Minnesota Public Utilities Commission

Staff Briefing Papers

Meeting Date: September 18 & 24, 2014 .... Agenda Item # __

Company: Minnesota Energy Resources Corporation (MERC or the Company)

Docket No. G-011/GR-13-617
In the Matter of a Petition by Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota

Issues: Should the Commission adopt the recommendations in the ALJ's Report? If not, what level of revenue is appropriate for the Company during the test year? How should that revenue be collected from its customers?

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Relevant Documents

Post-Hearing Summary of Disputed and Resolved Issues
Minnesota Energy Resources Corp. (MERC) - Summary of Issues............................ Jun. 6, 2014
Minnesota Department of Commerce (Department)
Revisions to MERC's issue summary - legislative format .... Jun. 24, 2014
Revisions to MERC's issue summary - clean copy .... Jun. 24, 2014
Super Large Gas Intervenors (SLGI) - Comments .... Jun. 24, 2014

Initial Briefs
MERC .... Jun. 24, 2014
MERC - Errata to initial brief .... Jul. 30, 2014
Department.. Jun. 24, 2014
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Reply Briefs
MERC .... Jul. 11, 2014
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Department – Attachment 1 to Reply Brief .... Jul. 11, 2014
OAG-AUD .... Jul. 11, 2014

<u>Proposed Findings of Fact</u>

<u>ALJ Report</u>

<u>Exceptions to the ALJ Report</u>

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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September 11, 2014

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Statement of the Issue

Should the Commission adopt the recommendations in the ALJ's Report? If not, what level of revenue is appropriate for the Company during the test year? How should that revenue be collected from its customers?

Introduction

On August 12, 2014, Administrative Law Judge Eric L. Lipman (ALJ) issued his Findings of Fact, Summary of Public Testimony, Conclusions of Law and Recommendation (ALJ Report).

On August 25 and 26, 2014, MERC filed schedules that reflect MERC's interpretation of the adjustments to the test year revenue requirement and rate design recommended by the ALJ. According to MERC's interpretation, if the Commission adopts the recommendations in the ALJ's Report in its entirety, MERC's request for a $14,187,597 (or approximately 5.52 percent) rate increase would be reduced to a ($231,264) (or approximately (0.1) percent) rate decrease, based on a rate of return on common equity of 9.79 percent. However, it should be noted that the rate decrease is not a real rate decrease because it appears to reflect MERC's interpretation of the ALJ recommendation to remove CIP cost recovery entirely from "base" rates and to completely shift cost recovery for CIP into a separate rate mechanism.

On August 28, 2014, the Department filed a letter commenting on MERC's compliance filing. The Department agreed with MERC's revised financial schedules except for MERC's cost of gas adjustment. On September 8, 2014 the Department filed a supplemental letter in which it concluded, upon further review, that MERC's income statement adjustments also include an incorrect Conservation Improvement Program (CIP) revenue adjustment. The Department included financial schedules which reflect its interpretation of the ALJ's recommendations. According to the Department's interpretation, if the Commission adopts the recommendation in the ALJ's Report in its entirety, MERC's request for a $14,187,597 rate increase would be reduced to a $5,426,948 (or approximately 1.8 percent) rate increase.

MERC	As filed	ALJ Recommendation as interpreted by MERC	ALJ Recommendation as interpreted by the Department
Revenue Deficiency	$14,187,597	($231,264)	$5,426,948
Percentage Change[1]	5.52%	(0.1%)	1.8%

On September 10, 2014, MERC submitted a reply to the Department's September 8 supplemental comments. MERC outlined its view of the three possible alternatives for handling CIP cost recovery going forward.

The main issue before the Commission at this meeting is whether to adopt the ALJ's Report. If the Commission does not accept the ALJ's Report (and recommendations) in its entirety, then, depending on the modifications the Commission makes to the ALJ's recommendations, the

[1] These percentage amounts are approximations and were not necessarily calculated using identical numbers in the denominator for MERC's current revenue under currently authorized rates and test-year sales volumes.

Commission will need to decide what level of revenue is appropriate for the Company for the test year, and how that revenue should be collected from its customers.

Background

On September 30, 2013, Minnesota Energy Resources Corporation (MERC) filed a general rate case with the Minnesota Public Utilities Commission (Commission) under Docket No. G-011/GR-13-617. The Company asked for an increase in its Minnesota retail natural gas rates of approximately $14.188 million, or 5.52%, based on a proposed return on equity of 10.75%.[2, 3] MERC proposed a forecasted test year ending on December 31, 2014. In its proposed test year, MERC proposed that it would have approximately 214,691 customers and sales (i.e. throughput including transportation) of approximately 66.3 Bcf of gas.

On November 27, 2013, the Commission issued three Orders.[4] In those Orders, the Commission accepted MERC's filing, suspended the proposed final rates until the end of this case,[5] and set this matter for contested case hearing. Administrative Law Judge (ALJ) Eric L. Lipman of the Minnesota Office of Administrative Hearings (OAH) was assigned to conduct the case. The Commission also authorized an interim rate increase of $10,755,973 per year, or approximately 4.2 percent,[6] effective November 29, 2013[7] and subject to refund.

The intervenors[8] in this case are

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[2] MERC is wholly owned by Integrys. The Integrys Energy Group, Inc. (Integrys) is a diversified energy holding company with regulated natural gas and electric utility operations, nonregulated energy operations, and an approximate 34% equity ownership interest in ATC, a regulated electric transmission company. Integrys was incorporated in Wisconsin in 1993. MERC is a part of Integrys' natural gas utility segment. The Integrys natural gas utility segment includes the regulated natural gas utility operations of WPS, MGU, MERC, PGL, and NSG. WPS, a Wisconsin corporation, began operations in 1883. MGU and MERC, both Delaware corporations, began operations upon the acquisition of existing natural gas distribution operations in Michigan and Minnesota, respectively, in April 2006 and July 2006, respectively. [Integrys, 2011 10-K Report, p. 2]

[3] MERC and its predecessors have filed three rate cases since 2000.

File Year	Utility Name	$ Increase Requested	% Increase	$ Final Increase Granted	Final %	ROE Allowed
2000	UtiliCorp	$ 9,846,647	6.24%	$6,220,310	4.00%	9.93%
2008	MERC	$ 22,041,889	6.38%	$15,418,492	5.49%	10.21%
2010	MERC	$ 15,165,309	5.18%	$11,047,296	4.19%	9.70%

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

[5] Because there were other rate cases pending when MERC submitted its application, the Commission extended the ten-month statutory deadline for issuing its final decision in this matter for ninety days, until October 28, 2014.

[6] The Commission granted MERC's request to collect less than the full amount of the interim rate increase from its SLV and FLEX rate customers. The Company shall not seek recovery of forgone interim rates from any customers.

[7] The Commission authorized MERC to put the interim rates into effect on November 29, 2013, thereby complying with the letter of the statute. The Commission also acknowledges MERC's waiver of its right to charge the interim rates as of November 29, 2013, and approves MERC's request to not begin charging the authorized interim rates until January 1, 2014.

[8] On March 24, 2013, the ALJ denied the ICI Group's request to intervene in this matter. In this case, the ICI Group members were U.S. Energy Services, Inc., and two of its interruptible transport service customers.

- Minnesota Energy Resources Corporation (MERC or the Company)
- Minnesota Department of Commerce-Division of Energy Resources (the Department or DOC)
- Minnesota Office of the Attorney General-Antitrust and Utilities Division (OAG-AUD)
- Super Large Gas Intervenors (SLGI)[9]
- Constellation New Energy – Gas Division, LLC (Constellation)

MERC, the Department, OAG-AUD, and Constellation submitted prefiled testimony in advance of the evidentiary hearings. SLGI did not. (Copies of the prefiled testimony is available electronically through the eDockets system.)

Judge Lipman held public hearings as follows:

Location, date, and time	Members of the public in attendance	Members of the public who spoke
Rochester - March 12, 2014 (12:30 p.m.) Olmstead County Government Center	8	6
Rosemount - March 12, 2014 (7:00 p.m.) Dakota County Vo-Tech College	1	1
Cloquet - March 13, 2014 (7:00 p.m.) Cloquet City Hall	3	3
Totals	12	10

In addition, approximately seventeen members of the public submitted written comments to the ALJ. Judge Lipman summarized the public comment and public testimony on p. 9 (paragraphs 36 – 40) and pp. 104-107 (sections X and XI) in his Report. According to Judge Lipman

> In general, these commentators expressed concerns as to the need, amount and frequency of rate increases. Likewise, several commentators expressed concern as to the impact that higher natural gas rates will have upon those with fixed incomes. (ALJ Report, p. 9, paragraph 40)

(Copies of the public hearing transcripts and the written public comments are available electronically.)

