & Farm Time of Day (53)	18	19	215,931	246,468
General Service Time of Day (54)	8	8	4,698,960	4,934,016
Standby Service (60)	1	1	28,224	-
Full Interruptible Service (70)	211	211	395,002,219	408,431,856
Partial Interruptible Service (71)	27	28	24,105,344	26,293,344
Cycled Air Conditioning Service (80)	39,172	39,480	4,910,478	5,666,000
Total[114]	102,314	103,171	1,862,300,819	1,898,206,860

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[112] Source: Ex. 101, Larson Direct Testimony, Exhibit DEA-1, p. 11 of 20.
[113] The supporting material for budgeted customers is in Ex. 306, Department Exhibit MNZ-1, pp. 2-4.
[114] The total number of consumers excludes Security, Street & Residential Lighting, Low Wattage Unmetered Service, Municipal Civil Defense Sirens, Controlled Off-Peak Energy Storage, Interruptible Heating, and Controlled Air Conditioning Service.

Pro Forma Test Year consumers are based on DEA's average number of 2014 budgeted consumers. The budgeted number of customers and energy sales for the pro forma test year (columns 3 and 5 in the above table) form the billing determinants (or units) in the calculation of revenue under the present and proposed rates. The revenues from present and proposed rates are given in Larson Direct, p. 8.

In determining the revenue from present and proposed rates, for the residential and farm service, DEA notes that "[t]he forecasted billing units rely on regression analysis for the residential rate class which is most sensitive to fluctuating consumption based on changing weather."[115] "For those classes that do not experience such consumption fluctuations due to weather, the Test Year billing units reflect average energy and demand for each class multiplied times budget average number of members for the respective classes."

For the residential and farm customer class (Rate Class 31), "the most weather sensitive rate class, energy sales are based on a regression analysis using 13 years' of average monthly sales (2001-2013), weather normalized (using 20 years of weather), multiplied by budgeted 2014 number of customers."[116] After normalizing the energy sales data on a monthly basis per customer, for the years 2001 through 2013, through regression analysis, DEA identified the average monthly weather-normalized sales for the most recent five years per customer. This average monthly weather-normalized sale per customer works out to 767 Kwh.[117] This figure is then multiplied by 12 to get the yearly sales estimate per customer and then multiplied by the budgeted number of customer for the year 2014 (95,586 from the above table) to obtain the total weather-normalized sales,

767 Kwh/month/customer * 12 months * 95,586 budgeted customers =
879,773,544 Kwh/year weather-normalized sales.

For the other customers classes, DEA did not weather-normalize sales as it was found less necessary than the residential class. In general, DEA's methodology is to generate an average per month, per customer, Kwh estimate from historical data, and then to convert this data to annual total sales by multiplying by a factor of 12 and by the number of estimated customers for the pro forma test-year.

For some rate classes, notably small general service (Rate Class 41), general service (Rate Class 46) and interruptible service (Rate Class 71), the energy sales for the pro forma test year are derived by simply taking the average Kwh per month per customer for the years 2009 through 2013, then multiplying this figure by 12 and then by the budgeted number of customers for the year 2014. For the interruptible rate service, Rate Class 70, DEA used a three-year average (2011-2013) because of "the addition of several meters at the Minnesota Zoo in 2010 with no corresponding increase in Kwh usage."

DEA observed that rate classes 31, 41, 46, 70 and 71 represented 99.6% of DEA's member count and 95.6% of its kWh forecast for the test year.[118]

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[115] Ex. 101, Larson Direct at 11.
[116] Ex. 122, DEA Workpaper 13, p. 1 of 12.
[117] Ex. 122, DEA Workpaper 13, p. 3 of 12.
[118] Ex. 306, Department Exhibit MNZ-1, p. 2.

Department Analysis

The Department supports DEA's energy sales forecast methodology and estimates of sales volume and customer count. The Department recommends[119] that the weather-normalized sales volumes that result from DEA's forecasts be used for the residential customer class. The Department also recommends that the test-year sales volumes that result from DEA's calculations be used for the remaining rate classes: the small general service rates classes (Rate 41), the general service (rate 46), full and partial interruptible service (Rates 70 and 71) and the other rate classes.

Settlement Agreement between DEA and the Department

In the Settlement Agreement, DEA and the Department recommend that the Commission approve DEA's energy sales volumes and budgeted customer counts in this proceeding.[120]

Other Parties' Position

No other party commented on DEA's energy sales and customer forecast.

ALJ's Findings

The ALJ found:

> 44. DEA's filing included a weather-normalized energy sales forecast. The Department analyzed and approved DEA's calculations of test year energy sales volumes and customer counts. The Settlement Agreement reflects the Settling Parties' agreement regarding DEA's energy sales volumes and customer counts.

Decision Alternatives – Sales Forecast

(Note: The following decision alternatives correspond to 8:A-B in the Deliberation Outline, p. 6.)

A. Approve DEA's proposed test-year energy sales volumes and budgeted customer counts. **<u>or</u>**

B. Take some other action.

Relevant Documents

- Douglas R. Larson (DEA), Direct Testimony with Attachments (Ex. 101).
- Michael Zajicek (Department) Direct Testimony and Attachments (Ex. 306).
- Settlement Agreement between DEA and the Department of Commerce, January 5, 2015 (Ex. 128).
- Department Initial Post-Hearing Brief, January 20, 2015.
- ALJ's Findings of Fact, Conclusions of Law and Recommendations, March 2, 2015.

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[119] Ex. 306, Zajicek Direct at 3.
[120] Ex. 128, Settlement Agreement, p. 10.

Class Cost of Service Study (CCOSS)

PUC Staff: Andy Bahn

Statement of the Issue

Should the Commission approve DEA's Class Cost of Service Study (CCOSS)?

Introduction

In her Report, the ALJ stated that the purpose of a CCCOSS is to identify, as accurately as practicable, the responsibility of each customer class for the costs incurred by the utility to provide service for that class. Further, the ALJ stated that the CCOSS assigns costs to each customer group that imposes costs on the system and it should provide for the equitable allocation of costs amongst all customer classes in a manner that most accurately represents the true nature of the factors that cause the costs to be incurred (cost causation).[121]

In addition, the ALJ stated that a CCOSS is comprised of three main steps:[122]

1) Functionalization, which groups costs based on their purpose (or major function, for example, production of electricity, transmission of electricity, distribution of electricity, and general);
2) Classification, which refines the functionalized costs by identifying the utility operation on which the costs are spent (for example, are the costs customer-related, demand or capacity-related, or energy-related); and
3) Allocation, which assigns costs to customer classes based on the cost impact each class imposes on the system.

DEA's Proposed CCOSS

DEA described its methodology as the fully-allocated, average, embedded CCOSS approach. According to DEA, a fully-allocated, average, embedded CCOSS means that costs used in the analysis are allocated on an average system-wide basis and the costs are embedded, meaning the costs used in the study are the historical costs recorded in DEA's books.[123]

DEA described the basic procedure used to determine the cost responsibility of each consumer classification as using the following steps:[124]

Step 1: Classify the plant account records into basic cost causative categories.

Step 2: Classify the Test Year expenses and margin requirement into the same cost causative categories.

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[121] OAH, *Findings of Fact, Conclusions of Law and Recommendations,* March 2, 2015, ¶ 75, p. 18.
[122] *Id*., ¶ 77, p. 19.
[123] Ex. 101, Larson Direct, p. 20.
[124] *Id*, p. 23.

Step 3: Develop allocation factors for each rate class.

Step 4: Allocate costs to the various rate classes using the class allocation factors developed for each cost causative category.

(Staff notes that because DEA is a distribution-only electric utility the functionalization step in the class cost of service study is not a significant part of the analysis.)

DEA cautioned that the CCOSS has certain limitations that the Commission should be aware of when basing decisions on the study. According to DEA, "[i]t is vital at the outset to recognize some of the inherent limitations of such a study," for the following reasons:[125]

- CCOSS analysis is an art; not an exact science. There are many different methodologies, techniques and assumptions that have been and will continue to be advocated by rate analysts. Because the various philosophies and assumptions can affect the results of the analysis, the results should be treated as providing an indication of the general range of class cost responsibility; and not as precise values.

- CCOSS analysis is of necessity directed at determining the cost imposed by a rate class on the system rather than at determining the cost imposed by individual customers within each classification. The cost responsibility of a specific, individual consumer may or may not be entirely consistent with the cost allocations made to his assigned consumer classification.

- Accurate demand characteristics and load factor data for individual customer classes are often unavailable. Capacity allocations must therefore be made on the basis of estimates or "typical" data. These assumptions or estimates can have an effect on the end results; and

- CCOSS analysis does not address itself to many of the other legitimate objectives of rate design such as:

    - Member acceptance;
    - Avoidance of excessively abrupt changes from the historical rate policies of the cooperative;
    - The need to keep each rate schedule competitive, in as much as possible, with the corresponding rate schedule of neighboring utilities; and
    - The need to keep the rate structure simple so that it is easily administered and understood by members.

DEA stated that a CCOSS study can still provide a useful guideline for apportioning cost responsibility (i.e., revenue requirements) to each of the customer classifications in a manner which avoids unjustifiable price discrimination, with the above limitations in mind. According

[125] *Id*., p. 22.

to DEA, a CCOSS study also provides information useful in designing the individual rate schedules and provides support for justifying rate differentials to retail members.[126]

DEA stated further that the CCOSS model in this rate case is the same model approved by the Commission in its last rate case, with two modifications. The two modifications are as follows:[127]

- In compliance with the final Order in DEA's 2009 general rate case, which required that DEA either use the minimum-size method to classify distribution accounts, or provide such an analysis to support the outcome of the zero-intercept method shall, in its next rate case, DEA chose to use the minimum-size method to classify specified distribution accounts.

- Because DEA's wholesale power supplier has implemented a new ancillary service energy charge, the new CCOSS distributes these ancillary service energy costs into each energy cost component based upon the kWh purchases and the ancillary services rate.

DEA noted the Commission's final Order in DEA's 2009 general rate case in Docket No. E-111/GR-09-175, ordering paragraph 6 required DEA to choose between two options for a minimum system study to classify distribution accounts:[128]

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

According to DEA, the purpose of a minimum system study is to determine the proportion (percentage) of certain plant accounts that should be classified as either consumer or capacity. DEA stated that after these costs are classified, they are then allocated to classes based on appropriate cost-causation allocation factors.[129]

DEA stated further that while it is important to properly classify certain distribution plant as consumer or capacity, reasonable deviations in such classification do not have significant impacts on the CCOSS results.[130]

In compliance with the Commission's Order, DEA chose to use the minimum-size method to classify the specified distribution accounts in this rate case, rather than the zero-intercept method with supporting analysis.[131]

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[126] *Id.*, p. 23.
[127] *Id.*, pp. 20-21.
[128] *Id.* p. 20.
[129] Ex. 126, Larson Rebuttal, pp. 19-20.
[130] *Id.* p. 20.
[131] Ex. 101, Larson Direct, p. 21.

According to DEA, after the overall revenue requirements analysis was complete, the CCOSS analysis was prepared by Power System Engineering, Inc. The results of the CCOSS analysis prepared by Power System Engineering were summarized in the following table:[132]

Cost of Service Summary				
Rate Class	**Revenue Present Rates**	**Cost of Providing Service**	**Increase (Decrease)**	
			Amount	**Percent**
	($)	($)	($)	(%)
Residential & Farm (31,32,53)	112,384,414	115,576,812	3,192,398	2.85
Small General Service (41)	6,674,522	7,171,338	496,817	7.47
Irrigation (36)	977,226	997,009	19,783	2.03
General Service (46,54)	47,909,060	47,749,413	(159,647)	-0.33
C&I Interruptible (70,71)	26,594,877	27,212,425	617,548	2.33
Lighting	1,999,160	2,021,495	22,335	1.12
			Total System	2.11

DEA noted that required revenue changes are very similar for most classes, except Small General Service Schedule (41). DEA cautioned that, due to the limitations inherent to a CCOSS analysis, the results should be viewed as providing a general range of where rates should be and that it is, in fact, uncommon for rates to be designed exactly in line with CCOSS results.[133]

Position of the Parties

The Department recommended the Commission adopt DEA's proposed CCOSS.[134]

The OAG, however, stated that it believes DEA's CCOSS over estimates customer costs and therefore overly burdens residential and farm and small general service classes by assigning undue costs within DEA's CCOSS. Specifically, OAG disputed DEA's minimum system study for determining which portion of the distribution costs should be allocated to consumers (customers) and which should be allocated to capacity (demand). The OAG did not agree with the Department and DEA that DEA's minimum-size method analysis provides a reasonable basis for determining distribution costs. Instead, the OAG proposed a "zero-intercept proxy" method as an alternative to DEA's minimum-size method.

[132] *Id.*, p. 7.
[133] *Id.*
[134] Ex. 301, Ruzycki Direct, p. 15.

The Department

The Department stated that DEA appears to have followed the classification and allocation guidelines set about in the 1992 NARUC Electric Utility Cost Allocation Manual (NARUC Electric Manual). In addition, the Department stated it agreed with the decisions made by DEA in functionalizing, classifying and allocating costs in this CCOSS.[135]

The Department described the two methods for determining a minimum system: the minimum-size method and the zero-intercept method. The Department stated that the minimum-size method determines the minimum size for each piece of equipment currently installed by the utility to serve the minimum loading requirement of customers and is described in the NARUC Electric Manual. According to the Department, this method assumes that a least size distribution system can be built to serve the minimum load requirements of the customer base.[136]

The Department described the zero-intercept method as using an estimated linear relationship between the unit cost of distribution equipment and the size of the equipment.[137] The Department stated that given a specific component of a certain size, it is assumed that as the current carrying capability of the component increases, the costs increase commensurately.[138]

DEA chose to use the minimum-size method and the Department concluded that DEA's assumptions regarding the minimum size equipment selected for the analysis were reasonable, because they were "grounded in reality," and they reflect the real world minimum size equipment needed to serve customer load.[139]

The Department stated it reviewed the allocation factors through which capacity costs were allocated to different consumer classes in the electronic version of the CCOSS submitted by DEA, and determined that the factors and methodology to derive the factors were generally reasonable.[140] The Department also concluded that the proposed CCOSS is reasonable, because

[135] *Id*., p. 14.
[136] *Id*., p. 8.
[137] The equation used to estimate the relationship between the unit cost of the distribution equipment and the size of the equipment was described by the Department as follows:

$$Y = a + bx$$

Where, Y represents the per-unit installed cost of the equipment;
x represents the size or capacity of the equipment; and
a and b represent the intercept and the slope of the line, respectively.

According to the Department, by using the utility's system equipment and cost data, the theoretical minimum size (x) can be set to zero, and the intercept (a) will represent the cost of the equipment that does not depend on the size of equipment installed. The cost of the equipment at zero-size is considered the customer component, and the remainder of the cost is classified as demand related. See Ex. 301, Ruzycki Direct, p. 19.
[138] *Id*., p. 9.
[139] *Id*., p. 11.
[140] *Id*., p. 14.

DEA used the same methodology that was approved by the Commission in its last rate case with the exception of the two changes, which the Department believes were reasonable.[141]

OAG

The OAG did not agree with the results of DEA's CCOSS. Specifically, the OAG disagreed with DEA's choice for the use of a minimum system study to classify the costs of its distribution system, such as poles, conductors and transformers, which are contained in FERC accounts 364-368.[142] According to the OAG, DEA's incorrect classification of costs related to distribution system plant accounts increased the cost burden on the residential class, since it pays a significantly greater portion of the costs that are classified as customer costs.[143]

The OAG noted that FERC accounts 364-368 contain both customer and demand costs and a minimum system study is conducted to determine the proportion of these FERC accounts that should be classified as customer costs and the proportion that should be classified as demand costs. The OAG stated that the minimum system study estimates the hypothetical, minimum distribution system necessary simply to provide service to customers, without consideration of a customer's demand. The OAG also stated that the minimum system is classified as the customer cost portion of the utility's actual distribution system, while any distribution costs above those of the minimum system are classified as demand.[144]

The OAG stated that the main task within the minimum system study is to create a hypothetical minimum system and estimate its cost. According to the OAG, the issues most disputed in a minimum system study are determining the minimum sized distribution equipment that should be used in the analysis and estimating the unit cost of the equipment used to create the minimum system.[145]

Like the Department, the OAG cited the NARUC Electric Manual as a guideline for how to create a minimum system study. The OAG stated that the minimum system approach uses the minimum sized distribution equipment to serve the hypothetical minimum or zero-loading requirements of the customer. The OAG stated further that the theory of the minimum system is that any distribution equipment larger than the minimum required that has been installed for the company to meet demand are separate from and in addition to the costs to connect a customer to the system. The importance of this distinction, according to the OAG is that, under cost causation theory, the variable demand costs should be allocated differently than the fixed customer costs.[146]

The OAG stated there are two methods that the NARUC Electric Manual uses to construct a minimum system: the minimum-intercept (or zero-intercept) and minimum-size methods.[147]

[141] *Id*.
[142] Ex. 200, Nelson Direct, p. 3. The OAG did not disagree with DEA's classification contained in other FERC accounts.
[143] OAG Post Hearing Brief, January 20, 2015, p. 14.
[144] Ex. 200, Nelson Direct, p. 5.
[145] *Id*., p. 7
[146] *Id*., p. 5.
[147] *Id*., p. 6.

According to the OAG, the zero-intercept method uses the unit cost of a hypothetical no-load or zero-intercept to calculate the cost of a minimum system. The OAG cited the NARUC Electric Manual for a description of the minimum-size method:[148]

> (t)he minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero intercept method.

The OAG stated that the minimum sized distribution equipment has some load-carrying capacity and some of the demand costs are classified as customer costs by including these costs in the minimum system. The OAG noted that the NARUC Electric Manual addresses this on page 95:[149]

> (T)he analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as demand-related cost….When allocating distribution costs determined by the minimum-size method … some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

According to the OAG, the minimum-size method is often used due to its simplicity. However, this method overestimates customer costs because incremental increases in equipment size or load capability are linked to demand rather than customer costs. On the other hand, the zero-intercept method is theoretically more accurate because it constructs a minimum system devoid of material costs and where demand is equal to zero. According to the OAG the zero-intercept method avoids several problems inherent with the minimum-size method because a no-load system has no (zero) demand component.[150]

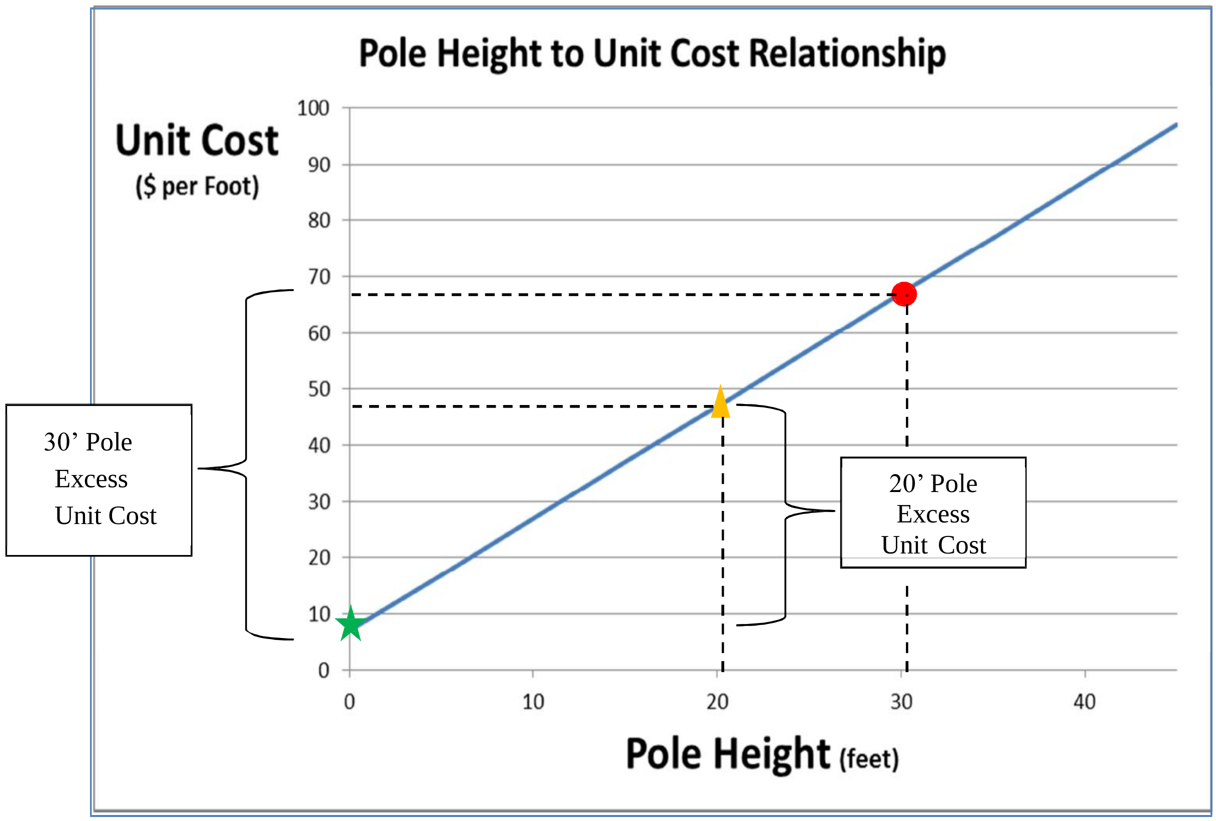
In addition, the OAG stated that the two methods calculate the cost of the minimum system using different procedures. The zero-intercept method uses an econometric regression analysis to calculate the unit cost of the no-load equipment, while the minimum size method simply uses the average unit cost of the smallest installed equipment. Therefore, the OAG concluded that the zero-intercept method is more technically demanding.[151]

According to the OAG, each method assigns a different proportion of the distribution system's costs as demand and customer costs and the exact proportions that the zero-intercept and

[148] *Id*.
[149] *Id*., p. 15.
[150] *Id*., pp. 6-7.
[151] *Id*., p. 7.

minimum-size methods assign to demand and customer costs are case dependent. The OAG stated that the zero-intercept method would theoretically assign a smaller proportion of the distribution system's costs as customer costs than would the minimum-size method.[152]

The OAG provided the following graph as an example of how using the cost of either a 20-foot or 30-foot utility pole in a minimum size method overstates the customer cost portion of a utility's distribution system:[153]



In this graph, the OAG explained that the blue line represents a hypothetical regression line demonstrating the cost of utility poles as they get taller to serve more demand. The OAG marked the location of where the line crosses the Y-axis with the star (at approximately the point where the unit cost equals $8 per foot), to represent the optimal unit cost to construct a minimum system where the pole height equals a no-load scenario. According to the OAG, the star represents the optimal unit cost to construct a minimum system because it does not include any demand costs.[154]

The OAG explained further that in a zero-intercept analysis, all of the unit costs below the star would be classified as customer costs, while any unit costs incurred by the utility above the star would be classified as demand costs, since the specific heights of the poles installed by the utility would depend on customer demand. The OAG marked the location on the graph for the unit costs of installing a 20-foot pole (at approximately $48 per foot) or 30-foot pole (at approximately $68 per foot), with a triangle and a circle respectively.[155]

[152] *Id.*
[153] *Id.*, p. 9.
[154] *Id.*, p. 10.
[155] *Id.*, pp. 8-11.

The OAG stated that the above graph demonstrates that in theory the minimum-size method, as opposed to a zero-intercept method, overestimates the proportion of customer costs to construct the minimum system, because the unit cost is too high or greater than a no-load cost. As explained by the OAG, conducting a minimum system study using either a 20-foot or 30-foot pole as the utility's minimum size pole will inevitably classify more of the utility's distribution system as customer costs than would a zero-intercept analysis, because the difference between the cost of either the circle or the triangle in the graph and the cost of the star represents the excessive customer costs of using a minimum-size method.[156]

According to the OAG the unit installed cost varies solely by the distribution equipment size, which the OAG claims is synonymous with the material cost of the distribution equipment or pole in the example above. Therefore, the theoretical difference between the unit cost of the 30-foot pole and the zero-intercept is the material cost of the 30-foot pole, since that is the only cost that is varying in the model.[157]

The OAG stated that an estimate of excess unit cost, i.e. the extra cost caused by using a 30-foot pole instead of a no-load pole, is useful because it can be used as a proxy for the zero-intercept model. The use of a proxy may be useful given that zero-intercept studies involve an often disputed econometric regression analysis.[158]

The OAG noted that the Commission ordered DEA to use either the minimum-size method to classify distribution accounts, or provide such an analysis to support the outcome of the zero-intercept method, because of questions and concerns that arose regarding DEA's decision to use a zero-intercept method to classify FERC accounts 364-368 in its last rate case. The OAG further noted that DEA chose to use the minimum-size method in the current rate case.[159]

The OAG stated that the primary concern it had with the zero-intercept model used by DEA in the last rate case was the use of only three data points to determine the regression line and the zero-intercept, representing customer costs.[160]

The OAG noted that the Commission has acknowledged that the minimum-size method classifies some demand (capacity) costs as customer costs. As an example, the OAG cited the Commission's Order in Docket No. 13-617, which stated that "(a) minimum-size study is easier to perform than a zero-intercept study, but it results in some capacity costs being classified as customer costs since a minimum-size system carries some [capacity]."[161]

The OAG stated that, when a utility uses a minimum-size method, it is common practice in Minnesota for utilities to make an adjustment to a demand allocator to make up for the over-allocation of customer costs to certain classes and that it is possible that every utility other than DEA makes this adjustment. Although OAG stated it does not have this information available

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[156] *Id.*
[157] *Id.*
[158] *Id.*, pp. 11-12.
[159] *Id.*, pp. 12-13.
[160] *Id.*
[161] *Id.*, p. 16.

for each utility, the OAG noted that both CenterPoint Energy and Xcel Energy's CCOSS used the minimum-size method and both companies made adjustments to demand allocators to account for the capacity costs classified within the minimum system. The OAG stated that DEA made no such adjustment to its minimum-size study in its proposed CCOSS, and by not making the adjustment, DEA is placing an excessive cost allocation burden on the residential and farm class.[162]

Although the OAG did not agree with DEA's decision to use a minimum-size study in its CCOSS, it did not recommend that DEA use a zero-intercept study instead. The OAG stated that the use of either the zero-intercept or minimum-size method is not an appropriate decision to make in this case based on this record, because it is unclear how different the results of the minimum-size and zero-intercept method are; therefore it would be difficult to determine how large the demand adjustment to the minimum-size method should be.[163]

Instead of using either the zero-intercept model or the minimum- size method for determining the minimum system, the OAG recommended the Commission use its zero-intercept proxy method to estimate a minimum system for classifying the costs of DEA's distribution system.[164]

The OAG stated it developed a proxy for the zero-intercept method that does not necessitate the use of regression analysis and uses readily available data, instead. The OAG stated its proxy is based on the theory laid forth by the NARUC Electric Manual, except it uses known information as opposed to running a regression to estimate the zero-intercept.[165]

Specifically, the OAG explained the zero-intercept proxy is calculated by subtracting the material unit cost of the smallest size distribution equipment used for DEA's minimum-size method from the installed unit cost of the same sized distribution equipment to obtain the cost of installation. [166]

Because the zero-intercept assumes that the installed unit cost of the distribution equipment varies by the size or material cost of that distribution equipment, the OAG argued that subtracting the material cost from the installed cost is equivalent to obtaining the zero-intercept estimation.[167]

The OAG stated that the data required to calculate the zero-intercept proxy method is the average installed unit cost and the corresponding inventory cost of each piece of distribution equipment used within DEA's minimum size analysis. The OAG adjusted the inventory cost data for inflation and subtracted it from the installed cost data and used the results to build the minimum system by multiplying the newly calculated zero-intercept proxy cost by the number of units in the entire system, which serves as the estimate for the minimum system and the remainder of the costs are classified as capacity costs.[168, 169]

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[162] *Id*., See also Ex. 201, Nelson Rebuttal, p.4.
[163] Ex. 200, Nelson Direct, p. 17.
[164] *Id*., p. 24.
[165] *Id*., p. 20.
[166] *Id*.
[167] *Id*.
[168] *Id*.

The OAG provided the following table comparing its results using the zero-intercept method with DEA's proposed CCOSS.[170] The Table estimates each customer class' responsibility for the DEA's proposed revenue increase, or 2.11% increase for the entire system.

Comparison of CCOSS Results

	Total System	Residential & Farm	Small General Service	Irrigation	General Service	C&I Interruptible	Lighting
DEA's CCOSS	2.11%	2.85%	7.47%	2.03%	-0.33%	2.33%	1.12%
OAG's CCOSS w/ zero-intercept proxy	2.11%	0.84%	5.53%	4.38%	2.18%	6.65%	1.98%

The OAG's Response to the Department

The OAG disagreed with the Department interpretation of the minimum system theory described in the NARUC Electric and Gas Manuals and had following concerns with the Department's analysis:[171]

1) Misapplication of the minimum system theory;

2) No measurement for the error inherent when using the minimum size method; and

3) No acknowledgement that DEA did not adjust a demand allocator to account for the use of the minimum size method as is common with other Minnesota utilities.

According to the OAG, the Department's statement that "the Cooperative chose to use the smallest size equipment in service that would be necessary to serve customer load," and that "the minimum size equipment selected for the analysis are reasonable since they are grounded in

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[169] Similar to the Department's mathematical explanation of the zero-intercept model (See, fn 17 above), the OAG explained that the installed unit cost equals cost of installation plus the material cost can be written algebraically as: $y = a + z$; Where (y) represents the installed unit cost, (z) represents the material cost of the pole, and a represents the cost of installation. Staff notes that this equation is equivalent to the equation described by the Department above, where z represents bx. In the equation described by the Department, x equals the size of the equipment and b equals the slope of the line. The OAG and the Department are in agreement on what b and x represent in the zero-intercept model.

Subtracting the material cost from both sides of the equation provides an alternative calculation for the cost of installation or (a), and OAG's final zero-intercept proxy equation is expressed as: $a = y - z$. The OAG explained that the proxy method can be used to determine the costs of installation, represented by (a), which it claimed is equivalent to a no-load system according to the NARUC Electric Manual. See Ex. 200, Nelson Direct, pp 21-21.