On May 13, 2014, the evidentiary (technical) hearing was held in St. Paul. (A copy of the evidentiary hearing transcript is available electronically.)

On June 6, 2014, MERC submitted its summary of disputed and resolved issues as requested by the ALJ. On June 24, 2014, the Department, and SLGI submitted comments on MERC's summary. Also on June 24, 2014, MERC, the Department, OAG-AUD filed initial briefs, and

[9] The Super Large Gas Intervenors (or SLGI) consist of the following members: (1) Hibbing Taconite Company located in Hibbing, Minnesota, (2) ArcelorMittal USA's Minorca Mine located near Virginia, Minnesota, (3) Northshore Mining Company located in Silver Bay, Minnesota (4) United Taconite, LLC located in Eveleth and Forbes, Minnesota, (5) the Minntac and Keewatin Mines of United States Steel Corporation located in Mountain Iron and Keewatin, Minnesota respectively, and (6) USG Interiors, Inc.

MERC filed its proposed findings of fact.[10] On July 11, 2014, MERC, the Department, OAG-AUD filed reply briefs and the Department and OAG-AUD filed their proposed findings of fact.

On August 12, 2014, Judge Lipman issued his 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 his Report.

Also, on August 25, 2014, MERC, the Department, OAG-AUD, filed comments taking exception or requesting clarification to various aspects of the ALJ's Report. The Super Large Gas Intervenors (SLGI) and Constellation New Energy- Gas Division (Constellation) did not file exceptions to the ALJ's report.

(Copies of these items are available electronically.)

Related Dockets

On February 4, 2014, Interstate Power and Light Company (IPL) and Minnesota Energy Resources Corporation (MERC) filed a joint petition for approval of the sale of IPL's Minnesota natural gas distribution system and assets, and the transfer of its Minnesota service rights and obligations, to MERC.[11] On June 30, 2014, the Commission issued its order requiring further development of the record in this matter. Staff expects this matter to be heard later this year.

On August 6, 2014, MERC submitted its requests that the Commission determine no action is required with respect to the proposed merger and combination of Integrys Energy Group, Inc. (MERC's parent company) and Wisconsin Energy Corporation (WEC) or, if the Commission finds that action on its part is required, approve, the proposed transaction as consistent with the public interest.[12] MERC's request is pending.

Financial Issues - Introduction

MERC was requested to provide financial schedules showing its interpretation of the ALJ's conclusions. The schedules were filed on August 25, 2014. On August 26, 2014, MERC refiled a more readable version of the financial schedules and included an additional schedule showing its updated uncollectable expense calculations. (MERC's August 25, 2014 schedules are included in eDockets as docket ID 20148-102517-01.)

On August 28, 2014, the Department submitted comments on MERC's interpretation of the ALJ's Report and recommendation. On September 8, 2014, the Department supplemented its August 28 comments and provided revised schedules that reflect the Department's interpretation of the ALJ recommendations. (These schedules are included in eDockets as docket ID 20149-102914-01.)

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[10] On July 30, 2014 MERC submitted errata to its initial brief.

[11] In the Matter of a Request for the Approval of the Asset Purchase and Sale Agreement Between Interstate Power and Light Company and Minnesota Energy Resources Corporation, Docket No. G-001, G-011/PA-14-107

[12] In the Matter of the Report of Minnesota Energy Resources Corporation on the Merger of Wisconsin Energy Corporation and Integrys Energy Group, Inc., Docket No. G-011/PA-14-664

The revenue deficiency calculation from MERC's and the Department's schedules are shown below. Most of the difference between MERC's and the Department's interpretation of the ALJ recommendation can be attributed to differences in how CIP revenues should be reflected in these schedules. This is discussed further in the briefing papers in the section on CIP. (MERC's September 10 reply to the Department's supplemental comments did not specifically address these schedules.)

MERC	As filed	ALJ Recommendation as interpreted by MERC	ALJ Recommendation as interpreted by the Department
Rate Base	$198,314,568	$191,993,874	$192,019,447
Rate of Return	8.0092%	7.5262%	7.5262%
Required Operating Income	$15,883,387	$14,449,843	$14,451,768
Operating Income	$7,557,332	$14,585,561	$11,266,939
Income Deficiency	$8,326,055	($135,718)	$3,184,829
Conversion Factor	1.7040	1.7040	1.7040
Revenue Deficiency	$14,187,597	($231,264)	$5,426,948

Many of the financial issues are resolved between MERC and the Department or the OAG. Many are not. The briefing papers are generally organized with the contested financial issues first, then a summary of uncontested financial issues that may be of interest. These sections are followed by CIP, Cost of Gas, Cost of Capital, Forecasting, Class Cost of Service and Rate Design.

Financial Issues - Contested and Other

The following issues are contested by one or more of the parties or may still be contested by the parties. Certain other issues are discussed because Commission precedent may suggest the issue be resolved in a way that is different from the approach advocated by the parties. Other issues are discussed because the Commission indicated an interest in the issue in an Order or in some other way.

Property Tax Expense

PUC Staff: Ann Schwieger

The amount to include in the test year Taxes Other than Income is disputed by the OAG which recommended $6,624,033 of expense in the test year. MERC, the Department and the ALJ agree that the appropriate level of test year expense for Taxes Other than Income should be $7,195,896.

The Company initially forecasted a 2014 test year expense of $7,314,733. The forecasted amount included $375,000 of Kansas Ad Valorem Tax associated with stored gas passing through the state. The Minnesota property tax expense forecast had been inflated to represent the increase in Minnesota property tax expense that the Company has been experiencing over the past several years. MERC has filed appeals in tax court for both their Minnesota (2008-2013) and Kansas ad valorem taxes (2009-2013).

MERC proposed a decrease of $118,864 in the 2014 test year in the accrual for Taxes Other than Income. The Company lowered its estimate by $70,000 for the Kansas gas storage tax based on information received from the Kansas Attorney General. MERC reduced its test year estimate for Minnesota property taxes by $48,864. MERC's revision was the result of reducing the inflation rate it used to estimate Minnesota property taxes from 5.09% to 4.35%, or a .74% inflation rate reduction. As a result of the proposed decrease MERC requested a 2014 test year Taxes Other than Income expense of $7,195,869.

Based upon its review of a limited sample of property tax statements for MERC property in Minnesota, the OAG argued that the property tax test year expense is overstated. The OAG also stated the MERC's estimate was inflated twice for inflation. The OAG objected to MERC's projection of 2014 test year costs by using 2012 as a base year. The OAG argued that using the actual 2013 property tax expense as the test year property tax expense would be a better representation of the liability. The ALJ disagreed with the OAG's position because MERC's actual property tax liability for 2012, which was paid in 2013, was greater than the OAG's estimate for MERC's 2014 property tax expense. The ALJ stated that the Company's expectation of still higher property tax was well grounded in the hearing record and found that MERC's 2014 test year Taxes Other than Income expense of $7,195,869 is appropriate.

The Company, Department and the ALJ agreed to the following when pending appeals are resolved:

- Ratepayers should be made whole for all Kansas ad valorem taxes which have been remitted to MERC, but for which it is later determined that MERC was not liable;

- Refund the amount of Kansas property taxes collected from customers for the years under appeal, less the amount ultimately paid to Kansas for all years under appeal;

- Remit any refunds due to ratepayers with interest;

- Notify the Commission of any court rulings issued prior to the Commission's final order in this proceeding; and

- Make a compliance filing upon resolution of either the Minnesota property tax appeal or the Kansas ad valorem tax litigation.

Staff Analysis

Because of the limited sample size the OAG used to support its argument plus the overall trend of upward pressure on property taxes, Staff agrees with the Company, the Department and the ALJ and recommends the Commission approve a 2014 test year Taxes Other than Income expense of $7,195,869 along with the agreed stipulations above.

Decision Alternatives for Property Tax Expense

1. Approve a 2014 test year Taxes Other than Income Expense of $7,195,869. (Company, Department, ALJ)

2. Approve a 2014 test year Taxes Other than Income Expense of $6,624,033. (OAG)

3. Require the Company to:

    - Refund the amount of Kansas property taxes collected from customers for the years under appeal, less the amount ultimately paid to Kansas for all years under appeal;

    - Remit any refunds due to ratepayers with interest;

    - Notify the Commission of any court rulings issued prior to the Commission's final order in this proceeding; and

    - Make a compliance filing upon resolution of either the Minnesota property tax appeal or the Kansas ad valorem tax litigation. (Company, Department, ALJ)

(Note: These decision alternatives correspond to alternatives 3, 4 and 5 on the deliberation outline.)