[170] *Id.*, p. 23.

[171] Ex. 201, Nelson Rebuttal, p. 1-2.

reality, reflecting the real-world minimum size equipment needed to serve customer load" indicates a general misapplication of the minimum system theory.[172]

The OAG stated that the purpose of the minimum system study is to determine the costs of connecting a customer to the distribution system, not to determine what is necessary "to serve customer load," as the Department claimed. The OAG explained that if a utility's load is considered in developing the minimum system, some capacity costs will be incorrectly classified as customer costs. The OAG cited the NARUC Electric Manual's explanation of classifying distribution plant cost as demand cost:[173]

> Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

According to the OAG, by agreeing to classify capacity costs as customer costs, the Department is violating the theory laid forth in the NARUC Electric and Gas Manuals.[174]

The OAG also did not agree with the Department's contention that the minimum system should be "grounded in reality." The OAG stated that the minimum system study creates a hypothetical minimum system in order to identify the customer and demand costs of the actual distribution system and that there is no real minimum system to be grounded in.[175]

In addition, the OAG did not find it reasonable for the Department to claim that the minimum size method is reasonable when it does not attempt to measure the error associated with the estimates calculated using the method. The OAG explained that the Department's claim that the minimum-size method in this case is reasonable was made without understanding the error associated with this method as compared to more accurate methods such as the zero-intercept method and zero-intercept proxy calculated by the OAG.[176]

Finally, the OAG was concerned that the Department did not acknowledge that DEA's application of the minimum-size method is different as compared to some other Minnesota utilities. Specifically, the OAG explained that the Department did not acknowledge that DEA did not make an adjustment with a demand allocator to acknowledge that the minimum-size method overestimates customer costs.[177]

The Department's Response to OAG

The Department recommended that the Commission accept DEA's CCOSS for purposes of providing guidance in designing rates in this rate case only, and did not agree with the OAG's recommendation that the Commission use the OAG's zero-intercept proxy method for

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[172] *Id*., p. 2.
[173] *Id*.
[174] *Id*., pp. 2-3.
[175] *Id*., p. 3.
[176] *Id*.
[177] *Id*.

determining distribution costs in this rate case. The Department's specific concerns with the OAG's proposed zero-intercept method can be summarized as follows:

- The zero-intercept Proxy does not consider the cost of delivering power to the customer; and
- The zero-intercept proxy is not based on actual costs and therefore is not "grounded in reality."

The Department stated it agreed with the OAG's characterization that the CCOSS is largely dependent on the results of the minimum system analysis in this case. The Department also indicated that there is more than one way to conduct a minimum system study.[178]

The Department stated further that the minimum-size study is based on the actual equipment sizes and costs currently represented on Dakota Electric's system and therefore the minimum-size method is grounded in reality.[179]

The Department emphasized that neither the zero-intercept method nor the minimum-size method is superior to the other. The Department stated that both the zero-intercept and the minimum-size methods are appropriate minimum system methodologies for determining the customer portion and the demand portion of the utility's distribution costs.[180]

The Department stated that it agreed with the OAG that the zero-intercept methodology would more closely approximate a hypothetical zero-sized system than a minimum size methodology if "perfect" data were available. However, the Department stated that because "perfect" data is not available, the minimum-size method is used widely in CCOSS.[181]

The Department stated that the OAG's zero-intercept proxy method does not adequately reflect all of the costs of delivering power to customers. The Department stated that the cost of sizing the system to meet peak need is a capacity cost, in contrast to the costs of being able to deliver power to customers, which is a customer cost. In the opinion of the Department, total distribution costs includes costs of both of these functions and either a minimum-size study or a zero-intercept method will separate the costs of delivering power to customers from the cost of sizing the system to meet peak load.[182]

The Department agreed with the OAG that if load is considered in developing a minimum system study, some capacity costs can be classified as customer costs. The Department explained that because the minimum-size system study that DEA used is based on actual equipment on its system, there are demand costs associated with the real pieces of equipment that would not be accounted for in a zero-intercept model. Therefore the Department concluded that DEA could improve its minimum-size method by adding a capacity adjustment.[183]

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[178] Ex. 302, Ruzyki Rebuttal, p. 2
[179] *Id*., p. 4.
[180] *Id*., p. 5.
[181] *Id*., p. 4.
[182] *Id*., pp. 6-7.
[183] *Id*., pp. 5-6.

The Department stated its agreement with the NARUC Electric Manual that the minimum-size method has certain load-carrying capability that can be viewed as a demand related cost and therefore stated it would not object to a demand adjustment in DEA's next rate filing.[184]

The Department stated the demand adjustment would not be an easy adjustment to make and the minimum-size method, without this adjustment, yields slightly larger customer components than the zero-intercept method. However, because the customer charge is significantly below costs, the Department reasoned that this adjustment would not be expected to have a material effect in this rate case.[185]

DEA's Response to OAG

DEA stated that the OAG's zero-intercept proxy should be rejected.[186] DEA's concerns with the OAG's zero-intercept proxy method can be summarized as follows:

- The zero-intercept proxy method omits the system;
- The NARUC Electric manual does not indicate that the zero-intercept method constructs a minimum system devoid of material costs;
- The inflation adjustment that the OAG used in its zero-intercept proxy method is not reasonable, and
- The zero-intercept method is a dramatic change from both the minimum-size analysis DEA conducted used for this rate case and the zero-intercept analysis we used in the previous rate case.

In regard to the OAG's criticism of DEA's minimum system analysis, DEA continued to defend its choice for using the minimum-size method.

DEA stated that although it continues to believe that the zero-intercept method provides reliable results for classifying costs in the CCOSS, the main concern of the OAG regarding the number of data points remained from the last rate case. DEA explained that the data points used in the regression analysis represented the vast majority of plant in service for each account. Therefore, DEA stated it viewed the minimum-size method as the only viable option in this case.[187]

In response to the OAG's suggestion that DEA failed to include a demand adjustment in its minimum-size system study, DEA stated a demand adjustment was not needed or warranted. DEA based its conclusion on a weighted average benchmark comparison between its minimum-size system analysis in this case and the zero-intercept analysis from the last rate case.[188]

DEA explained that it provided a weighted average comparison of the minimum-size results with the zero-intercept results used in its last rate case and results were very similar. According to DEA, minimum-size method calculated a 61.5 percent weighted average of plant costs as

[184] *Id*., p. 7.
[185] *Id*., pp. 7-8.
[186] Ex. 126, Larson Rebuttal, p. 31.
[187] *Id*., p. 26.
[188] *Id*.

consumer costs compared to 57.1 percent weighted average of plant costs for the zero-intercept method used in its last rate case.[189]

DEA stated that the comparative results of DEA's methods are consistent with these NARUC Manual observations that "Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method …" and "…the differences may be relatively small."[190]

In addition, DEA claimed that a demand adjustment to account for the load carrying capacity of the minimum-size equipment only adds potential distortion to the plant classification process for DEA. DEA explained that the minimum-size analysis relied on the average book cost for each piece of plant and the average book cost reflects the cost of plant installed 30 to 40 years ago up to the present day. According to DEA, the minimum size plant could reflect an unusually low cost (if the majority of plant was installed years ago) or it could reflect an unusually high cost (if the majority of plant was installed more recently).[191]

DEA stated further that the description of the zero-intercept method in the NARUC Electric Manual does not indicate that the zero-intercept method constructs a minimum system devoid of material costs. According to DEA, the purpose of the zero-intercept method is to identify a hypothetical no-load situation, which is very different from a minimum system devoid of material costs.[192]

To illustrate the point that subtracting material costs from the installed costs is not equivalent to the zero-intercept method, DEA provided an example of transformers, which are part of DEA's distribution accounts subject to the minimum system analysis. According to DEA, all transformers include an enclosure that consists of material (sheet steel) and labor to fabricate the enclosure. In addition, DEA stated transformers have an internal structure on which components are mounted, insulating and cooling oil and insulating bushings. Finally, DEA stated that every transformer must be delivered to the utility. Therefore, DEA explained that transformers, and other distribution equipment, contain costs that are over and above the material costs alone.[193]

DEA described the OAG's alternative method as a "zero-system" analysis and stated the conceptual basis for the OAG's alternative method is flawed for the above reasons. According to DEA, a zero-intercept regression analysis described in the NARUC Electric Manual estimates the transformer installation costs and material cost of a theoretical zero capacity transformer. DEA stated that the OAG's zero-intercept proxy method ignores the minimum material cost and accordingly under-estimates the no-load cost of transformers and the other plant accounts subject to a minimum system analysis.[194]

DEA also objected to the OAG's inflation adjustments in its alternative method. DEA claimed it is not reasonable to make any adjustments based on an assumed average plant life. DEA

[189] *Id*., p. 23.
[190] *Id*.
[191] Ex. 127, Larson Surrebuttal, p. 13.
[192] *Id*., p. 20.
[193] *Id*., p. 28.
[194] *Id*.

explained that the Dakota Electric system was not uniformly constructed using the present plant and estimated the average age of the distribution system at 18 to 20 years after considerable review by its staff . DEA claimed that the OAG's inflation adjustment was arbitrary.[195]

Finally, DEA claimed that the OAG zero-intercept proxy method is a dramatic change from both the minimum-size analysis DEA conducted for this rate case and the zero-intercept analysis it used in the previous rate case.[196]

ALJ Report

The ALJ recommended that the Commission accept DEA's CCOSS, including the minimum-size system. Specifically, the ALJ recommended the following:

> 111. The Administrative Law Judge finds that DEA's minimum-size method for classifying distribution plant accounts is reasonably accurate, and reflects real-world minimum-size equipment needed to serve customer load on DEA's system. The Administrative Law Judge respectfully recommends that the Commission accept DEA's proposed CCOSS, including the minimum-size method.
>
> 112. In addition, the Administrative Law Judge recommends that the Commission require DEA to conduct its minimum system study in its next rate case by using the minimum-size method, supported by the zero-intercept method.
>
> 113. The Administrative Law Judge finds that there is insufficient evidence in the record to determine that a demand adjustment should be required in DEA's next rate proceeding, particularly if DEA performs its minimum system study using both the zero-intercept and the minimum-size methods of analysis. Therefore, the Administrative Law Judge does not recommend that the Commission require DEA to incorporate a demand adjustment into its next minimum-size method analysis.

Exceptions to the ALJ Report

The Department and DEA did not file exceptions to the ALJ's findings, conclusions or recommendations on its CCOSS.

In its Exceptions to the ALJ's Findings of Fact, Conclusions and Recommendations, the OAG recommended the Commission make significant modifications to findings 111 to 113 of the ALJ's Report, because OAG believes DEA's CCOSS relies on an inaccurate minimum system study.

The OAG stated it had demonstrated, through its testimony and briefing, that Dakota's minimum system analysis overestimated the customer cost portion of its distribution system because it

[195] *Id*., p. 29.
[196] *Id*., p. 31.

relies on the less accurate minimum-size method, and that it would be unreasonable to rely on DEA's study for revenue apportionment or rate design.

The OAG took exception to the ALJ's recommendation that the Commission should adopt Dakota's minimum system analysis. According to the OAG, by stating that DEA's minimum-size analysis "reflects real-world minimum-size equipment needed to serve customer load on DEA's system," the ALJ appears to have relied on the flawed premise that the minimum system should include some costs incurred to serve customer load.

The OAG explained this logic conflicts with both the explicit language of the NARUC Electric Manual, which states that costs incurred to serve load should be classified as demand costs, and the considerations used to classify other FERC accounts. The OAG argued that by including the cost of serving customer load in its minimum system, DEA's analysis overestimates the customer-cost portion of its distribution system.

Moreover, the OAG asserted that the ALJ appears to have been influenced by the fact that the OAG's recommendation was not based on a methodology specifically discussed in the NARUC Electric Manual.

The OAG argued that the zero-intercept analysis is the more accurate methodology described in the NARUC manual, but that conducting a proper zero-intercept analysis presents serious technical challenges. To support its recommendation, the OAG stated it had demonstrated mathematically that the zero-intercept proxy produces results that are equivalent to a zero-intercept analysis and the OAG's mathematical support was not disputed by any party. The OAG noted that the ALJ Report failed to mention the OAG's mathematical analysis and appears not to have considered it.

The OAG recommends the following modifications to the ALJ's report:

> 111. ~~The Administrative Law Judge finds that~~ DEA's minimum-size method for classifying distribution plant accounts is not reasonable and not accurate.~~, and reflects real-world minimum-size equipment needed to serve customer load on DEA's system. The Administrative Law Judge recommends that the Commission accept DEA's proposed CCOSS, including the minimum-size method.~~ The OAG has demonstrated that its zero-intercept proxy is the most accurate methodology in the record, is consistent-with the principles of cost-causation outlined in the-NARUC manual, and is mathematically sound. Therefore, DEA shall use the zero-intercept proxy recommended by the OAG in its CCOSS.
>
> ~~112. In addition, the Administrative Law Judge recommends that the Commission require DEA to conduct its minimum system study in its next rate case by using the minimum-size method, supported by the zero-intercept method.~~
>
> ~~113. The Administrative Law Judge finds that there is insufficient evidence in the record to determine that a demand adjustment should be required in DEA's next rate proceeding, particularly if DEA performs its minimum system~~

> ~~study using both the zero-intercept and the minimum-size methods of analysis. Therefore, the Administrative Law Judge does not recommend that the Commission require DEA to incorporate a demand adjustment into its next minimumsize method analysis.~~

Staff Analysis

According to the NARUC Electric Manual, when a utility installs distribution plant to provide service to a customer and to meet the individual customer's peak-demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying some distribution cost accounts are not as controversial as others. According to the NARUC Electric Manual, distribution substations costs (which include Accounts 360-Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related, because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served. Likewise, Accounts 369 – 373 (369-Service drops, 370-Meters, 371-Installations on Customer Premises, 372- Leased Property on Customer Premises, and 373- Street Lighting & Signal Systems) are normally classified as customer-related, because these costs normally vary with the number of customers.

The discussion of the merits of using a minimum-size system versus the zero-intercept classification method mainly affects the classification of costs in the major distribution-plant accounts for FERC Accounts 364 through 368 (364- Poles, Towers, and Fixtures, 365- Overhead Conductors and Devices, 366 & 367- Underground Conduits, Conductors, and Devices, and 368-Line Transformers), because these accounts involve both demand and customer costs.

On p. 90 of the NARUC Electric Manual it states the following:

> Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.
>
> …The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. …each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

The NARUC Electric Manual states that the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer and involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. According to the NARUC Electric Manual, the zero-intercept method seeks to identify the portion of plant related costs that can be identified with a hypothetical no-load or zero-intercept situation.

In comparing the two methods, the NARUC Electric Manual states on p. 95 the following:

> When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results…
>
> The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.
>
> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.
>
> When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.
>
> Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

Staff believes that the OAG has raised significant concerns regarding DEA’s minimum system study and believes that the OAG recommendation to use its zero-intercept proxy method as a minimum system analysis for DEA’s CCOSS warrants the Commission’s consideration.

Staff also suggests the Commission should be cautious on basing rate design decision on DEA’s CCOSS, because the minimum-size system study used by DEA did not include a demand adjustment. Based on the evidence presented in this case, Staff is not convinced that DEA’s CCOSS is reasonably accurate.