Reference to the Record
Source: Wilde Direct, September 30, 2013, Page 10
Source: St. Pierre Direct, March 4, 2014, Page 21-26
Source: Lindell Direct, March 4, 2014, Page 11-13
Source: Wilde Rebuttal, April 15, 2014, Page 3-6
Source: St. Pierre Surrebuttal, May 7, 2014, Page 20-24
MERC Initial Post Hearing Brief, June 24, 2014, Pages 29-31
OAG Initial Post Hearing Brief, June 24, 2014, Pages 11-12
DOC Initial Post Hearing Brief, June 24, 2014, Pages 111-113
Source: MERC Post Hearing Brief, July 11, 2014, Pages 31-33
ALJ, Report, August 13, 2014, Page 59-61

Rate Case Expense

PUC Staff: Ann Schwieger

Amount of Test Year Rate Case Expense (Uncontested)

PUC Staff: Ann Schwieger

MERC and the Department are in agreement on the issue of test year rate case expense. The ALJ found that the inclusion of $1,482,130 for rate case expenses to be reasonable.

MERC forecasted total rate case expenses of $1,715,000 and proposed to amortize 87.7%, or $1,504,055, over a two-year period. The 87.7% reflects the removal of rate case expenses for MERC's non-utility business "ServiceChoice". The amortization results in test year expenses of $752,028. The types of expenses included are costs for MERC's cost of capital expert, legal fees, 3rd party requests such as Vertex and Itron, state agency and Administrative Law Judge fees, newspaper notices, and travel expenses. MERC believes that a two-year amortization is appropriate because as discussed above, MERC anticipates filing its next rate case with a 2016 proposed test year.

The Department noted that in MERC's last rate case (10-977) the test year included $10,500 of travel expenses but the Company did not incur any travel expenses related to that rate case. In this rate case, the Company has requested recovery of $25,000 of travel expenses. The Department recommended travel expenses of $21,925 (87.7% regulated business Xs $25,000 travel expense) be removed from the proposed test year rate case expenses.

The Department stated that because the Company has a travel and entertainment expense account included for recovery in this proceeding, there would be a double recovery if travel expenses were also included in rate case expenses.

MERC agreed with the Department's recommended adjustment of $21,925.

ALJ

In proposed finding 427, the ALJ concluded that inclusion of $1,482,130 in rate case expenses ($1,504,055 - $21,925) is reasonable.

Decision Alternative for Amount of Test Year Rate Case Expense

1. Reduce MERC's test year rate case expense by $21,925. (MERC, Department, ALJ)

(This decision alternative correspond to alternative 6 on the deliberation outline.)

Reference to Record
MERC, Exhibit 19, DeMerritt Direct, September 30, 2014, Page 27
DOC-DER, Exhibit 215 LaPlante Direct, March 4, 2014, Page 12-14
MERC, Exhibit 24, DeMerritt Rebuttal, April 15, 2014, Page 15

DOC-DER, Exhibit 216, LaPlante Surrebuttal, May 7, 2014, Page 2
DOC-DER, Initial Post Hearing Brief, June 24, 2014, Page 88
ALJ, Report, August 13, 2014, Page 64-66

Unamortized Rate Case Expense (Uncontested)

PUC Staff: Ann Schwieger

MERC and the Department are in agreement that unamortized rate case expenses and the associated taxes should be removed from rate base. The OAG also offered testimony on this matter.

The rate case expense in rate base is a regulatory asset that accrues when the Company incurs expenses attributable to the rate case prior to the revenue being collected from the ratepayers. MERC stated that it included rate case expense in rate base because incurring costs associated with a rate case is a cost of doing business as a regulated utility.

The Department considers the amount of rate case expenses included in MERC's test year rate base to be unamortized rate case expenses. Rate case costs are expenses, not assets to be amortized. A normalized level of rate case costs should be included in test year expenses. Rate case expenses should not be included as an asset in rate base and they should not be amortized. If the Commission were to allow rate case expense in rate base, the Company would be earning the allowed rate of return on the expense.

The Department recommended removal of unamortized rate case expense from the proposed test year's regulatory assets and liabilities amount. MERC accepted the Department's recommendation and proposed an additional adjustment to remove the associated deferred taxes from rate base. The Department agreed with MERC's proposal and made one additional recommendation to allocate the expense to the Minnesota jurisdiction.

The OAG also argued that it would be improper to include expenses as a rate base item because MERC has not requested deferred accounting for its rate case expenses. The OAG stated, "MERC has not requested deferral of rate case expenses and therefore it is not eligible to seek rate base treatment of this expense for rate recovery."[13]

The agreement excludes $1,312,704 and the related deferred taxes of $540,106 from MERC's rate base.

ALJ

The ALJ addressed unamortized rate case expenses and the related deferred taxes in proposed findings 477 through 479 as follows:

> 477. After a series of discussions between the parties, MERC agreed with the Department's proposed adjustment to remove from rate base the recovery of

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[13] OAG Ex. 153, Lindell Rebuttal at pp. 2.

unamortized rate case expense in the amount of $1,315,335 (regulatory asset Account 182513). MERC acknowledged that these costs are not prepaid costs.

478. MERC likewise proposed a corresponding additional adjustment to remove the deferred taxes that are associated with the unamortized rate case expense. Adjusting for the deferral that is properly allocable to MERC's Minnesota operations, this adjustment is $540,106.

479. Removing MERC's unamortized rate case expenses in the amount of $1,312,704, and its related deferred taxes $540,106, results in net reduction to rate base of $772,598.

Decision Alternative for Amount of Unamortized Rate Case Expense

1. Remove $1,312,704 of rate case expense and the related deferred taxes of $540,106 from MERC's proposed rate base. (MERC, Department, OAG, and ALJ)

(Note: This decision alternative corresponds to alternative 7 on the deliberation outline.)

Reference to Record
DOC-DOR, Exhibit 215, LaPlante Direct, March 4, 2014, Page 17-19
OAG, Exhibit 153, Lindell Rebuttal, April 15, 2014, Page 1-2
MERC, Exhibit 24, DeMerritt Rebuttal, April 15, 2014, Page 16-17
DOC-DOR, Exhibit 216, LaPlante Surrebuttal, May 7, 2014, Page 3-5
OAG Initial Post Hearing Brief, June 24, 2014, Page 19
DOC Initial Post Hearing Brief, June 24, 2014, Page 90
ALJ, Report, August 13, 2014, pp. 477-479

Period Over Which to Recover Rate Case Expenses (Contested)

PUC Staff: Ann Schwieger

Introduction

MERC and the Department are in agreement of the amount of test year rate case expense. MERC, the Department and the OAG are in agreement on the issue of unamortized rate case expense. MERC and the Department disagree on the period over which to amortize the rate case expense. The Department advocates a three year amortization period and MERC has requested the costs be amortized over a two year period. The ALJ supported MERC's two year request.

Department

The Department has proposed a three year amortization period for rate case expenses because estimating a reasonable amortization period is difficult. Many things can impact the Company's decision to file a rate case: inflation, cost of money, construction activity, customer usage and accounting changes are some examples. Utilities also consider the fact that rate cases are time consuming and costly in their decision to file a rate case.

The Department stated that it normally calculates an average time period between rate cases filed by the utility. The average for MERC is three years. Taking the average time between general rate cases is the normal method used for calculating the amortization period. This approach is reasonable because neither the utility nor the regulators can say for certain when the utility will file its next rate case, despite the utility's intention at this time. When doubt exists, the issue should be resolved in favor of the ratepayers. The Company has not shown a compelling reason to depart from the normal method for determining the amortization period.

MERC

MERC does not agree with the Departments recommendation to amortize rate case expenses over three years. The Company stated that the Department's analysis is based on a very narrow history of MERC rate cases filed, or the average of years in between the two previously filed rate cases. The Department calculated a simple average between the time of MERC's 2008 and 2010 rate cases (2 years) and MERC's 2010 and 2013 rate cases (3 years) to arrive at an average of 2.5 years. MERC stated that there is as much probability (50%) of MERC filing a rate case in 2015, using a 2016 test year, which would result in an average of 2.33 years between rate cases.

MERC argued that in this case, a two-year amortization period is appropriate because the Company is currently preparing for an increase in capital expenditures and anticipates the possibility that the Company may file a rate case in 2015 using a 2016 test year. The Company plans to undertake significant capital investments at a rate that would plausibly motivate it to make more frequent rate case filings.

MERC disagreed with the Department's argument that its proposed amortization period is inconsistent with the "normal method" for determining the amortization period. The Company stated the Commission has consistently taken into consideration both the historical trend and factual information regarding the likely timing of future rate cases to determine the appropriate amortization period to apply. The Department's recommendation of a three year amortization period inappropriately relies on simple averaging and is based on a very narrow history of MERC rate cases.

The Company agreed with the Department that estimating a reasonable amortization period is difficult because many things can impact a utility's decision to file a rate case. The Department rejected the Company's argument to take into consideration factual evidence that would support a two year amortization period in this case. Reasonable, prudently incurred rate case expenses are properly included in test year costs and built into rates for recovery from ratepayers. The Commission tries to set the amortization period to coincide with the time period between rate cases. It is important for these two time periods to match as closely as possible, to ensure that the utility recovers its authorized rate case costs without over-recovering them.

MERC agreed with the Department's statement with regard to the amortization period that "where doubt exists, it should be resolved in favor of the ratepayers." The Commission has exercised its discretion in past cases to ensure that if a utility delays filing a rate case beyond the amortization period set, the over-recovery of rate case expense be returned to ratepayers through a credit to the revenue requirement.

MERC stated Department's proposal could negatively impact MERC shareholders and likely will not accurately reflect MERC's actual costs.

ALJ

ALJ proposed findings 428 through 442.

In proposed finding 442, the ALJ found that a two-year amortization period is appropriate in this case. However, in the event that the Commission concludes that a three-year amortization period is more appropriate, the ALJ further recommended that the rate base balance of $257,985 be debited on an annual basis and amortization expenses credited for the same amount.

Exceptions and Clarifications

No party filed exceptions to ALJ findings 428 through 442. However, the Department stated that the Commission may wish to correct paragraphs 437, 439 and 442 of the ALJ Report as follows:

> 437. While MERC asserted that reliance upon the recent history of rate filings was not appropriate in this instance, it argued that if the Department's recommendation was adopted still other adjustments would be required. Specifically: (a) debiting the unamortized rate case balance of $257,985 on an annualized basis, and crediting amortization expense for the same amount; (b) use of a normalized level of rate case costs in test year expenses <u>for accounting purposes</u>, but one that is not an asset in rate base <u>for ratemaking purposes</u> such that the Company earns a return on this item; (c) a corresponding removal of $541,188 before allocation to Minnesota in deferred taxes from rate base; and (d) allocating only <u>$540,106, which is</u> the associated "Minnesota jurisdiction" share of these expenses.
>
> 439. The OAG-AUD agreed with the Department's recommendation <u>and MERC agreed with this adjustment</u>.
>
> 442. The Administrative Law Judge finds that a two-year amortization period is appropriate in this case. However, in the event that the Commission concludes that a three-year amortization period is more appropriate, the ALJ further recommends that the <u>unamortized</u> rate ~~base~~<u>case</u> balance of $257,985 be debited on an <u>annualized</u> ~~annual~~ basis and amortization expenses credited for the same amount.

Staff Analysis

The evidence in the record points to a greater probability of the Company filing a 2015 rate case using a 2016 test year. In MERC's initial testimony, the Company stated that it is currently preparing for a significant transmission line expansion project that would go into service in the last quarter of 2015. The Company is expecting to incur up to and possibly exceed $11.5 million in costs. The cost is significant to the Company whose annual construction budget is typically around $17 million.

MERC has also announced its intention to purchase the gas distribution assets of Interstate Power & Light (IPL). The acquisition is subject to Commission approval and is in the public comment stage. A decision is expected before the end of 2014. The cost of the assets is in the $9 million range. If approved, the Company anticipates that the revenues, costs, rate base and rate consolidation with IPL customers would be addressed in the Company's next rate case.

The Commission can prevent the risk of over-recovery if MERC does not file a rate case in two years by providing that any over-recovery is tracked and credited to the revenue requirement in MERC's next rate case.

As to the Department's proposed corrections to paragraphs 437, 439, and 442 of the ALJ's Report, staff believes the recommended corrections to paragraph 442 are the most important. MERC has agreed to remove unamortized rate case expenses from rate base, so the word "base" should be stricken and replaced with "case". Staff is somewhat unclear about the need for the ALJ's recommendation about the debits and credits MERC will be doing on its financial statements outside of this rate case.

Decision Alternatives for Amortization Period of Rate Case Expense

1. Approve a two year amortization period for rate case expenses and allow MERC to include $741,065 ($1,482,130 divided by 2 years) in test year rate case expenses. [MERC, ALJ] <u>or</u>

2. Approve a three year amortization period for rate case expenses and allow MERC to include $494,043 ($1,482,130 divided by three years) in test year rate case expenses. <u>and</u>

3. Allow MERC to debit the unamortized rate case balance of $257,985 on an annualized basis and amortization expenses credited for the same amount. [Staff Note: this is the difference between MERC's initially proposed annual expense of $752,028 and the amount the annual expense would be if amortized over three years, $494,043.] MERC, ALJ

4. Require MERC to track rate case expense recoveries exceeding the authorized test-year expense, for possible crediting against the revenue requirement in the next rate case.

(Note: These decision alternatives correspond to alternatives 8, 9, 10 and 11 on the deliberation outline.)

<u>Reference to Record</u>
MERC, Exhibit 19, DeMerritt Direct, September 30, 2013, Page 27
DOC-DOR, Exhibit 215, La Plante Direct, March 4, 2014, Page 15
MERC, Exhibit 24, DeMerritt Rebuttal, April 15, 2014, Page 15
DOC-DOR La Plante Direct, May 7, 2014, Page 8
MERC Initial Post Hearing Brief, June 24, 2014, Page 64-66
DOC Initial Post Hearing Brief, June 24, 2014, Page 88-89
MERC Post Hearing Reply, July 11, 2014, Page 23-25

ALJ, Report, August 13, 2014, Page 66-68
DOC Limited Exceptions to the ALJ Report, Page 31-32.

Regulatory Assets & Liabilities and Related Deferred Taxes

PUC Staff: Sundra Bender

Introduction

MERC initially included $19,642,806 of regulated assets and liabilities in its proposed test year rate base. This amount includes approximately $1,312,704 of unamortized rate case expenses which are discussed elsewhere in these briefing papers. Of the remaining 20 items totaling $18,330,102, Department witness Michelle St. Pierre recommended that 17 items totaling $11,281,942 be removed from rate base.[14] MERC and the Department disagree regarding this recommendation. The majority of the items and dollar amount are related to items involving employee benefits. The principal part of the disputed adjustment is the $16,587,916 amount in Account 182312, which is the balance in FAS 158; this balance represents the projected test-year funded status (plan assets minus obligations) of MERC's defined benefit pension as of a certain point in time.[15]

In rebuttal testimony, MERC agreed with the Department's recommendation as to the removal of two of the 17 accounts, one asset and one liability, with the net effect of increasing rate base by approximately $226,984 ($17,066 minus $244,050).[16] At the evidentiary hearing, MERC agreed to the removal of four more liability accounts pertaining to nonqualified employee benefit costs, with the effect of increasing rate base by approximately another $239,769.[17]

MERC and the Department also agreed that, if the Commission ultimately removes the assets and liabilities associated with the benefit plans, then the corresponding deferred taxes should be removed from rate base.[18] This adjustment is in the amount of $4,294,542 ($4,303,114 x 99.8 percent MN jurisdiction).[19]

Department

Specifically, in addition to its recommendation regarding the removal of unamortized rate case expenses from rate base, discussed elsewhere in these briefing papers, the Department recommended that the following regulatory assets and liabilities be removed from rate base:[20]

[14] DOC Ex. 219, St. Pierre Surrebuttal at 4, Table S1.
[15] DOC Ex. 217, St. Pierre Direct at 8–9; DOC Ex. 219, St. Pierre Surrebuttal at 8.
[16] DOC Ex. 219, St. Pierre Surrebuttal at 5; MERC Ex. 24, DeMerritt Rebuttal at 4.
[17] Evidentiary Hearing Transcript at 58.
[18] DOC Ex. 219, St. Pierre Surrebuttal at 9–10.
[19] DOC Ex. 219, St. Pierre Surrebuttal at 10–11.
[20] DOC Ex. 217, St. Pierre Direct at 11; DOC Ex. 218, St. Pierre Direct Attachments at (MAS-13); DOC Ex. 219, St. Pierre Surrebuttal at 3-4.

Regulatory Assets	Account Name		
128515	Post Retirement Life Asset		19,777
182312	Reg Asset-FAS 158		16,587,916
186390	Labor Loader		2,304
186591	Deferred Debit-LT A/R Arrearage		17,066
Regulatory Liabilities			
228200	Injuries & Damages Reserve		(217,943)
228210	Workers Comp Claim Reserve		(6,054)
228300	Def Cr-Sup Ret Select SERP		(163,731)
228305	Supple Remp Ret Plan SERP		(19,719)
228310	Pension Restoration		(53,763)
228315	Post Ret Health Care admin		(2,590,545)
228320	Post Ret Health Care NonAdmin		(749,060)
228331	Accr Pens Liab-CHI Retire Plan		(1,214,798)
242070	Current Pension Obligation		(20,572)
242072	Current Pension Restoration		(2,556)
254009	Reg Liab-Cost to Fwd-External		(255)
254400	Reg Liab Deferred Taxes		(39,556)
254450	Reg Liab-Derivatives		(244,050)
	Total Assets/Liabilities		11,304,461
	Minnesota Jurisdiction (99.8007934%)		11,281,942

Ms. St. Pierre stated in her direct testimony that MERC did not provide any regulatory support for including benefit assets and liabilities in rate base and the entire direct testimony provided by MERC on regulatory assets and liabilities consisted of MERC witness Christine Hans' statement as follows:

> The inclusion of the benefit assets and liabilities in rate base are a direct result of MERC's agreement with the OAG in Docket No. G007,011/GR-10-977 to adjust rate base for rate payer supplied funding. This adjustment had the direct effect of including the assets and liabilities associated with benefits into rate base. Therefore, MERC has followed that precedent in this current docket.