Although the size of a demand adjustment may be difficult to determine, the NARUC Electric

Manual is clear that the minimum size distribution equipment has load carrying capabilities, which will be classified as customer costs without a demand adjustment.

The NARUC Electric Manual also states that, in theory, the zero-intercept method more accurately classifies distribution costs between customer and demand than the minimum- size system method. While the Manual goes on the state that differences between the two methods "…*may* be relatively small" (emphasis added), evidence introduced by OAG in this rate case indicates the differences are, in fact, large and significant.

Both DEA and the Department agreed with the OAG and the NARUC Electric Manual that the zero-intercept method is an appropriate minimum system study that potentially could provide reliable results for classifying distribution costs. The Department stated that the zero-intercept methodology would more closely approximate a hypothetical zero-sized system than a minimum-size methodology if "perfect" data were availability.[197]

Likewise, DEA stated that it continues to believe that the zero-intercept method provides reliable results for classifying costs in the CCOSS. However, DEA also stated that the main concern of the OAG regarding the number of data points remained from the last rate case and that the data points used in the regression analysis in the last rate case represented the vast majority of plant in service for each account. As explained by the OAG, the zero-intercept model used by DEA in the last rate case had only three data points to determine the regression line and the zero-intercept to represent customer costs. Because of an inadequate number of data points, the OAG believed the zero-intercept method from the last rate case produced statistically unreliable results. For this reason, DEA stated it viewed the minimum-size method as the only viable option in this case.

It should also be noted that the zero-intercept method is based upon the assumption that the total installed unit costs of the distribution system varies on the size or capacity of the equipment. On pages 96-97 of the NARUC Electric Manual it states the following:

> Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation. Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. *Local area loads are the major factors in sizing distribution equipment.* (Emphasis added)

All parties are in agreement that, theoretically, the zero-intercept method more accurately identifies and separates customer costs from demand costs. Staff interprets the parties concerns

[197] The Department does not state what it means by "perfect" data. Staff assumes that the Department's statement is not a criticism of linear regression analysis or the zero-intercept method, but instead is reflective of DEA's use of only 3 data points for its zero-intercept method in the last rate case. In other words, Staff assumes, given the Department's endorsement of the zero-intercept method as a minimum system study, that by "perfect" the Department means adequate data to obtain a statistically significant linear regression result.

with using the zero-intercept method to be a concern with the limited availability of data for determining the regression line.[198]

The zero-intercept proxy method was introduced by the OAG as a means for determining the installation costs for each distribution account, because DEA lacked sufficient data to perform an adequate regression analysis. According to the OAG, it used the same data as DEA's minimum-size system (actual costs), but made some adjustments for inflation. While the zero-intercept proxy method was introduced by OAG as a third way, staff believes it may also be used as a means for estimating the demand adjustment that is necessary to remove demand-related cost, or the load carrying capability, from DEA's minimum-size study, precisely because it used the same data as DEA's minimum system study.

With the exception of the concern about the OAG's inflation adjustment, Staff notes that the Department and DEA's primary criticisms of the OAG's zero-intercept proxy method also apply to the theoretical zero-intercept method. However, both the Department and DEA support the theoretical zero-intercept method as an adequate method to be used as a minimum system study.

The Department stated that the zero-intercept proxy does not consider the cost of delivering power to the customer; and it implies that it is not based on actual costs and therefore is not "grounded in reality." In regard to the Department's latter concern, the OAG stated that the zero-intercept proxy is calculated by subtracting the material unit cost of the smallest size distribution equipment used for DEA's minimum-size method from the installed unit cost of the same sized distribution equipment to obtain the cost of installation. The zero-intercept proxy method is constructed using the same "actual" costs as are used for the construction of the minimum-size method, according to the OAG.

In regard to the Department's first concern, the zero-intercept proxy, similar to the zero-intercept method, determines the cost for the customer to connect to the distribution system (installation cost) and does not consider the cost of the distributions system ability to deliver capacity or load to the customer. The cost for delivering capacity or load to the customer in the zero-intercept proxy method, like the zero-intercept method, is considered to be a demand cost.

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[198] Linear regression analysis can be complicated analysis when judging the viability of the data and drawing conclusions on the relationship between the independent and dependent variables. However, the theoretical basis behind the zero-intercept is actually relatively simple and only requires basic algebra to interpret and understand. In this case, no parties appear to disagree on the theoretical interpretation of the model or the appropriateness of using the model for a minimum system analysis to classify distribution costs in the CCOSS.

In the model, $Y = a + bx$, the installed cost of the unit (Y) is the dependent variable that is determined by the right side of the equation. Basically, depending on the distribution account, (x) is the independent variable representative of costs for various sized poles, towers, conductors, conduit, transporters and/or other equipment. As described by the Department, when (x) is set to zero, (a) will represent the customer costs for each account that does not depend on the size or the capacity of the distribution system. The zero-intercept, or $Y = a$, is the cost for a customer to connect to a distribution system that has zero size and zero capacity.

Therefore, the zero-intercept method determines the cost for a customer to connect with the system. Because the size and capacity, (x), of the system is set to zero, the zero intercept model is referred to as a no-load system. A system without size or capacity has zero-load and the remaining cost, (a), can only be interpreted as the cost for the customer to connect to the system. As such, staff agrees with the OAG that the zero-intercept, (a), in this model is equivalent to the installation costs for the respective equipment.

The Department relied upon the NARUC Electric Manual's description of the minimum-size method to conclude that the customer portion of distribution costs should consider the costs to deliver power to the customer. The NARUC Electric Manual at page 90 states the following:

> Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer,' and service that is currently installed by the utility.

However, the description of the minimum-size method in the NARUC Electric Manual goes on to state that "[c]omparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method" and "…the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost."

As was described above, the zero-intercept method isolates the installation costs from the capacity (demand) costs by setting the capacity costs to zero. A minimum system study needs only to consider the cost for the customer to connect to the system; which, by definition, are the installation costs. All other components of the distribution costs are considered demand costs according to minimum system theory, as described in the NARUC Electric Manual.

In regard to DEA's stated concern that the zero-intercept proxy method omits the system, the intention of both the zero-intercept method and the zero-intercept proxy method is to separate system costs from the costs for the customer to connect to the system (installation costs). There is no system in either method, and that is the point of separating the customer costs from the demand costs in the distribution accounts 364-368, according to the NARUC Electric Manual.

In regard to the second concern, DEA provided an example of a transformer to demonstrate that transformers contain more than material costs. Staff found this to be a curious example that bears no relevance on whether the zero-intercept proxy method is able to separate customer costs from demand costs in the distribution accounts. DEA stated that transformers includes costs that consist of material (sheet steel, insulation, cooling oil, bushings and other components) and labor to fabricate an enclosure and to mount the components. In addition, DEA stated that every transformer must be delivered to the utility. DEA's point is that transformers contain material, assembly and delivery costs that are included in the total installed costs of the equipment.

Staff notes that the same thing can be said for every consumer and capital good purchased in the market. Every good contains a cost component of material, labor (for assembly) and delivery. In economic theory, this process is referred to as value-added. However, in neither the zero-intercept nor the zero-intercept proxy method is the intention of the methodology to separate material, assembly, delivery and installation costs of a transformer from each other. Rather, the intention of both the zero-intercept method and the zero-intercept proxy method is to separate the installation (customer) costs from the demand costs. In both methods, the demand costs represent the system. In the case for transformers, the material costs for the transformers include assembly of the transporter and the delivery of the transformer to the utility.[199]

Staff also makes the following point. In the regression equation, $Y = a + bx$, if we set the size of the transformer or equipment, (x), to zero to create a no-load system with zero demand, then there would be no assembly of components (zero-labor) to make a zero-sized transformer and there would be no delivery charge for delivering the zero-sized transformer to the utility.

Staff believes that the zero-intercept proxy method provides a reasonable alternative to use in place of a zero-intercept method, when adequate data for determining a linear regression for each distribution account is not available. Although the OAG has not provided examples for previous uses of the zero-intercept proxy method in other CCOSS, the OAG has provided a clear and logical process, which relied on realistic assumptions, to build a theoretical minimum system based on the theoretical basis for the zero-intercept method that is described in the NARUC Electric Manual. With the exception of DEA's concern for the OAG's inflation adjustment, Staff does not believe that any other concern the Department or DEA had for the OAG's zero-intercept proxy method would not also apply to zero-intercept method in the NARUC Electric Manual.

In regard to the inflation adjustment, the Commission may wish to consider other inflation adjustments or DEA's position that no inflation adjustment is necessary to the zero-intercept proxy method. If the Commission did choose to use another inflation adjustment, or no inflation adjustment, then it would need to require DEA to submit a filing for the zero-intercept proxy method with the new inflation adjustment and apply it to its CCOSS.

Staff recommends that without a demand adjustment to DEA's minimum system study, the Commission should be cautious about basing rate design decisions on DEA's proposed CCOSS. The Commission may wish to rely more upon non-cost factors when choosing between rate design alternatives.

Decision Alternatives - CCOSS

(Note: The following decision alternatives correspond to 9:A-G in the Deliberation Outline, pp. 7-8.)

Class Cost of Service Study in this rate case:

A. Approve DEA's proposed CCOSS, and its use of the minimum-sized system study. (DEA, Department & ALJ) **or**

B. Approve the use of OAG's zero-intercept proxy method in DEA's CCOSS, instead of DEA's minimum-size system study, **and**

   Amend the ALJ Report (i.e. finding 111) as recommended by the OAG.

[199] If this were not the case, and DEA maintained a separate account for assembly of equipment and the delivery of equipment to the utility, then these costs should also be subtracted from the total installed cost of the equipment, which would reduce further the cost for customers to connect to the system (installation costs).

111. ~~The Administrative Law Judge finds that~~ DEA's minimum-size method for classifying distribution plant accounts is <u>not</u> reasonable and <u>not</u> accurate<u>.</u>~~, and reflects real-world minimum-size equipment needed to serve customer load on DEA's system. The Administrative Law Judge recommends that the Commission accept DEA's proposed CCOSS, including the minimum-size method.~~ <u>The OAG has demonstrated that its zero-intercept proxy is the most accurate methodology in the record, is consistent-with the principles of cost-causation outlined in the-NARUC manual, and is mathematically sound. Therefore, DEA shall use the zero-intercept proxy recommended by the OAG in its CCOSS</u>. (OAG) <u>**or**</u>

C. Approve the use of OAG's zero-intercept proxy method in DEA's CCOSS, instead of DEA's minimum-size system study; however, require the use of a different inflation adjustment. Amend the ALJ's report as necessary. (Staff)

Class Cost of Service Study in DEA's next rate case:

D. Adopt the recommendations in ALJ findings 112 and 113:

112. In addition, the Administrative Law Judge recommends that the Commission require DEA to conduct its minimum system study in its next rate case by using the minimum-size method, supported by the zero-intercept method.

113. The Administrative Law Judge finds that there is insufficient evidence in the record to determine that a demand adjustment should be required in DEA's next rate proceeding, particularly if DEA performs its minimum system study using both the zero-intercept and the minimum-size methods of analysis. Therefore, the Administrative Law Judge does not recommend that the Commission require DEA to incorporate a demand adjustment into its next minimum-size method analysis. (DEA, Department, and ALJ) <u>**or**</u>

E. Do not adopt the ALJ's recommendation and strike findings 112 and 113. (OAG) <u>**or**</u>

F. Do not adopt the ALJ's recommendation, strike ALJ findings 112 and 113, and require DEA to use a demand adjustment to its minimum-size study in its next rate case. (Staff) <u>**or**</u>

G. Do not adopt the ALJ's recommendation, strike ALJ findings 112 and 113, and require DEA to use the OAG's zero-intercept proxy method as a means for estimating the demand adjustment to its minimum-size method in its next rate case. (Staff)

Rate Design

PUC Staff: Andy Bahn

Introduction

The ALJ in this case stated that rate design is the second step of the two-step rate making process where government regulation of utilities' rates approximates the results that would be achieved in a competitive environment. The ALJ explained that in the first step, the Commission determines the revenue requirement, which is a quasi-judicial and fact intensive process. The ALJ stated that the second step, which designs the structure that will determine the rates charged to customers, is largely a quasi-legislative function. According to the ALJ, while the second step of rate making largely involves facts, it also involves policy decisions.[200]

The ALJ stated that she relied on the following Minnesota Statutes as guidelines for analyzing rate design proposals:[201]

- Minn. Stat. § 216B.16, Subd. 4, states that the burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change.

- Minn. Stat. § 216B.16, Subd. 15 states that the commission must consider ability to pay as a factor in setting utility rates

- Minn. Stat. § 216B.03 states that every rate made, demanded, or received by any public utility, shall be just and reasonable. In addition, rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers. And, to the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use and the goals set forth in Minn. Stat. § 216C.05. Finally, any doubt as to reasonableness should be resolved in favor of the consumer.

- Minn. Stat. § 216C.05 states that there is a vital interest in providing for: increased efficiency in energy consumption, the development and use of renewable energy resources wherever possible. In addition, it is in the public interest to review, analyze, and encourage those energy programs that will minimize the need for annual increases in fossil fuel consumption by 1990 and the need for additional electrical generating plants, and provide for an optimum combination of energy sources and energy conservation consistent with environmental protection and the protection of citizens. This assumes energy policy planning and implementation leading to the transition from historic growth in energy demand to a period when demand for traditional fuels becomes stable and the supply of renewable energy resources is readily available and adequately utilized. Furthermore, it is in the public interest to encourage those energy programs that will provide an optimum combination of energy resources, including energy savings. Finally, such programs should lead to progress toward greater reliance on cost-effective energy

[200] OAH, *Findings of Fact, Conclusions of Law and Recommendations,* March 2, 2015, ¶ 114, p. 27.
[201] *Id.*, ¶¶ 115-118, pp. 127-28.

efficiency and renewable energy and lesser dependence on fossil fuels in order to reduce the economic burden of fuel imports, diversify utility-owned and consumer-owned energy resources, reduce utility costs for businesses and residents, improve the competitiveness and profitability of Minnesota businesses, create more energy-related jobs that contribute to the Minnesota economy, and reduce pollution and emissions that cause climate change.

- Minn. Stat. § 216B.07 states that no public utility shall, as to rates or service, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage.

In addition, the ALJ stated that the Commission has relied on the following principles in designing reasonable and just rates:[202]

- Rates should be designed to allow the utility a reasonable opportunity to recover its revenue requirement, including the cost of capital;

- Rates should promote efficient use of resources by sending appropriate price signals to customers, reflecting the costs of serving them. For example, an appropriate price signal encourages conservation by customers;

- Rate changes should be gradual so as to limit rate shock to consumers. Rate stability and continuity are important to both the utility and the consumer; and

- Rates should be understandable and easy to administer. Maintaining ease in administration helps ensure that customers understand their utility bills better.

Apportionment of Class Revenue Responsibility

PUC Staff: Andy Bahn

Statement of the Issue

Should the Commission approve the apportionment of class revenue responsibility set forth in the Settlement Agreement between DEA and the Department?