Ms. St. Pierre did not agree that all of MERC's assets and liabilities related to employee retirement benefits should be included in rate base. She stated in direct testimony that the trust plan assets may go up or down at a specific point in time depending upon funding and market conditions. The Department does not consider these temporary timing differences to be sufficient justification for including them in rate base. According to Ms. St. Pierre, MERC is already provided recovery for employee benefits in its proposed test-year income statement as well as a return on the employee benefit costs through the lead/lag study.[21]

Ms. St. Pierre also stated in her direct testimony that there were no changes in accounting standards that would suggest a change in how pension costs should be recovered in rates. While the Financial Accounting Standards Board issued Statement of Financial Accounting Standard (SFAS) 158 in 2006, this merely changed the balance sheet presentation for companies with defined benefit pension plans and cannot be used to justify including the over/under funded status of a pension plan in rates. Pension plans have always been over or under funded and, to Ms. St. Pierre's knowledge, these differences have not been included in rates.[22]

According to Ms. St. Pierre, the following regulatory assets and liability should not be removed from rate base:[23]

First, the regulatory asset in account 182351 - Purchase Accounting Effect on Benefits, should not be removed because the Commission authorized MERC, in Docket No. G007,011/M-06-1287, to create a regulatory asset for the pension and other post retirements acquired from Aquila.

Second, the regulatory asset in Account 182901, Cloquet Plant Amortization, should not be removed from rate base because the Commission accepted and adopted the Administrative Law Judges' findings on this issue in Docket No. G007,011/GR-10-977.

Third, the regulatory liability in Account 254391, Regulatory Liability – 2010 Health Care Legislation should not be removed because it was allowed in rate base in MERC's last rate case.

Ms. St. Pierre recommended that the Commission require MERC to reduce rate base by $11,281,942 for the Regulatory Assets and Liabilities adjustment.[24]

In her surrebuttal testimony, Ms. St. Pierre stated that MERC provided no support for including its proposed regulatory assets and liabilities in rate base, other than its agreement with the OAG[25] in its last rate case to adjust rate base for "ratepayer supplied funding". MERC did not cite to a Commission Order that authorized this approach. Second, the benefit assets and liabilities were not included in MERC's initial rate base in the last rate case even though the accounts were included in the Company's financial books and records. Third, Ms. St. Pierre stated, to her knowledge, the funding status of employee benefits (FAS 158, Account 182312) has not been included in the rate base of other Minnesota utilities. She also stated that the retirement benefits

[21] DOC Ex. 217, St. Pierre Direct at 9.
[22] DOC Ex. 217, St. Pierre Direct at 9-10.
[23] DOC Ex. 217, St. Pierre Direct at 10-11.
[24] DOC Ex. 217, St. Pierre Direct at 11 and (MAS-13).
[25] Staff notes that in its Reply Brief at page 15, the OAG stated that it has never supported including company-supplied funds in rate base, and MERC's attempt to attribute this position to the OAG is a misrepresentation. "The OAG's recommendation to *exclude* ratepayer-supplied funds from rate base in the 2010 rate case does not lend any support to MERC's argument to *include* a different source of funds in this case." ``

trust plan balance in FAS 158 is temporary, due to Company funding and financial market conditions, and should not be included in rate base.

Ms. St. Pierre stated that MERC is already provided recovery for employee benefits in the proposed test-year income statement, as well as a return on the employee benefit costs through the lead/lag study. The lead/lag study calculates a receivable or payable amount based on the related test-year expense that is added to rate base to earn a return. She further stated:[26]

> MERC's regulatory assets and liabilities are receivables and payables. Moreover, receivables and payables or accruals are included in test-year income statement expenses and MERC earns a return on these amounts through CWC [Cash Working Capital]. Thus, including receivables and payables in rate base in addition to CWC would provide a second or *double recovery of the return* on those amounts.

The Department does not oppose recovery of reasonable employee expenses, but concluded that it would not be reasonable to require MERC's ratepayers to pay a return to MERC on such amounts included in rate base.[27]

Ms. St. Pierre responded to Ms. Hans rebuttal testimony and explained that the Department's recommendation was not simply to exclude the $16,587,916 regulatory asset related to the FAS 158 adjustment, but to exclude other asset and liability balances as well. She concluded that it would not be reasonable to require MERC's ratepayers to pay a return to MERC on such amounts included in rate base.[28]

Ms. St. Pierre also stated that, since MERC is not requesting recovery of the expense portion of SERP and pension restoration non-qualified employee benefit costs, it follows that the related rate base portion (Accounts 228300, 228305, 228,310, 242072) should be removed from rate base. This is another reason to remove SERP and pension restoration amounts from rate base.[29]

Ms. St. Pierre explained that the balance in account 182312,-FAS 158 represents the projected test-year funded status (plan assets minus obligations) of MERC's defined benefit pension as of a certain point in time. She stated that the Company's pension plan is projected to be overfunded as of the end of the test year. "The $16,587,916 is an average 13-month balance."[30]

According to Ms. St. Pierre, the current rate case adjustment for the regulatory assets and liabilities is calculated differently than MERC's last rate case "ratepayer-supplied funding" adjustment. She stated:[31]

> In the last rate case, the $71,159 for the "ratepayer-supplied funding" adjustment was a net cumulative amount based on data from a five-year period 2007-2011.

[26] DOC Ex. 219, St. Pierre Surrebuttal at 6.
[27] Ibid at 7.
[28] DOC Ex., 219, St. Pierre Surrebuttal at 7.
[29] Ibid at 7-8.
[30] Ibid at 8.
[31] DOC Ex. 219, St. Pierre Surrebuttal at 9.

> In the current rate case, MERC proposed to increase the Minnesota jurisdictional rate base by $11,545,906 for the inclusion of net benefit assets (accounts 182515 and 182312) and liabilities (all of the 228 accounts and accounts 242070 and 242072) at one point in time, i.e., the 13-month average at the end of the test year. Thus, the current rate case calculation is not based on cumulative amounts for multiple years. Also, no adjustment was made to the related deferred tax in the prior rate case. [Footnote omitted.]

In her surrebuttal testimony, Ms. St. Pierre agreed with MERC that if the Commission ultimately removes the assets and liabilities associated with the benefit plans, then the corresponding deferred taxes, in the amount of $4,303,114 (total MERC) should also be removed from rate base.[32]

Ms. St. Pierre continued to recommend that the Commission require MERC to reduce rate base by $11,281,942 for the Minnesota jurisdictional Regulatory Assets and Liabilities. She also recommended that the corresponding Deferred Taxes Other than Plant in rate base should also be removed from rate base in the amount of $4,294,542 ($4,303,114 x 99.8 percent MN jurisdiction).[33]

At the evidentiary hearing, Ms. St. Pierre noted that a utility's rate base is not the same as a nonutility's balance sheet used for financial statement purposes. In her testimony at the hearing, she stated:[34]

> Generally rate base represents plant facilities and other investments required in supplying utility service to customers. The following are examples of differences between a utility's rate base and a nonutility's balance sheet.
>
> First, generally a utility's rate base does not include accounts receivables and accounts payables. For utility ratemaking those costs are reflected in the cash working capital, or CWC.
>
> Second, a utility's rate base includes cash working capital, and it's determined from a lead/lag study, where a balance sheet does not have that kind of study.
>
> Third, a utility includes in its rate base regulatory assets and liabilities, which reflect differences in expense and revenue recognition between ratemaking and Generally Accepted Accounting Principles, or GAAP, G-A-A-P.
>
> …
>
> … MERC and I disagree on the removal of 15 accounts within that regulatory assets and liabilities category of rate base, and I recommend that these items be removed for various reasons. And the largest one is regulatory asset called FAS 158, and that's account 182312, and it represents the funded status of MERC's

32 Ibid at 10.
33 Ibid at 10-11.
34 Evidentiary Hearing Transcript at 213-216.

> pension plan. And the funded status is the difference between the fair value of the plan's investments and its benefit obligations.
>
> The pension balance in FAS 158 is a temporary balance at one point in time, and it's due to the Company's current funding and financial market conditions. The Department doesn't consider temporary timing difference as sufficient reason or justification for rate base recovery.
>
> MERC proposes to recover employee benefits in its proposed test year income statement as well as earn a return on those costs that run through the lead/lag study. Including employee benefit accruals and – by including the employee benefit accruals in rate base in addition to the cash working capital, it would provide a second or double recovery of the return on those amounts. To my knowledge the funding status of employee benefits, or FAS 158, has not been included in rate base of other Minnesota utilities.
>
> The ratepayer supplied funding adjustment in MERC's last rate case was used as the Company's sole basis for including the benefit assets and liabilities in rate base in the current case. The calculation of the ratepayer supplied funding adjustment used a cumulative amount based on data from the five-year period, 2007 to 2011. In this case the inclusion of net benefit assets and liabilities are stated at one point in time. It's a projected 13-month average at the end of the test year.
>
> Further, in the last rate case no adjustment was made or agreed to remove the related deferred income tax, which has been proposed in this case if the regulatory assets and liabilities are removed.
>
> MERC is not requesting recovery of nonqualified employee benefits costs for pension restoration plan and for supplemental employee retirement plan, or SERP, S-E-R-P. So it follows that the related rate base accounts within 228300 that's one account, 228305, that's another account, 228310, and 242072 should be removed from rate base.

In its post hearing initial brief, the Department stated that:[35]

> [T]he employee pension is "externally funded," meaning that MERC pays pension expenses to a separate entity, a benefit trust, in an account maintained outside of the Company. The current trustee is BNY Mellon. Once the contributions are made, the Company no longer has use of the trust funds, nor of earnings on the trust funds, for its ordinary business purposes. Tr. at 58–59 (Hans). As a result, it is unreasonable for ratepayers to fund not only the pension expense, but also to treat the pension fund (FAS 158 Account 182312) as though it remained part of the Company's rate base upon which ratepayers must pay a return.

[35] DOC Initial Post Hearing Brief at 100.

In its post hearing reply brief (pp. 17-19), the Department stated:

> The MERC Initial Brief makes several mistaken, misleading or otherwise inappropriate assertions regarding the treatment of MERC's proposal on regulatory assets.
>
> First, at page 46, the MERC Initial Brief states, with respect to the FAS 158 Account:
>
>> Federal Energy Regulatory Commission ("FERC") account 182.3 (Other Regulatory Assets) allows for regulatory assets. It states, in part, that:
>>
>>> This account shall include the amounts ***of regulatory-created assets***, not includible in other accounts, resulting from the ***ratemaking actions*** of regulatory agencies.
>
> (emphasis added). This description of regulatory assets supports a finding that FAS 158 is ***not*** properly treated as a "regulatory asset" because it is not a ***"regulatory-created asset"*** and it is not the result of "***ratemaking actions*****["]** of its regulatory agency, the Commission. The Commission did not by regulation create the account, and it has taken no action on MERC's Account 182.3 (FAS 158).
>
> Not only is FAS 158 not a "regulatory-created asset," it is an asset that was created for business reasons, in that, as Ms. St. Pierre testified, FAS 158 reflects the projected test-year funded status of MERC's defined benefit pension. At the hearing, the Department explained that the cash working capital also does not include the regulatory asset amount for FAS 158 since FAS 158 is not an accrual. Cash working capital includes accrued expenses that are included in the income statement such as the Labor Loader (regulatory asset 186390).
>
> Third, the MERC Initial Brief makes a new and erroneous argument at page 50, where it states, "[e]ven though MERC cannot withdraw the prepaid pension asset or otherwise use it, the earnings on the asset are considered income to the utility". It is fundamentally incorrect for MERC to assert that pension earnings are earnings to the utility. Earnings returned from the pension's investments belong exclusively to the pension. As Ms. Hans acknowledged on cross examination at the evidentiary hearing, as an externally funded benefit trust, the pension fund and its earnings are not income or assets available to the utility; Ms. Hans stated that the contributions are funded to a trust "outside the company." The converse is also true: that is, the value of the pension fund at a given point in time is dependent on the pension's investment strategies, market conditions and past contributions, not MERC's earnings.
>
> Last, the MERC Initial Brief states at pages 50-51 that:

> … the Commission has authorized the inclusion of prepaid pension contributions in rate base ***as part of overall settlement.*** Specifically, in Xcel's 2010 rate case, Docket No. E002/GR-10-971, the Company introduced inclusion of a prepaid pension asset to become an addition to rate base because its actual cash contributions to the fund exceeded the claimed pension expense amount, ***which was included as part of a larger settlement***. Therefore, inclusion of the difference between cumulative funding and cumulative expense in rate base is reasonable, consistent with prior Commission decisions, and should be approved here.

> The operative word in the paragraph is "settlement." A settlement is not precedential, and does not support a finding that it is reasonable for the temporary pension balance to be included in rate base. Therefore, the circumstances in Xcel's rate case are not applicable to this rate case. [Footnotes omitted.]

MERC

In her direct testimony, MERC witness Christine Hans' stated:

> The inclusion of the benefit assets and liabilities in rate base are a direct result of MERC's agreement with the OAG in Docket No. G007,011/GR-10-977 to adjust rate base for rate payer supplied funding. This adjustment had the direct effect of including the assets and liabilities associated with benefits into rate base. Therefore, MERC has followed that precedent in this current docket.

In rebuttal testimony, in addition to the rate case expense regulatory asset discussed elsewhere in these briefing papers, MERC agreed that the following asset and liability should be removed from rate base:

Account No.	Name	Amount Asset (Liability)
186591	Account Receivable Arrearage[36]	$ 17,066
254450	Regulatory Liabilities Derivatives[37]	$(244,050)

In rebuttal testimony, MERC did not agree that any of its other proposed regulatory assets and liabilities, mostly related to benefits, should be removed. However, MERC stated that if the Commission removes the assets and liabilities associated with the benefit plans, then the corresponding deferred taxes also need to be removed from rate base.[38]

MERC disagreed with the Department's position on double recovery. According to Mr. DeMerritt, the regulatory assets and liabilities are not a function of benefit expenses, such as other working capital accounts. Benefit expenses are a function of the assets and liabilities.

[36] MERC Ex. 24, DeMerritt Rebuttal at 4.
[37] Ibid.
[38] MERC Ex. 24, DeMerritt Rebuttal at 4.

Typically, the greater the return on the assets, the lower the benefit expense MERC recognizes on its income statement. Mr. DeMerritt contrasted the benefits expenses with the accounts payable account, which is included in the lead/lag study, and stated:[39]

> Benefits assets and liabilities are more like construction costs than accounts payable. For benefits expenses, MERC must make an out-of-pocket cash expenditure to create the asset, but the asset is then used to earn a return and offset benefit costs.

MERC noted that while the benefit assets earn a return, this return is used to reduce benefit costs, not to repay shareholders for their prepayment of benefit costs.[40]

In her rebuttal testimony, Ms. Hans stated that the benefits related regulatory assets and liabilities represent the difference between the amounts contributed by MERC and the amounts recorded in expense by MERC.[41] Ms. Hans also stated that:[42]

> Although MERC did not include cumulative funding and cumulative expense in its initial filing in the prior rate case, MERC agreed to the inclusion in rate base. Thus, the difference between cumulative funding and cumulative expense was appropriately included in rate base in the last case and is being consistently included in the current case.

At the evidentiary hearing, Ms. Hans stated that:[43]

> MERC and the DOC disagree on the inclusion of Company supplied funds in rate base. …In the prior case MERC had expensed more than it contributed and a reduction to rate base was made. It is precisely the cumulative excess funding to the benefit plan that MERC proposes to include in rate base. Customers benefit from this excess funding via lower benefit cost.
>
> MERC has agreed to the removal of amounts pertaining to nonqualified employee benefit costs from rate base as proposed by DOC witness Ms. St. Pierre, credits of 163,731, 19,719, 53,763, and 2,556, for a total of 239,769. This results in an increase to rate base of 239,769.

In its initial post hearing brief, MERC stated that:[44]

> For benefits expenses, MERC makes an out-of-pocket cash expenditure to create the asset prior to any benefit expenses being recognized on the income statement, but the asset then earns a return and offsets benefit costs. MERC notes that while the benefit assets earn a return, this return is used to reduce benefit costs, not to

[39] MERC Ex. 24, DeMerritt Rebuttal at 3.
[40] Ibid at 4.
[41] MERC Ex. 27, Hans Rebuttal at 13 and 14.
[42] MERC Ex. 27, Hans Rebuttal at 15.
[43] Evidentiary Hearing Transcript at 56.
[44] MERC's Initial Post Hearing Brief at 52.