Position of the Parties

Revenue Apportionment agreed upon by DEA and the Department

DEA 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. DEA's initial proposed revenue apportionment would

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[202] *Id.*, ¶ 115, p. 128.

increase the Residential & Farm Service class by 2.77%, the Small General Service class by 5.08%, and the General Service class by 0.6%.[203]

The Department agreed with DEA's proposed revenue apportionment, with two exceptions. In its direct testimony, the Department recommended providing more relief to the Small General Service class by increasing the revenues from General Service, and using those revenues to further mitigate the increase to the Small General Service class. The Department explained that while the increase to the General Service class moves the class slightly further from cost, the revenues would remain less than 1% above the cost of service (100.7%), and represent an increase of only 0.34% over current revenues compared with the 0.04% increase proposed by DEA. The Department stated that the slightly higher increase to the General Service customers would allow the increase to the Small General Service class to be held to 3%, which would be a more moderate increase than the 5.15% proposed by DEA.[204]

In rebuttal testimony, DEA raised the concern that the Department's initial apportionment of revenue responsibility to the Small General Service class did not change the class relationship to cost significantly from the outcome of DEA's previous rate case. DEA stated that in its last general rate case (Docket No. E-111/GR-09-175), the cost of service study indicated a revenue deficiency of about 14% for Small General Service and the revenue increase approved for Small General Service in that case was about 9.6%, which was about 4.4% less than the cost of providing service.[205]

In this case, DEA stated its CCOSS identified a revenue deficiency of 7.47% for Small General Service and based on the CCOSS results, among other factors, DEA proposed an increase of 5.15% for Small General Service, which leaves a revenue deficiency of about 2.3 percent according to its CCOSS.[206]

According to DEA, the Department's recommended revenue increase of 3% for Small General Service leaves a continuing revenue deficiency of about 4.5% compared to the cost of providing service, which is nearly the same revenue deficiency carried forward from the previous general rate case. DEA stated its proposed revenue increase for Small General Service reduces the continuing revenue deficiency from this class by about half, which would help move this class's rates closer to its cost of service.[207]

The Department stated it recognized that its initial recommendation for the Small General Service class did not change the class relationship to cost significantly from the outcome of the previous rate case. In response to DEA's concerns, the Department reviewed its recommended apportionment, and concluded there was room to move the Small General Service class closer to cost. The Department recommended revenues apportioned to the Small General Service class increase from 3.0 to 3.5 percent. The Department maintained this apportionment would not unreasonably burden other classes and the Small General Service class would be approximately 3.7 percent below the cost of service compared with 4.1 percent in the Department's original

[203] Ex. 101, Larson Direct, pp. 39-40.
[204] Ex. 304, Peirce Direct, p. 7.
[205] Ex. 126, Larson Rebuttal, p. 8.
[206] *Id*.
[207] *Id*.

recommendation. In addition, the Department recommended a slight increase in the revenue responsibility for General Service class customers, to a 0.27 percent increase.[208]

DEA agreed with the Department on these revenue apportionments for the Small General Service and General Service classes in the January 18, 2015 Settlement Agreement.[209]

OAG

The OAG stated that DEA's revenue apportionment does not appropriately balance rate design principles and disproportionately places DEA's revenue increase upon the residential and farm and small general service classes. The OAG stated it is unreasonable to weigh the CCOSS as heavily as DEA did for its rate design recommendations, because CCOSSs are inherently unreliable. According to the OAG, DEA's proposed CCOSS incorrectly classified the costs associated with the distribution system, which overstated customer costs and biased cost allocation against the residential and farm class. [210]

The OAG offered an alternative revenue apportionment that it stated was relatively close to the overall rate increase. The stated objective was to balance rate design principles to maximize the economic principle of social welfare. The factors the OAG considered for meeting its objective were its zero-intercept proxy CCOSS, minimization of rate shock, and concerns that rate increases be as smooth and predictable as possible between rate cases. In addition, the OAG stated it tempered the increase for the Small General Service class because DEA's original proposal increased that class significantly more than other classes.[211]

The OAG's proposed revenue apportionment as compared to the Settlement Agreement is given below in the following table:[212]

	Total System	**Residential and Farm**	**Small General Service**	**Irrigation**	**General Service**	**C&I Interrupt**	**Lighting**
Settlement Agreement	2.11%	2.79%	3.5%	2.00%	0.27%	2.25%	1.02%
OAG's Apportionment of DEA's Rate Increase	2.11%	1.90%	2.61%	2.80%	1.91%	3.41%	1.50%

(Note: The percentages in this table are based on DEA's initial request for a $4.189 million or approximately 2.1% rate increase.)

[208] Ex. 305, Peirce Surrebuttal, pp. 3-4.
[209] Ex. 128, Settlement Agreement, p. 13.
[210] Ex. 200, Nelson Direct, p. 31.
[211] *Id*., pp. 31-32.
[212] *Id*. And, Ex. 128, Settlement Agreement, p. 13.

ALJ Report

The ALJ Report found that the revenue apportionment agreed to by the Department and DEA was just and reasonable and therefore recommended that the Commission approve the revenue apportionment as set forth in the Settlement Agreement. Specifically, the ALJ Report reached the following conclusions in regard to revenue apportionment:[213]

> 129. The Administrative Law Judge finds that the OAG's proposed revenue apportionment is based in part on its CCOSS, which in turn utilized the zero-intercept proxy method. Because the record does not support the use or the results of the zero-intercept proxy method, the OAG's CCOSS, and its revenue apportionment which incorporated its CCOSS, are not reliable.
>
> 130. In addition, the Administrative Law Judge finds that by over-emphasizing the principle of balancing the revenue increases among classes, the OAG under-emphasized the importance of basing rate design on cost. For example, based on DEA's CCOSS, General Service class customers already pay more than 100 percent of their costs. The OAG's proposed revenue apportionment would place a significantly higher burden on General Service customers, significantly increasing inter-class subsidies.
>
> 131. The Administrative Law Judge finds that the revenue apportionment proposed in the Settlement Agreement imposes a more reasonable increase on General Service class customers in relation to their costs, while assigning a 2.79 percent increase to Residential and Farm class customers - a percentage that cannot reasonably be presumed to constitute rate shock, but will still bring this class closer to paying its costs.
>
> 132. The Administrative Law Judge finds that the revenue apportionment agreed to by DEA and the Department, as reflected in the Settlement Agreement, is just and reasonable and supported by the record. Therefore, the Administrative Law Judge respectfully recommends that the Commission adopt the revenue apportionment as set forth in the Settlement Agreement.

Exceptions to the ALJ Report

The Department and DEA did not file exceptions to the ALJ's findings, conclusions or recommendations on revenue apportionment.

In its Exceptions to the ALJ's Findings of Fact, Conclusions and Recommendations, the OAG recommended the Commission make significant modifications to findings 129 to 132 of the ALJ Report, because the ALJ recommended revenue apportionment is based on DEA's flawed CCOSS.

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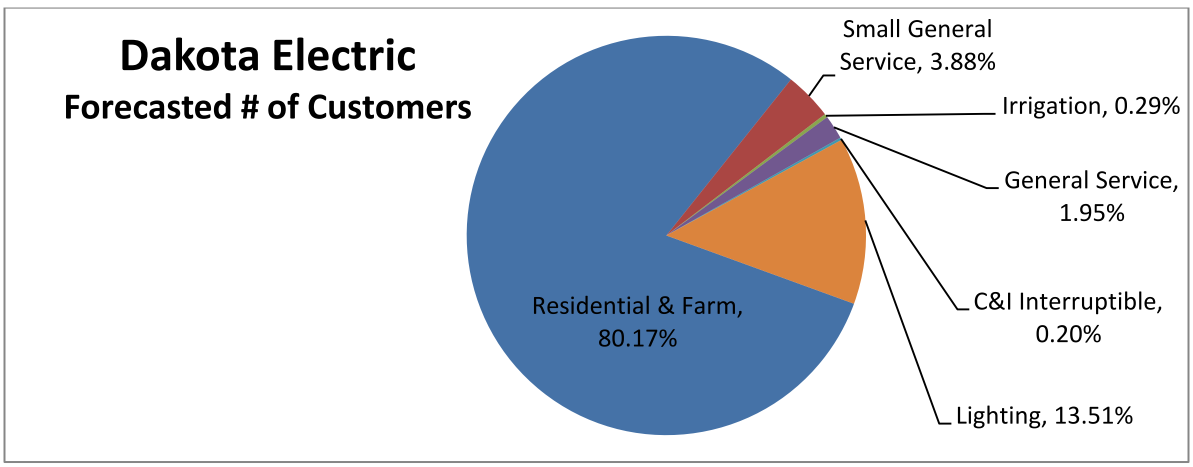
[213] OAH, *Findings of Fact, Conclusions of Law and Recommendations,* March 2, 2015, ¶¶ 129-132, p. 31.

The OAG stated that the ALJ rejected the OAG's proposed revenue apportionment after finding that it "is based in part on [the OAG's] CCOSS" that the ALJ rejected. The OAG asserted this Finding should be modified because the OAG's CCOSS produces more accurate results than DEA's CCOSS. The OAG stated its recommended revenue apportionment is reasonable, and requires all customer classes to make a meaningful contribution to DEA's supposed increased cost of service. The OAG recommends removing Findings 129 through 132 from ALJ's Report and replacing them with the following:

> 129. The OAG's proposed revenue apportionment is reasonable. The OAG's proposed revenue apportionment is informed by the OAG's CCOSS, which provides the most accurate assessment of customer costs. In addition, the OAG's revenue apportionment requires each customer class to make meaningful contributions to Dakota's cost of providing utility service, while not over-burdening any single customer class.

Staff Analysis

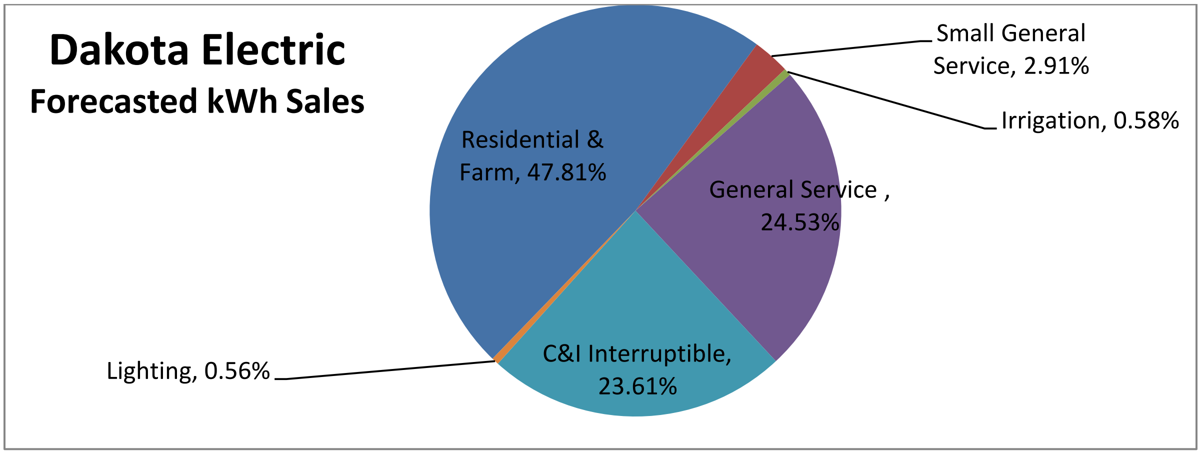
Approximately 80% of Dakota Electric's customers are Residential & Farm customers,[214] 2% are General Service customers,[215] and 0.20% of customers are Commercial and Industrial (C&I).[216] General Service (i.e. C&I Firm) and C&I interruptible customers each account for nearly one fourth of Dakota's forecasted sales in kWh and Residential and Farms service customers account for a little less than one half of Dakota's forecasted sales in kWh.



[214] Residential and Farm customers consist of three separate rate schedules: (1) Schedule 31, the largest rate class with 95,586 customers forecasted for 2014 is Residential & Farm Service that is available to individual residential and farm members for all domestic and farm use, except irrigation; (2) Schedule 32, Residential & Farm Demand Control that is available to residential and farm members with at least 5 kW of controlled electric heating units (18 forecasted customers in 2014); and (3) Schedule 53, Residential and Farm Service with Time-of-Day Rate (19 forecasted customers in 2014).

[215] General Service customers consist of two rate schedules: (1) Schedule 46 General Service that is available to any commercial member for all uses except irrigation (2316 forecasted customers in 2014), and (2) schedule 54, General Service Time of Use rate (8 forecasted customers in 2014).

[216] C&I Interruptible consist of two rate schedules that are available to any member with a minimum controllable demand of 50 kW: (1) Schedule 70, Full Interruptible Service (211 forecasted customer in 2014), and (2) Schedule 72, Partial Interruptible Service (28 forecasted customers in 2014).



Dakota Electric forecasted 95,623 Residential & Farm customers, 2,324 General Service customers and 239 C&I Interruptible for the 2014 test year. In addition, Dakota forecasted 4,630 Small Service Customers.[217] Dakota forecasted Residential & Farm customers will account for approximately 880 million kWh, General Service customers approximately 450 million kWh, C&I Interruptible customers approximately 435 million kWh and Small General Service customers approximately 50 million kWh sales in 2014.

The following table contains DEA's final revenue apportionment of each customer class' responsibility for DEA's revenue requirements under current and proposed rates based on the ALJ's final recommendations. [218]

Proposed Revenue Apportionment

(Note: The dollar amounts and percentages in the following table are based on the ALJ's recommended rate increase, modified to correct for the error in the ALJ's wage adjustment, which is approximately $3.767 million or 1.89%.)

Rate Class (Schedules)	Current Revenue ($)	DEA & Department Settlement Proposal ($)	Final Proposed Revenue ($)	Proposed Increase	
				($)	(%)
Res & Farm (31,32,53)	$113,411,078	$116,548,827	$116,284,715	$2,873,637	2.53%
Small Gen Service (41)	$6,767,752	$7,004,438	$6,984,275	$216,523	3.20%

[217] Small General Service customers are defined as any commercial member for all uses, except irrigation pumps, where the metered demand is 15 kW or less.
[218] The tables and graphs are based on DEA Compliance Filing, March 9, 2015, p. 15-20..

Rate Class (Schedules)	Current Revenue ($)	DEA & Department Settlement Proposal ($)	Final Proposed Revenue ($)	Proposed Increase	
				($)	(%)
Irrigation (36)[219]	$973,785	$993,287	$991,436	$17,651	1.81%
Gen Service (46, 54)	$47,740,345	$47,491,372	$47,817,125	$76,780	0.16%
C & I Interruptible (70, 71)	$26,501,221	$27,100,366	$27,046,584	$545,363	2.06%
Lighting (44, 44-1, 44-2, 44-3)	$1,992,119	$2,012,432	$2,007,968	$15,848	0.80%
Mun. Sirens (47)	$3,900	$3,900	$3,900	$0	0.00%
Low Watt Unmeter (45)[220]	$5,184	$6,480	$6,480	$1,296	25.00%
Elec. Veh. (33)[221]	$1,037	$990	$990	($47)	-4.53%
Geo. Heat Pump (49)[222]	$32,921	$36,406	$36,406	$3,485	10.59%
Cnt. Nrg. Stor. (52)[223]	$404,057	$419,307	$419,307	$15,250	3.77%
Cnt. Interrup (52)[224]	$2,481,912	$2,575,568	$2,575,568	$93,656	3.77%

[219] Irrigation service consists of both firm and interruptible service that is available to any member for service to irrigation pumps.

[220] Available for low-wattage electronic devices that are: 1) Individually located at each point of delivery, 2) Rated at less than 150 watts, and 3) A determinable load level.

[221] Available on voluntary basis as a pilot program for residential consumers taking service under Schedule 31 who also desire metered service for the sole purpose of electrically charging a licensed automobile or light truck.

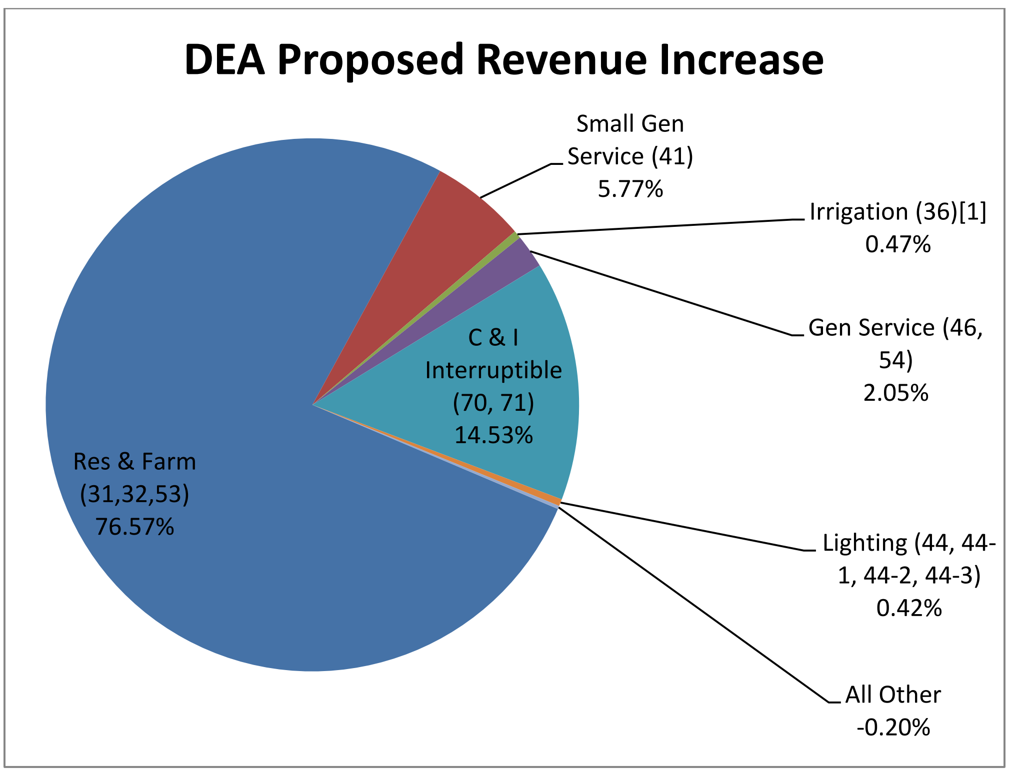
[222] Available to any commercial member for energy used by a geothermal heat pump system

[223] Controlled Energy Storage is available to members taking service concurrently under another rate schedule. This rate is for interruptible service to energy storage loads which are remotely controlled by the Association.

[224] Controllable interruptible Service is available to member taking service concurrently under another rate schedule. This rate is for interruptible service to qualifying loads which are remotely controlled by the Association.

Rate Class (Schedules)	Current Revenue ($)	DEA & Department Settlement Proposal ($)	Final Proposed Revenue ($)	Proposed Increase	
				($)	(%)
Standby Ser. (60)[225]	$56,550	$60,990	$60,990	$4,440	7.85%
Cycle Air Cond. (80)[226]	($1,539,168)	($1,664,599)	($1,664,599)	($125,431)	8.15%
Well Spring	$39,427	$39,427	$39,427	$0	0.00%
Total Retail	**$198,872,121**	**$203,014,236**	**$202,610,572**	**$3,738,451**	**1.88%**

If the proposed revenue apportionment as set forth in the Settlement Agreement, and as recommended by the ALJ Report, is approved in its entirety, Residential & Farm customers would be responsible for nearly 77% of the proposed revenue increases. Small General Services would be responsible for approximately 6%, General Services 2% and C&I Interruptible 15% of the total proposed revenue increases. Dakota's proposed revenue increases are apportioned among the customer classes as follows:



225 Standby service is for the quantity specified in the member's Electric Service Agreement as the maximum amount of firm or non-firm standby service the Cooperative is obligated to supply.
226 Cycled Air Conditioning Service is available to members taking service concurrently under another rate schedule. This rate is for interruptible service to central air conditioners which are remotely controlled by the Association.

The Percentage increase for the alternative revenue apportionment recommended by the OAG compared with the final revenue apportionment based on the ALJ recommendations (modified to correct the error in the ALJ's wage adjustment) is the following:

	Total System	Residential and Farm	Small General Service	Irrigation	General Service	C&I Interrupt	Lighting
Settlement Agreement	1.88%	2.53%	3.5%	3.20%	0.16%	2.06%	0.80%
OAG's Apportionment of DEA's Rate Increase	1.88%	1.90%	2.61%	2.80%	1.91%	3.41%	1.50%

Minn. Stat. § 216B.16, Subd. 4, states that the burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change. Staff shares the OAG's concern that a revenue apportionment based upon DEA's CCOSS may not have met this burden of proof. Staff agrees with the OAG that it may be unreasonable to base rate design recommendations on DEA's CCOSS, because DEA's CCOSS does not appear to be reliable. As described above, DEA's CCOSS does not include a demand adjustment, and therefore disproportionately places DEA's revenue increase upon the Residential and Farm and the Small General Service classes.

As described in the CCOSS section of the briefing papers, Staff believes the record in this case supports the Commission's consideration of OAG's proposed alternative zero-intercept proxy method as a reasonable alternative to the zero-intercept method, given the inadequate number of data points DEA has confirmed it has for the creation of a reliable regression analysis. Likewise, Staff is concerned that DEA's minimum-sized method may not be a reasonable minimum system study, because it does not include a demand adjustment.

In addition, as described above, Staff believes that the record in this case supports that the minimum system study can have a significant impact on the CCOSS as demonstrated by the OAG's analysis. Therefore, Staff suggests that the Commission may wish to consider whether DEA has met its burden of proof for its revenue apportionment proposal based on its CCOSS, which used the minimum-sized study to classify costs between customer and demand costs and did not include a demand adjustment.

Decision Alternatives – Revenue Apportionment

(Note: The following decision alternatives correspond to 10:A-C in the Deliberation Outline, p. 8.)

A. Approve the apportionment of class revenue responsibility as set forth in the Settlement Agreement. (DEA, Department & ALJ) **or**

B. Approve the apportionment of class revenue responsibility recommended by the OAG; **and**

Amend the ALJ Report (i.e. findings 129 through 132) by replacing finding 129 with the following and striking findings 130, 131, and 132.

> 129. The OAG's proposed revenue apportionment is reasonable. The OAG's proposed revenue apportionment is informed by the OAG's CCOSS, which provides the most accurate assessment of customer costs. In addition, the OAG's revenue apportionment requires each customer class to make meaningful contributions to Dakota's cost of providing utility service, while not over-burdening any single customer class. (OAG) **or**

C. Do not approve the revenue apportionment as set forth in the Settlement Agreement or any revenue apportionment based upon DEA's CCOSS; instead, increase all customer classes by the same percent as the percentage of the overall rate increase. (Staff)

Monthly Fixed Customer Charges

PUC Staff: Andy Bahn

Statement of the Issue

Should the Commission approve the monthly fixed customer charges agreed to in the Settlement Agreement between DEA and the Department, and as modified in the ALJ Report?

Position of Parties

Customer Charges Agreed Upon by DEA and the Department

DEA stated that its proposed increase in the monthly fixed charge for its customer classes will accomplish the following objectives:[227]

i. Provide a more appropriate recovery of costs through monthly fixed rates;

ii. Reduce the amount of revenue recovered through volumetric rates;

iii. Align with similar rates the Commission has approved for neighboring utilities; and

iv. Makes reasonable progress toward aligning fixed monthly charges with customer costs in this rate case.

DEA stated that not all "customer" related costs allocated to each class in the CCOSS are appropriate for recovery in the monthly fixed charge. DEA stated it believes it is appropriate for the monthly fixed charge to recover costs it incurs to stand ready to provide electric service, excluding costs for primary line. The monthly fixed costs DEA identified for recovery in this analysis are as follows:[228]

Residential	$11.65
Small General	$18.94
Irrigation	$44.09
General	$51.24
C&I Interruptible	$167.66

DEA noted that a smaller increase in the monthly fixed charge could result in taking 20 years or more to reach the appropriate cost recovery level for customer costs, according to DEA's CCOSS, based on a five-year cycle for Dakota Electric rate cases.[229]

[227] Ex. 101, Larson Direct, pp. 41.
[228] *Id.*, p.33.
[229] *Id.*, p.41.

DEA stated that its CCOSS showed a required revenue increase from Residential & Farm members of about 2.85 percent. Accordingly, DEA initially recommended that the monthly fixed charge be increased from $8.00 to $10.00 for Residential Members.[230]

Similarly, DEA stated its CCOSS study showed a required revenue increase from Residential & Farm Demand Control members and Residential & Farm Time of Day of about 2.85 percent. Accordingly, DEA recommended that the monthly fixed charge for both of these classes be increased from $11.00 to $13.00.[231]

Likewise, DEA stated that its CCOSS showed the need to increase revenues from the Small General Service class in the amount of $497,000 or 7.47 percent, therefore DEA proposed an overall revenue increase accomplished by increasing the monthly fixed charge for Small General Service from the present $10.00 per month to $14.00 per month.[232]

DEA stated that it proposed to increase the monthly fixed charge for residential service and small general service such that it may attain the desired customer cost level (based on its current CCOSS) in two steps – one step in this rate case and another step in its next rate case.[233]

For the other customer classes, DEA proposed increasing the monthly fixed charge by a percentage similar to the residential monthly fixed charge increase.[234]

DEA stated that its CCOSS showed a slight decrease of about 0.33 percent is justified for the General Service rate schedule, and DEA proposed a slight increase in revenue from this rate schedule. The present General Service Schedule 46 includes a monthly fixed charge of $28.00, which DEA proposed to increase to $34.00.[235]

Dakota Electric proposed to realign component rates for General Service Time of Day members to track changes to other similar rate schedules. Therefore, DEA proposed to increase the monthly fixed charge for General Service Time of Day from the present $30.00 to $36.00.[236]

DEA stated its CCOSS showed the need to increase revenues from irrigation service $19,783 or about 2.03%. The firm service irrigation rate structure presently includes a monthly fixed charge of $24.00 and DEA proposed to increase this monthly fixed charge to $30.00 per month.[237]

In addition, DEA stated its CCOSS showed a need to increase revenue from the C&I interruptible members by about 2.33 percent and to accomplish this revenue increase, DEA proposed to increase the monthly fixed customer charge from $80.00 to $110.00 per month.[238]

[230] *Id*.
[231] *Id*., pp. 42 & 51.
[232] *Id*., p. 45.
[233] *Id*., p. 40.
[234] *Id*., pp. 40-41.
[235] *Id*., p. 45.
[236] *Id*., p. 51.
[237] *Id*., p. 43.
[238] *Id*., p. 53.

The Department stated that, as a policy matter, it important to move the monthly customer charge closer to cost, because the price signals sent to customers should reflect the cost of serving them, including the fixed cost of providing service whether or not they use any electricity.[239]

The Department recommended approval of DEA's proposed monthly fixed charges, with the exception of the Residential & Farm members. The Department recommended the Residential & Farm monthly fixed charge be increased by $1.00 per month rather than the $2.00 increase proposed by DEA.[240] The Department recommended a more modest increase in the Residential & Farm fixed monthly charge to begin the process of moving those customers towards cost.[241]

The Department based its recommendation to increase the monthly fixed charge on DEA's CCOSS, which indicates the customer classes have customer charges set below the monthly fixed costs of serving a customer. The Department indicated that to the extent customer costs are not being recovered through the monthly customer charge they will be recovered from energy charges paid by all customers within a class. According to the Department, if a customer's total usage and customer charge payments are insufficient to recover the cost of serving an individual customer, the remaining customer costs are recovered through the usage charges paid by customers with higher levels of usage. The Department concluded from this reasoning that customers who use more energy would pay for costs they do not impose on the system.[242]

According to the Department, overpayments by high usage customers subsidize other customers within the same class who pay less than the cost to serve them. The Department termed such outcomes intra-class subsidies and stated that these subsidies should be minimized.[243] The Department stated that customers who use larger amounts of energy would pay lower bills if customer charges were set closer to costs, because these customers would not have to pay the subsidy in their energy charge to offset the customer costs that low-use customers impose on the system for which they do not pay.[244]

The Department stated that requiring high usage customers to pay for customer-related costs that they do not impose on the system while allowing other customers to avoid paying for the costs they impose on the system could lead to either under-recovery or over-recovery of customer-related costs. The DOC stated it strongly recommended that the Commission provide appropriate price information by adopting rates that are based on cost, to the extent possible.[245]

In addition, the Department stated that because some customers with higher usage levels may be low-income customers, an increase in the customer charge would limit the consequences of a rate increase on low-income, higher-usage customers.[246]

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[239] Ex. 305, Peirce Surrebuttal, p. 8.
[240] Ex. 304, Peirce Direct, p. 10.
[241] *Id*., p. 11.
[242] *Id*., pp. 10-11.
[243] *Id*., p. 11.
[244] *Id*., p. 12.
[245] *Id*., pp. 12-13.
[246] *Id*.

Finally, the Department stated that an increase in the residential customer charge to $9.00 appears reasonable because it compares favorably with the fixed monthly charges of other electric utilities' customers.[247]

Although the Department agreed that charging a higher energy rate encourages customers to use less energy, the Department stated that taken to its logical end, recovering all customer costs through the energy charge would tell DEA's customer-members that there is no cost of being connected to DEA's system. According to the Department that would be inaccurate information and it would send an inappropriate price signal.[248]

In addition, the Department stated that DEA's rate design already promotes energy conservation, since customer bills contain a demand and an energy component, in addition to the fixed monthly charge. According to the Department, this rate design directly promotes energy conservation since customers can decrease their bills by using less energy.[249]

In addition, the Department noted that DEA offers energy conservation programs, in conjunction with its wholesale provider Great River Energy (GRE), including rebates, that encourages its members to use less energy. The costs of DEA's energy conservation programs are included in DEA's energy charge, thus sending an additional signal to its members to use less energy.[250]

The Department conducted an analysis to estimate the amount of electricity use necessary to recover the remaining customer costs through the energy charge. The Department stated that according to DEA's CCOSS, the residential customer cost is $23.39 per customer per month, compared with the current customer charge of $8.00 per month. The Department stated that the $15.39 difference between the monthly customer cost and the amount of the customer charge applied to those customer costs must be (and is) recovered through the energy charge.