> repay shareholders for their prepayment of benefit costs. Instead, including these assets and liabilities in rate base is how shareholders earn a return on this funding activity. Therefore, inclusion of these amounts in rate base will not result in any double recovery as claimed by the Department. Inclusion of these amounts in rate base is reasonable, benefits ratepayers, and is consistent with prior Commission treatment. [Footnotes omitted.]

In its post hearing reply brief, MERC stated that:[45]

> The same five year period from MERC's last rate case is still included in the balance sheet in this case, but the balance sheet also contains activity reflected through December 31, 2014 (not just December 31, 2011 as in the last rate case). Thus, the only difference from MERC's last rate case is that the Company is using a thirteen-month average to value the Company's net benefit assets and liabilities. Inclusion of these regulatory assets and liabilities in rate base is reasonable, benefits ratepayers, and is consistent with prior Commission treatment.

MERC also stated that "[T]he pension assets and liabilities MERC has proposed to include in rate base are neither accounts receivable, nor accounts payable." The pension assets and liabilities MERC has proposed to include are not included in cash working capital. Inclusion of these amounts in rate base will not result in any double recovery as claimed by the Department.[46]

ALJ

Findings 467 through 501.

In proposed findings 467 and 468 the ALJ noted that MERC initially proposed to include $19,642,806 ($19,682,037 less $39,230 allocated to Michigan) as net regulatory assets in rate base and that the majority of the accounts, which also represent the most significant dollars, ($18,837,482 of the $19,682,037) are related to items involving employee benefits.

In proposed findings 471 through 476, the ALJ noted:

> 471. MERC and the Department are in agreement regarding the treatment of non-benefit regulatory assets and liabilities. (MERC's Post-Hearing Brief, at 47.)
>
> 472. Additionally, the Department concluded that Account 182901, Cloquet Plant Amortization, should not be removed from rate base. In MERC's last rate case, the Commission required MERC to include the regulatory asset Cloquet Plant Amortization (Account 182901) in rate base. (Ex. 217 at 10 (M. St. Pierre Direct).)

[45] MERC's Post Hearing Reply Brief at 38-39.
[46] Ibid at 39.

> 473. MERC and the Department likewise agreed that Account 186591 (Account Receivable Arrearage) was erroneously included in rate base. The Company concurred that a rate base reduction of $17,066 was appropriate. (Ex. 24 at 4 (S. DeMerrit Rebuttal); Ex. 217 at 10 (M. St. Pierre Direct).)
>
> 474. Further, MERC and the Department agreed that because derivative assets were excluded from rate base, Regulatory Liabilities-Derivatives, in the amount of $244,050 (Account 254450) should be excluded as well. (Ex. 24 at 4-5 (S. DeMerritt Rebuttal).)
>
> 475. Because of this exclusion, the same treatment should occur as to the associated deferred taxes in Account 254400 (Regulatory Liabilities Deferred Taxes). (Ex. 24 at 5 (S. DeMerritt Rebuttal); Evidentiary Hearing Transcript, at 216 (S. DeMerritt).)
>
> 476. Following these adjustments, MERC increased its proposed rate base amount by $226,984 ($17,066 - $244,050). (Ex. 219 at 5 (M. St. Pierre Surrebuttal).)

In proposed findings 477 through 479, the ALJ discussed MERC and the Department's agreement to remove unamortized rate case expenses in the amount of $1,312,704 and related deferred taxes of $540,106. This adjustment is discussed elsewhere in these briefing papers since it was a separate adjustment recommendation of the Department and not part of the 17 accounts discussed above.

In proposed finding 480, the ALJ noted that MERC agreed, during the evidentiary hearing, to remove the following four accounts pertaining to nonqualified employee benefit costs from rate base: Account 228300, Account 228305, Account 228310, and Account 242072. (Evidentiary Hearing Transcript at 56 (C. Hans); Ex. 27 at Schedule (CMH-4) (C. Hans Rebuttal); Ex. 217 at 7-11 (M. St. Pierre Direct).)

In proposed finding 481, the ALJ noted that the Department agreed that Account 254391 (Regulatory Liability – 2010 Health Care Legislation) was an element of the rate base in MERC's last rate case and should remain in MERC's rate base.

In proposed finding number 482, the ALJ noted that based upon adjustments agreed to during this proceeding, MERC has proposed to include $18,794,224 of regulatory assets and liabilities in rate base or a reduction of $848,582 ($19,642,806 - $18,794,224).

In proposed finding 483, the ALJ found that each of the stipulated adjustments is reasonable and appropriate.

In proposed findings 484 through 497 the ALJ found:

> 484. The remaining employee benefit related items, taken as a whole, represent the cumulative difference between the contributions funded by MERC to the

various benefit trusts and the actuarially calculated expense recognized by MERC.

485. During the period from 2012 through the 2014 test year, MERC contributed more to the pension and post-retirement benefit trusts than it recognized in expenses. This is the primary reason for its proposed rate base adjustment for employee benefits.

486. MERC argued that its proposal in this proceeding follows directly from the treatment of cumulative funding and cumulative expense in the Company's prior rate case. MERC noted that, although it did not include cumulative funding and cumulative expense in its initial filing in that case, at the urging of other parties, it included these sums in rate base.

487. Moreover, MERC maintains that because the contributions that it makes towards the various benefit plans are "out-of-pocket" expenditures, and provide value to ratepayers by reducing the future liabilities for benefit payments, these are expenditures as to which the company should rightfully earn a rate of return.

488. MERC and the Department disagreed on the inclusion of the benefit trust funds in rate base.

489. In the view of the Administrative Law Judge, the Department has the better of the two arguments. First, notwithstanding the practice agreed to in MERC's prior rate case, the multi-year averaging of cumulative amounts that occurred in that case is both different from what is proposed for this test year and not ideal.

490. It bears mentioning that the averaging of cumulative amounts, in the prior case, resulted in a reduction to the size of the rate base.

491. Second, generally, a utility's rate base does not include accounts receivable or accounts payable. These costs are reflected in the company's cash working capital.

492. To the extent that employee benefit expenses are reflected in cash working capital, MERC will earn a reasonable rate of return on these amounts.

493. Including employee benefit accruals in both cash working capital and a separate asset in rate base risks conferring a double recovery on those amounts.

494. Third, segregation of employee benefit amounts as a regulatory asset in rate base is not an accounting practice of any other Minnesota utility.

495. Fourth, the employee pension amounts are "externally funded." MERC pays pension expenses to a separate entity, a benefit trust, in favor of an account maintained outside of the Company. Once the contributions are made, the

> Company no longer has use of the trust funds, nor of earnings on the trust funds, for its ordinary business purposes.
>
> 496. Under such circumstances, it is not reasonable to regard the pension funds (FAS 158 Account 182312) as part of the Company's business assets – as to which ratepayers should pay a return.
>
> 497. Lastly, it does not appear that accepted accounting standards oblige the recovery of pension costs in the way urged by the Company. (Citations omitted).

In proposed finding 498, the ALJ recommended that the Commission require MERC to reduce rate base by $11,281,942 for the Regulatory Assets and Liabilities adjustment.

In proposed findings 499 through 501, the ALJ found that:

> 499. If the Commission removes the assets and liabilities associated with the benefits plans, then the corresponding deferred taxes should be removed from rate base.
>
> 500. The deferred tax adjustment amount is $4,294,542.
>
> 501. The net adjustment that reduces the rate base by $6,987,400.

Exceptions

MERC filed exceptions.

MERC argued that its proposal to include benefit assets and liabilities in the amount of $11,769,457 in rate base is consistent with the agreement it reached with the OAG, and approved by the Commission, in MERC's last rate case, Docket No. G007,011/GR-10-977.[47] According to MERC, these employee benefit-related items, taken as a whole, represent the cumulative difference between contributions funded by MERC to the various benefit trusts and the actuarially-calculated expense recognized by MERC.[48]

MERC disagreed with statements made by the ALJ regarding the benefit funds and proposed revisions to the conclusions stemming from those misstatements.

MERC disagreed with the ALJ's assessment in Finding 489 that "the multi-year averaging of cumulative amounts that occurred [in MERC's prior rate case] is both different from what is proposed for this test year and not ideal." MERC stated that there was no averaging in MERC's prior rate case.

MERC also disagreed with the ALJ's statements in findings 491-493 and stated:

[47] MERC Exceptions to ALJ Report at 3.
[48] MERC Exceptions to ALJ Report at 4.

- The pension assets and liabilities MERC has proposed to include in rate base are neither accounts receivable, nor accounts payable.

- The pension assets and liabilities MERC has proposed to include in rate base are not included in cash working capital.

- Thus, there is no risk of double recovery because MERC is not including employee benefit accruals in both cash working capital and rate base.

- Removing these amounts from rate base would result not in a double recovery for MERC, but, rather, would result in no recovery for MERC.

- Inclusion of these amounts in rate base is reasonable and is consistent with prior Commission treatment.