As part of the Settlement Agreement, DEA and the Department agreed on the Department's proposed Residential and Farm fixed monthly customer charges.[251]

[247] *Id*., p. 11.
[248] *Id*., p. 13.
[249] *Id*.
[250] *Id*., pp. 13-14.
[251] Ex. 128, Settlement Agreement, p. 14.

Summary of Fixed Customer Charges

Class	Current Customer Charge (OAG)	DEA Proposed Charge	Settlement Agreement
Residential & Farm	$8.00	$10.00	$9.00
Residential & Farm Demand Control	$11.00	$13.00	$12.00
Residential & Farm Time of Day	$11.00	$13.00	$12.00
Irrigation	$24.00	$30.00	$30.00
Small Gen. Service	$10.00	$14.00	$14.00
General Service	$28.00	$34.00	$34.00
General Service – TOD	$30.00	$36.00	$36.00
C&I Interruptible	$80.00	$110.00	$110.00

OAG

The OAG recommended that the customer charges remain unchanged for the residential and farm class as well as the small general service class. In addition, the OAG recommended that the Commission carefully consider DEA's proposed customer charges for the general service and C&I interruptible classes due to environmental harm they may incentivize.[252]

According to OAG, DEA proposed to increase the customer charges by 21-40%, while requesting an overall revenue increase of 2.1%. The OAG commented that the magnitude of the proposed increase in the customer charges is quite drastic when compared to the overall rate increase.[253]

The OAG stated it cannot support a proposed rate design with a structure that does not encourage conservation and therefore would create a societal cost. The OAG went further and stated that

[252] Ex. 200, Nelson Direct, p. 41.
[253] *Id.*, p. 33.

this rate design would actually encourage energy consumption within the general service and C&I interruptible classes.[254]

The OAG calculated that under DEA's original proposal it will increase its fixed revenue collection by 26% by increasing the customer charges. The OAG noted that DEA requested an increase in total revenues in this case of $4.1 million and $2.8 million of new revenues would come from the customer charge under DEA's proposal. The OAG found it concerning that over 90% of the new fixed revenues would be provided by the residential and farm and small general service classes when they currently provide only 60% of DEA's total revenues.[255]

The OAG stated that the costs of raising the customer charge are (1) the impact a decrease in the volumetric charge has on conservation and (2) the financial burden it places on low-use and potentially low-income customers. The OAG noted that these costs are incurred by ratepayers and society, not the Company.[256]

According to the OAG, DEA's rate design proposal encourages energy consumption, rather than conservation, by reducing or maintaining volumetric rates for the general service and interruptible classes, which would cause unnecessary societal costs in the form of pollution and CO2 emissions. By lowering the energy charges or keeping it constant (which equates to lowering rates when inflation is factored in) for these classes, the OAG stated that DEA is encouraging these classes to consume more.[257]

Using economic analysis (a simplified point-price elasticity calculation), the OAG compared consumption under DEA's proposed customer charge to the current customer charge. According to the OAG, under DEA's proposed customer charge, the residential and farm class would consume 5.6 million kWh more than under the current customer charge. The DEA stated that its analysis shows that increasing the customer charge as proposed by DEA would lead to an increase in consumption, rather than conservation and maintaining the customer charge at $8 would be equivalent to eliminating the electricity consumption of approximately 610 residential customers within DEA's territory.[258]

The OAG's Response to the Department

The OAG objected to the Department's assumption that $23.39 should be recovered through the customer charge. The OAG stated that this assumption is incorrect, because it includes a large cost driver that both DEA and the OAG agree should not be collected through the customer charge.[259]

According to the OAG, DEA did not recommend that $23.69 be recovered through the customer charge and instead suggested that $11.65 should eventually be recovered through the customer charge and the difference between these two numbers is the monthly cost of the primary lines,

[254] *Id*., p. 38.
[255] *Id*., p. 36.
[256] *Id*., p. 34.
[257] *Id*., p. 38.
[258] *Id*., p. 39.
[259] Ex. 201, Nelson Rebuttal, p. 7.

which DEA stated should not be used to calculate the customer costs for purposes of the customer charge.[260]

Because the costs associated with the distribution system do not vary by the number of customers, it is not appropriate to recover these costs through the customer charge.[261] The OAG noted that a foreseeable reason that may justify recovering distribution system costs through a customer charge could be a high rate of distributed generation participation within a utility's territory. However, the OAG noted also that DEA has not indicated that this is an issue currently, and, if it ever becomes an issue, it is unclear that an increase in the customer charge would be appropriate. [262]

In addition, the OAG stated its position is not that DEA should be able to collect $11.65. Instead the OAG objected to the Department's assumption to more clearly identify the customer costs. The OAG stated further that, once the correct customer costs have been calculated, it is a policy decision as to how those costs are recovered by DEA. The OAG asserted that if the incorrect customer costs are being analyzed, the Commission will not have accurate information within the record on which to base their decisions.[263]

The Department's Response to OAG

The Department stated that the results of DEA's CCOSS show residential customer costs of $23.39 per customer per month. The Department stated further that it included the cost of the primary line when determining whether an intra- class subsidy exists, because the cost of the primary line remains a customer cost, and is necessary for DEA to serve a customer.[264]

According to the Department, in order to serve a customer, electricity has to be delivered through the primary line to their home, and that cost remains whether a customer uses any electricity in a given month or not. Failing to recover primary line costs through a fixed charge means other customers are paying for primary line costs through their energy charges.[265]

In addition, the Department indicated that as distributed generation (DG) facilities such as rooftop solar systems expand, it will be increasingly important that the monthly fixed charges reflect more of the fixed costs of the distribution system, so as to minimize the rate impact on the customers without DG facilities.[266]

ALJ Report

The ALJ report recommended that the Commission approve all of the proposed fixed customer charges in accordance with the Settlement Agreement, with the exception of the proposed monthly fixed charge for the Small General Service class. The ALJ Report recommended the

[260] *Id*.
[261] *Id*., p. 12.
[262] *Id*., See fn 6, p. 8.
[263] *Id*., p. 9.
[264] Ex. 305, Peirce Surrebuttal, p. 8.
[265] *Id*., p. 5-6.
[266] *Id*., p. 8.

Commission approve a monthly fixed customer charge of $12.00 for the Small General Service Class. Specifically, in regard to monthly fixed charges, the Commission reached the following conclusions:[267]

> 165. The Administrative Law Judge finds that the level of fixed customer charge affects the extent to which volumetric charge subsidizes the actual fixed costs of providing service. The closer a fixed customer charge is to the actual cost of providing service, the less of the volumetric charge will be used to subsidize fixed costs. Therefore, artificially low fixed customer charges tend to result in higher-use customers subsidizing the fixed costs of lower-use customers. Conversely, higher fixed customer charges, if they are close to the fixed cost of providing service, provide a more accurate account to customers of the actual fixed cost of utility service and are more fair, financially, to higher-use customers.
>
> 166. In addition, the Administrative Law Judge finds that the record in this matter demonstrates that at the current $8.00 fixed customer charge, some low-income, higher-use customers subsidize low-use customers, on average, at a rate of $6.14 per month. These low-income, high-use customers are harmed even more than the low- income, low-use customers would be by a $1.00 per month increase in the customer charge, which would lower the intra-class subsidy. This concern about the intra-class subsidy, including its effect on low-income customers, drove the Department's proposal to increase the fixed customer charge to $9.00 per month.
>
> 167. The Administrative Law Judge finds that there is adequate support in the record to conclude that DEA's proposed Residential and Farm class fixed customer charge rate design includes sufficient conservation incentives, even with a $9.00 fixed customer charge. In the view of the Administrative Law Judge, the OAG's analysis of energy savings to be achieved by maintaining a lower fixed-customer charge fails to account for the common-sense argument that DEA's conservation incentives will continue to promote conservation. These incentives include the customer's incentive to lower monthly bills by lowering volumetric use and thus the volumetric portion of the bill, as well as the conservation improvement programs in which DEA and its energy partner, GRE, will continue to participate.
>
> 168. The OAG raises a noteworthy argument that the customer charge should be based solely on the secondary, fixed costs of the customer rather than the primary line. The OAG's concerns in this regard are especially salient in view of the concerns raised about the minimum-size method and the extent to which some distribution costs remain in the customer costs. However, the OAG did not provide precedent for approaching the fixed-customer charge calculation in this manner. In addition, the Department raised important questions that were not addressed by the OAG regarding how DG facilities should be factored into this calculation. Furthermore, regardless of which party's calculation of fixed

[267] OAH, *Findings of Fact, Conclusions of Law and Recommendations,* March 2, 2015, ¶¶ 165-171, p. 41-42.

customer costs is used, it is undisputed that a $1.00 increase in the fixed customer charge will still leave a portion of the Residential and Farm Service class costs unpaid.

169. Because a $1.00 increase in the fixed customer charge supports the principles of gradually bringing the fixed customer charge to the class's fixed cost of service in a manner that does not promote intra-class subsidies or discourage conservation, the Administrative Law Judge respectfully recommends that the Commission approve the proposed $1.00 increase in the Residential and Farm class service fixed customer charges.

170. With regard to DEA's proposal to increase the fixed customer charge for the Small General Service class by 40 percent (or $4.00), the Administrative Law Judge finds this proposal fails to adequately consider the principles favoring gradual increases in fixed customer charges, avoiding rate shock and encouraging reasonable efforts toward conservation. While the parties provided little testimony specific to this customer class, the Administrative Law Judge notes that a 40 percent increase in the fixed customer charge is not gradual and could constitute rate shock. The increase is especially troubling given that the proposed increase in this class's volumetric charge is only 2 percent, an amount that, if increased, could support conservation goals more strongly. While the Administrative Law Judge recognizes the importance of bringing fixed customer charges closer to each class's fixed cost of service, this proposal increases the Small General Service class too abruptly. The Administrative Law Judge respectfully recommends that the Commission approve a fixed customer charge of $12.00, which would be a 20 percent increase for the Small General Service class, and adjust the volumetric charge accordingly.

171. The Administrative Law Judge respectfully recommends that the Commission approve all of the remaining proposed fixed customer charges in accordance with the Settlement Agreement.

Exceptions to the ALJ Report

The Department did not file Exceptions to the Administrative Law Judge's Findings of Fact, Conclusions and Recommendations.

DEA

DEA took exception to Paragraph 170 of the ALJ report, which recommended a smaller monthly fixed charge for Small General Service members. Paragraph 170 of the ALJ Report recommended the Commission approve a fixed customer charge of $12.00. DEA contended that the monthly fixed charge for Small General Service should be increased from the present $10.00 to $14.00 as contained in its initial filing and agreed to with the Department in the Settlement Agreement. DEA stated it requested increases in the monthly fixed charge based on the costs it incurs to stand ready to provide electric service, excluding costs for primary line.

DEA stated further that the proposed $4.00 monthly increase in the Small General Service fixed charge makes a meaningful move toward cost recovery, while recognizing political, policy and rate design considerations.

DEA claimed that an artificially low fixed charge tends to result in higher-use consumers subsidizing the fixed costs of lower-use consumers and that the fixed charges close to the cost of service provide a more accurate price signal to consumers of the actual fixed cost of utility service and are financially more fair to higher-use consumers.

OAG

In its Exceptions to the Administrative Law Judge's Findings of Fact, Conclusions and Recommendations, the OAG recommended the Commission make significant modifications to paragraphs 166 to 170 of the ALJ Report, because The ALJ Report's recommendation is based on an exaggerated estimate of the costs that should be recovered in the customer charge.

The OAG stated that the ALJ Report appears not to have appropriately considered the impact that raising the customer charge would have on low-income customer's bills and the ALJ's Findings appear to minimize the meaningful conservation benefits that would result from maintaining the existing customer charge. For these reasons, the OAG took exception to the ALJ Report's recommendation to increase the customer charges for residential and small business customers, and to the Findings that support this recommendation.

Specifically, the OAG claimed that the ALJ inappropriately relied on the Department's claim that the customer charge should recover all of the costs classified as "customer costs" in the CCOSS—which the Department claimed were $23.39. The OAG explained why some of these costs, such as the costs of primary lines, are not appropriate to consider in setting the customer charge. The OAG noted that while the ALJ Reports stated that the OAG "raise[d] a noteworthy argument that the customer charge should be based solely on the secondary, fixed costs of the customer rather than the primary line," the ALJ Report did not support the removal of the primary line from customer costs because "the OAG did not provide precedent for approaching the fixed customer charge calculation in this manner."

The OAG stated it is not aware of a Commission decision in which this issue has been disputed, and the validity of the OAG's analysis should not be rejected because the Commission has not previously ruled affirmatively on this issue. Moreover, the OAG stated it had raised a similar issue in Xcel's existing rate case, ibn which the ALJ Report recommended maintaining the current customer charge. The OAG noted that the ALJ Report in the Xcel rate case stated the following:

> While reference to the CCOSS analysis is appropriate for revenue apportionment purposes, CEI and the OAG have raised valid questions about whether the average customer costs calculated by the Company's CCOSS should be used in determining the fixed monthly customer charge. Consequently, the Administrative Law Judge finds it is appropriate to give less weight in this proceeding to the goal of moving the customer charges closer to cost as measured by the CCOSS in results than in prior proceedings.

For the same reasons, the OAG stated the customer costs identified in the CCOSS should not be used to inform the customer charge decision for DEA.

In addition, the OAG claimed the ALJ's recommendation to increase the customer charge does not consider the OAG's analysis of the effect that raising the customer charge will have on low-income customers. According to the OAG, the ALJ Report does not reflect that the analysis demonstrated that maintaining a low customer charge would benefit the majority of low-income customers.

Instead, the OAG noted that the ALJ focused on the Department's argument that Dakota's current customer charge results in low-income, high-use customers paying a $6.14 monthly intra-class subsidy. The OAG reiterated that this claimed subsidy is based on a flawed CCOSS that overestimated the customer cost portion of the distribution system, and more importantly, by focusing on claimed intra-class subsidies paid by a few low-income customers, the Department's argument failed to consider the detrimental effect that raising the customer charge will have on the bills of low-income customers as a whole.

Finally, the OAG claimed that the ALJ inappropriately ignored the effect that maintaining the existing customer charge will have on energy conservation. The OAG again noted that maintaining a lower customer charge promotes conservation by increasing the volumetric charge, providing a greater reward to customers who reduce their energy consumption.

While the ALJ Report claimed, that even with an increased customer charge (and lower volumetric charge), DEA's ratepayers will have an incentive to conserve energy, and that Dakota will continue to participate in conservation improvement programs, the OAG asserted that this analysis, ignores the *degree* to which Dakota's customers are incented to conserve.

The OAG noted it had provided quantitative analysis demonstrating how maintaining the customer charge at its current level would considerably reduce energy consumption by increasing the incentive to conserve. The OAG's recommendation promotes the statutory mandate that "[t]o the maximum reasonable extent, the Commission shall set rates to encourage energy conservation…"

The OAG recommended removing Findings 166 through 171 from ALJ's Report and replacing them with the following:

> 166. <u>The record in this matter demonstrates that the customer charge of $8.00 pays for a substantial portion of the customer costs generated by the CCOSS, when primary lines are excluded. The record further demonstrates that it is not appropriate to include the costs of primary lines in the costs used to inform the customer charge.</u>
>
> 167. <u>The OAG has provided extensive and persuasive, quantitative evidence demonstrating that increasing the customer charge will have detrimental effects on the majority of low-income customers. In addition, the OAG has demonstrated that the effect of maintaining the current customer charge will have minimal effects on a small number of high-use, low income customers.</u>

168. The record in this matter also demonstrates that increasing the customer charge will have a negative effect on customers incentive to conserve. This conflicts with the statutory directive to "set rates to encourage energy conservation." Minn. Stat. § 216B.03 (2014).

169. For these reasons, it is appropriate and reasonable to maintain the existing $8 customer charge for the Residential class and the $10 customer charge for the Small General Service class.

Staff Analysis

The Settlement Agreement between DEA and the Department, if adopted, would increase DEA's monthly fixed customer charge for Residential and Farm Service by $1.00, Small General Service by $4.00, Irrigation and General Service by $6.00, and C&I Interruptible by $30.00 per month. The ALJ recommended that the Small General Service monthly fixed charge by increased by $2.00 instead of $4.00 as proposed in the Settlement Agreement. The total dollar and the percentage increase for each customer class, according to the ALJ recommendation, is given in the Table below:

				Proposed Increase	
Schedule	Rate Class	Current	Proposed	($)	(%)
31	Residential & Farm Service	$8.00	$9.00	$1.00	12.50%
32	Residential & Farm Demand Control	$11.00	$12.00	$1.00	9.09%
53	Residential and Farm Service (Time-of-Day Rate)	$11.00	$12.00	$1.00	9.09%
45	Low Wattage Unmetered Service	$8.00	$10.00	$2.00	25.00%
41	Small General Service	$10.00	$12.00	$2.00	20.00%
36	Irrigation Services	$24.00	$30.00	$6.00	25.00%
46	General Service	$28.00	$34.00	$6.00	21.43%
54	General Service Optional Time-of-Day Rate	$30.00	$36.00	$6.00	20.00%
70	C&I Interruptible Services	$80.00	$110.00	$30.00	37.50%

Staff again has concerns that the proposed increase in the fixed monthly charges relies to a significant extent upon a deficient DEA CCOSS that used the minimum-sized study to classify distribution accounts between customer and demand costs. Staff is in agreement with the OAG that the use of CCOSS to determine customer costs, and basing policy arguments for increasing the fixed monthly charges to more accurately reflect customer costs, presents serious concerns. Staff believes the OAG has raised valid questions in regard to DEA's CCOSS; therefore the Commission may want to give non-cost factors greater weight than cost factors when considering whether to increase the fixed monthly charges.

Among the non-cost factors the Commission may wish to give consideration, is the impact of the increase in the fixed monthly charges upon low-income individuals. Both the Department and the OAG make arguments that their position will benefit to a greater extent low-income households. The Department implied that a low fixed monthly charge has a negative impact on low income, high-use customers.

The Department offered significant analysis on the impacts on intra-class subsidies on DEA's members. Specifically, the Department made the following comments on the impacts of intra-class subsidies on low-income, high usage customers:[268]

> [C]ustomers who use more energy would pay for costs that they do not impose on the system. Overpayments by such customers subsidize other customers within the same class who pay less than the cost to serve them. Such outcomes, called intra-class subsidies, should be minimized. …[L]ow-income customers who use larger amounts of energy would pay lower bills if customer charges were set closer to costs because these customers would not have to pay the subsidy in their energy charge to offset the customer costs that low-use (but not necessarily low-income) customers impose on the system for which they do not pay. …While the Commission certainly has latitude to design rates as it sees appropriate, the policies chosen should be based on a well-informed record. …The DOC strongly recommends that the Commission promote goals of fairness and provide appropriate price information by adopting rates that are based on cost, to the extent possible. Requiring some customers to pay for customer-related costs that they do not impose on the system while allowing other customers to avoid paying for the costs they impose on the system not only moves away from those goals, it also could lead to unintended consequences, such as either under-recovery or over-recovery of customer-related costs.

Staff makes a couple observations on the Department's statements in regard to intra-class subsidies and the impacts on low-income, high-usage customers. First, the Department does not mention the impact of an increased customer charge on DEA's low-income, low-usage customers. The OAG provided an analysis that attempted to measure the impact of increasing the fixed monthly charge on all low-income customers, both low- and high-usage. The OAG compared the consumption of assisted customers (defined as receiving financial assistance) to non-assisted customers within DEA's territory and found that assisted customers consumed far less electricity than non-assisted customers.[269] This would appear to indicate that low income customers are more likely to be negatively impacted by a high customer charge than a high income customer.

In addition, Staff notes that in the most recent Xcel rate case, several parties objected to an increase in the fixed monthly customer charge due to the negative impact such an increase would have on low-income customers. The Energy Cents Coalition (ECC) opposed increasing the customer charge due to its concern for energy affordability for low-income households and low-income renters, in particular.[270] According to ECC, increasing the residential customer charge would result in low-income, low-use customers subsidizing high-use customers who are

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[268] Ex. 304, Peirce Direct, p. 10-13.
[269] Ex. 201, Nelson Rebuttal, p. 18-21.
[270] Docket No. 13-868, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Ex. 235, Marshall Direct, p. 1 & 4.

predominately of higher income.[271] The American Association of Retired Persons (AARP) also opposed any increase to the fixed monthly customer charges in the Xcel rate case, in order to avoid placing an undue burden on low-use, residential customers.[272] AARP asserted that raising the customer charge translates into a higher percentage increase for low-use customers than it does for high-use customers based on the total bill, and that Xcel's proposed increase is significant for low-income households.[273] AARP also argued that maintaining the current fixed monthly customer charges would benefit greater numbers of households than increasing the customer charges because there are many more customers with below-average usage than there are customers with above-average usage.[274]

Second, Staff wishes to point out that the issue of fairness and intra-class subsidies are subjective issues that require the policy judgement of the Commission when making a decision. While Staff agrees with the Department that high-usage customers may subsidize low-usage customers if the monthly fixed customer charge does not cover the cost for customers to connect to the system, determining how much cost low-use and high-use customers impose on the system is not a simple calculation. For example, the Department's breakeven analysis attempts to calculate the breakeven point for the amount of usage customer need to recover customer costs through energy rates. As the OAG described above, an important consideration in this analysis is what makes up the customer costs. While the OAG and DEA do not consider Primary lines to be part of customer costs, the Department argues that these costs should be included. The Department stated the following in regard to primary lines and customer costs:[275]

> The cost of the primary line remains a customer cost, and is necessary for DEA to serve a customer. In order to serve a customer, electricity has to be delivered through the primary line to their home, and that cost remains whether a customer uses any electricity in a given month or not. Failing to recover primary line costs through a fixed charge means other customers are paying part of those primary line costs through their energy charges.

Staff agrees with the Department that if the primary line costs are not recovered through a fixed charge than customers are paying for the primary line through their demand charges or variable energy rates. However, determining whether or not such a rate design is fair requires the policy judgement of the Commission.

As the NARUC Electricity manual states, "[d]istribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads," and "[l]ocal area loads are the major factors in sizing distribution equipment." This implies that a distribution system designed to serve low-usage customers would be smaller and less costly than a distribution system designed to meet high-usage customers. Under this assumption, it would be reasonable to conclude that actual costs of the distribution system should be paid through the use of that system, or through variable rates that are based on the amount of energy each customer consumes. Removing the primary line from the customer costs is reasonable in this case and is

[271] Docket No. 13-868, Ex. 242, Colton Opening Statement, p. 2.
[272] *Id.*, AARP Initial Brief, p. 20.
[273] *Id.*, Ex. 310, Brockway Direct, pp. 32-33.
[274] *Id.*, p. 28 and Ex. 312, Brockway Rebuttal, p. 10.
[275] Docket No. 14-482, Ex. 305, Peirce Surrebuttal, pp. 5-6.

likely the reason DEA chose not to include the costs for primary lines within customer costs in the first place.

DEA stated that the monthly fixed charge should be set to recover the costs it incurs to stand ready to provide electric service, excluding costs for primary line. While staff agrees with removing the costs of the primary line from customer charges, Staff also wishes to point out that standing ready to provide electric service is a different standard than the cost for a customer to connect to the system. Standing ready to serve may be interpreted to include potential future costs. While using the standing ready to provide electric service standard may be a reasonable policy decision, using this standard instead of a standard for the cost for a customer to connect to the system requires the judgment of the Commission.

Staff uses the following statement by the Department, as an example: [276]

> The price signals sent to customers ought to reflect the costs of serving them, including the fixed cost of providing them service whether or not they use any electricity. In addition, as distributed generation (DG) facilities such as rooftop solar systems expand, it will be increasingly important that the fixed charges associated serving a customer reflect their cost so as to minimize the rate impact on the customers without DG facilities.

While the potential for DG facilities to impact the recovery of the fixed costs of distribution system through variable energy rates is an emerging topic of conversation, the Department assumes, without record support, that customers with DG facilities, such as rooftop solar systems, automatically impose costs on the system that are paid for by customers without DG facilities. Such an argument is more accurately described with an assumption that customers with DG facilities should pay the utility for standing ready to provide electric service to these customers should the sun not shine or the solar panels fail. In other words, customers with DG facilities should be required to pay more than their usage fees and should also pay for the potential future use of the system through increased fixed monthly rates.

If customers with DG facilities paid higher fixed monthly customer charges than those without DG facilities, the intra-class subsidies could be interpreted to move in the opposite direction as presented by the Department. While this policy issue may be heard in the future when the issue is more appropriately before the Commission, Staff notes that it could be reasonably concluded that low-use DG customers would be subsidizing high-use non-DG customers, through the increased monthly fixed charge, because they impose less costs on the system than the high-use customer without DG.

Again, while the issue of DG facilities is not directly before the Commission, this example demonstrates how much intra-class subsidies depend on what is included in the customer costs and on the policy judgement of the Commission.

[276] *Id*., p. 8. Staff notes that this statement of the Department was not an issue in this case and that the DEA did not indicate that installed DG on its system was having an impact on its ability to recover costs. However, the ALJ report did base its recommendation to increase customer charges, at least partly, on the impact of DG in the future. See ¶168 of the ALJ Report.

Staff notes that in determining the level to set the fixed monthly basic customer charges, the policy judgments of the Commission rest largely upon a balancing of cost and non-cost factors. Factors the Commission may consider and balance in setting rates and allocating the resulting revenue collection among customer classes include:

- Rates are sufficient to allow the utility to collect its legitimate costs;
- Promotion of revenue stability for the utility;
- Customer's ability to pay (Minn. Stat. § 216B.16, subd. 15);
- Cost of service to the various customer classes;
- Encouraging renewable energy;
- Sufficiently gradual changes so as not to destabilize rates or cause rate shock;
- Historical continuity;
- Customer's ability to pass along increases;
- Customer's ability to deduct utility expenses on taxes;
- Customer's ability to bypass the utility;
- Understandable to customers;
- Acceptable to customers;
- Energy conservation (Minn. Stat. §§ 216B.03, 216B.2401);
- Recovery of reasonable amounts of economic development expenses (Minn. Stat. § 216B.16, subd. 13);
- Administratively feasible;

Staff notes further that the OAG provided extensive analysis in the record on the impacts that DEA's proposed increase in the fixed monthly charges would have on energy conservation. This analysis was not refuted by either DEA or the Department. In addition, the OAG concluded that the increases in the Monthly Fixed customer charges did not meet the statutory mandate in Minn. Stat. § 216B.03 that "[t]o the maximum reasonable extent, the Commission shall set rates to encourage energy conservation ."

In addition, Staff notes that the correct "price signals" that the Department refers to as justification for increasing the fixed monthly customer charge are direct signals to customers, through decreased variable energy rates, to consume more electricity. In this case, the correct price signal the Department justifies for the recovery of DEA's costs may also be interpreted as the incorrect price signal when considering conservation policy goals and statutory mandates. This is another policy decision that requires the judgement of the Commission.

Finally, Staff notes that, if the Commission has reservations in regard to the acceptance of the results of DEA's CCOSS, the Commission may wish to rely more upon non-cost factors when choosing between rate design alternatives for fixed monthly customer charges.

Decision Alternatives – Monthly Fixed Customer Charges

(Note: The following decision alternatives correspond to 11:A-D in the Deliberation Outline, pp. 9-10.)

A. Approve the increases in the fixed monthly customer charges as set forth in the Settlement Agreement between DEA and the Department; **and**

Amend the ALJ Report (Finding 170) to authorize a $14.00 per month customer charge for the Small General Service customer class as recommended by DEA. (DEA)

B. Approve the increases in the fixed monthly customer charges as set forth in the Settlement between the DEA and the Department, with the exception of the Small General Service class. Increase the fixed monthly customer charges for the Small General Service class from $10.00 to $12.00. (Department, ALJ)

C. Do not approve an increase in the fixed monthly customer charges for either the Residential & Farm or the Small General Service Classes. (OAG); **and**

Amend the ALJ Report by not adopting Findings 166 through 170 and replacing them with the following:

> 166. The record in this matter demonstrates that the customer charge of $8.00 pays for a substantial portion of the customer costs generated by the CCOSS, when primary lines are excluded. The record further demonstrates that it is not appropriate to include the costs of primary lines in the costs used to inform the customer charge.
>
> 167. The OAG has provided extensive and persuasive, quantitative evidence demonstrating that increasing the customer charge will have detrimental effects on the majority of low-income customers. In addition, the OAG has demonstrated that the effect of maintaining the current customer charge will have minimal effects on a small number of high-use, low income customers.
>
> 168. The record in this matter also demonstrates that increasing the customer charge will have a negative effect on customers incentive to conserve. This conflicts with the statutory directive to "set rates to encourage energy conservation." Minn. Stat. § 216B.03 (2014).
>
> 169. For these reasons, it is appropriate and reasonable to maintain the existing $8 customer charge for the Residential class and the $10 customer charge for the Small General Service class. (OAG) **or**

D. Do not approve any increase in the fixed monthly customer charges for any customer class and amend the ALJ Report accordingly. (OAG)

General Housekeeping and Compliance Issues

All of the compliance filing requirements in the decision alternatives are standard rate case compliance items. These requirements ensure that Dakota 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 also recommends the Commission include a set of financial summaries for Dakota in its order in this docket that includes: a schedule showing the calculation of Dakota'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 Alternatives – General Housekeeping and Compliance Issues

(Note: The following decision alternatives correspond to 12:A-C in the Deliberation Outline, pp. 10-11.)

A. State that the final order in this docket shall contain summary financial schedules including: a calculation of DEA'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.

B. Require DEA to make the following compliance filings within 30 days of the date of the final order in this docket:

   1. 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:

      a. Breakdown of Total Operating Revenues by type;
      b. 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.
      c. Revised tariff sheets incorporating authorized rate design decisions;
      d. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.

2. 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.

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

4. Direct DEA to file a computation of the base DSM & Conservation Recovery rate, based upon the decisions made herein for inclusion in the final Order. Direct DEA to file a schedule detailing the DSM & Conservation Recovery tracker balance at the beginning of interim rates, the revenues (both base and the Resource and Tax Adjustment rate recovery) and costs recorded during the period of interim rates, and the DSM & Conservation Recovery tracker balance at the time final rates become effective.

5. 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.

C. Authorize comments on all compliance filings within 20 days of the date they are filed. However, comments are not necessary on DEA's proposed customer notice.