Additionally, MERC disagreed with the ALJ's conclusion in finding 496 that it is not reasonable to regard the pension funds as part of the Company's business assets.

MERC also disagreed that the ALJ's statement in finding 497 that "it does not appear that accepted accounting standards oblige the recovery of pension costs in the way urged by the Company," is a basis on which to reject MERC's proposed inclusion of thee regulatory assets and liabilities in rate base.

MERC proposed that the ALJ findings 489 through 501 be modified as follows:

> 489. In the view of the Administrative Law Judge, ~~the Department~~ MERC has the better of the two arguments. ~~First, notwithstanding the practice agreed to in MERC's prior rate case, the multi-year averaging of cumulative amounts that occurred in that case is both different from what is proposed for~~ MERC's proposed inclusion of the difference between cumulative funding and cumulative expense in this test year is appropriate and ~~not ideal~~ is consistent with the practice agreed to in MERC's prior rate case.
>
> 490. ~~It bears mentioning that the averaging of cumulative amounts, in the prior rate case, resulted in a reduction to the size of the rate base.~~ Inclusion of the difference between cumulative funding and cumulative expense in rate base is consistent with the treatment approved in MERC's prior rate case, Docket No. G007,011/GR-10-977.
>
> 491. ~~Second,~~ MERC has demonstrated that its regulatory assets and liabilities are not ~~generally, a utility's rate base does not include~~ accounts receivable or accounts payable. Nor are these costs ~~are~~ reflected in the company's cash working capital.
>
> 492. ~~To the extent that~~ Because MERC's employee benefit expenses are not reflected in cash working capital, MERC's regulatory assets and liabilities must

be included in rate base or MERC will not earn a reasonable rate of return on these amounts.

493. Because MERC does not include ~~Including~~ employee benefit accruals in both cash working capital and a separate asset in rate base, there is no risk~~s~~ of conferring a double recovery on those amounts.

494. Third, MERC has demonstrated that segregation of employee benefit amounts as a regulatory asset in rate base is ~~not an~~ the accounting practice of ~~any~~ at least one other Minnesota utility and is consistent with the agreement reached in MERC's last rate case.

495. Fourth, the employee pension amounts are "externally funded." MERC pays pension expenses to a separate entity, a benefit trust, in favor of an account maintained outside the Company. Although, once the contributions are made, the Company no longer has use of the trust funds, nor of earnings on the trust funds, for its ordinary business purposes, the earnings on the asset are considered income to the utility and reduce the overall revenue requirement, thereby benefitting ratepayers.

496. Under such circumstances, it is ~~not~~ reasonable to regard the pension funds (FAS 158 Account 182312) as part of the Company's business assets – ~~as to~~ for which ratepayers should pay a return.

497. Lastly, while ~~it does not appear that~~ accepted accounting standards may not oblige the recovery of pension costs in the way urged by the Company, nor do they forbid such recovery. Inclusion of the proposed regulatory assets and liabilities in rate base will not result in any double recovery, is reasonable, and is consistent with prior Commission treatment.

498. The Administrative Law Judge recommends that the Commission ~~require~~ approve MERC's proposal to ~~reduce rate base by~~ include ~~$11,281,942~~ $18,794,224 of ~~for the~~ Regulatory Assets and Liabilities in rate base ~~adjustment.~~

499. If the Commission adopts the Department's position and requires MERC to remove~~s~~ the assets and liabilities associated with the benefits plans, then the corresponding deferred taxes should be removed from rate base.

500. If the Commission adopts the Department's position, the deferred tax adjustment amount is $4,294,542.

501. If the Commission adopts the Department's position, the net adjustment ~~that~~ reduces the rate base by $6,987,400.

MERC also requested that, if the Commission ultimately removes the regulatory assets and liabilities associated with the benefit plans from rate base:

- The corresponding deferred taxes also be removed from rate base; and

- The Commission make clear in its Order that if, in the future, these assets and liabilities are a liability and would reduce rate base, that they be excluded from rate base as well.

Staff Comment

The Department described the FAS 158 asset as the projected test-year funded status (plan assets minus obligations) of MERC's defined benefit pension as of a certain point in time (an average 13-month balance). Staff notes that the value of a pension asset at any point in time does not necessarily reflect the actual out-of-pocket cash investment the Company has directed to the benefit because it also reflects investment returns – or losses. Also, the projected benefit obligation (liability) is not the cumulative pension expense recognized through the Income Statement, rather it is the present valuation of the future benefit obligation.

Staff agrees with the Department that the benefit assets in the trust fund are subject to change based on market changes.

Staff also agrees with the Department that test year employee benefit expenses are reflected in cash working capital through the lead/lag study. Staff disagrees with MERC's suggested modification to ALJ finding 492 because MERC's test year employee benefit <u>expenses</u> are reflected in cash working capital through the lead/lag study.

Staff believes MERC is correct that averaging of cumulative amounts did not occur in MERC's prior rate case. However, rather than adopting MERC's recommended modifications to ALJ findings 489 and 490, the Commission may wish to consider not adopting these two findings, or alternatively, striking the words "averaging of" from these two findings.

In MERC's last rate case, the OAG recommended an adjustment to rate base for "ratepayer supplied funds." MERC agreed to a relatively small adjustment in the amount of $71,159. Thus, the "ratepayer supplied funds" issue did not come to the Commission as a contested issue. Further, to staff's knowledge, the adjustment did not represent an average 13-month balance of plan assets minus obligations as has been described in this case.

Decision Alternatives

1. Adopt the ALJ's proposed findings 498 through 501 and require MERC to reduce rate base by $11,281,942 for the Regulatory Assets and Liabilities adjustment and its related deferred taxes of $4,294,542 for a net adjustment that reduces the rate base by $6,697,400. [DOC, ALJ] AND

2. Do not adopt ALJ findings 489 and 490. OR

3. Strike the words "averaging of" from ALJ findings 489 and 490. OR

4. Approve MERC's proposal to include $18,794,224 of Regulatory Assets and Liabilities in rate base. [MERC] (If the Commission selects this alternative, it may wish to adopt some of MERC's proposed modifications to ALJ findings 489 through 501.)

(Note: These decision alternatives correspond to alternatives 12 through 15 on the deliberation outline.)

Reference to the Record
MERC Ex. 4, Initial Filing Volume 3, Information Requirements, Document 2, Schedule b-6.
MERC Ex. 24, DeMerritt Rebuttal at pp. 3-5.
MERC Ex. 26, Hans Direct at pp. 12-13.
MERC Ex. 27, Hans Rebuttal at pp. 13-17, and (CMH-4), (CMH-5).
Evidentiary Hearing Transcript at pp. 23, 26-30, 56-59, 61-63, 98-100, 213-216, 225-227.
MERC Initial Post Hearing Brief at pp. 46-52.
MERC Reply Brief at pp. 38-42.
OAG Reply Brief at pp. 14-16.
DOC Ex. 217, St. Pierre Direct at pp. 7-11.
DOC Ex. 218, Attachments to St. Pierre Direct, MAS-13.
DOC Ex. 219, St. Pierre Surrebuttal at pp. 2-11.
DOC Initial Post Hearing Brief at pp. 95-101.
DOC Reply Brief at pp. 17-19.
ALJ Report at pp. 71-75.
MERC Clarifications and Exceptions to the ALJ Report at pp. 3-9.

Non-Fuel O&M Expense/Inflation

PUC Staff: Sundra Bender

The issue of the appropriate inflation adjustment and methodology to calculate base O&M expense is disputed between MERC and the OAG. No other party offered testimony on this issue.

MERC

To calculate its 2014 non-fuel operations and maintenance (O&M) expense, MERC used actual 2012 non-fuel O&M costs and applied inflation factors for 2013 and 2014 and then applied known and measurable (K&M) adjustments.[49] MERC witness Seth DeMerritt testified that MERC inflated actual 2012 nonfuel, non-labor O&M expenses by 1.708% in 2013 and 1.993% in 2014; and labor expenses by 2.6% in 2013 and 2.6% in 2014. The 2.6% labor inflation factor applied each year was the approved union contract wage increase for 2013 and 2014, and was used as a proxy for all employees wage increases in 2013 and 2014.[50] MERC used the simple average of Consumer Price Index – All Urban from the following sources to calculate the non-

[49] MERC Ex. 19, DeMerritt Direct at 9.
[50] MERC Ex. 19, DeMerritt Direct at 12.

labor inflation factors: Value Line, Global Insight, Moore Inflation Predictor, Energy Information Administration, and International Monetary Fund.[51] [Staff notes that the Moore Inflation Predictor and International Monetary Fund sources were not available for 2014 at the time MERC prepared its rate case. Thus, the simple average of the other three sources was used to determine the non-labor inflation factor for 2014.[52]] MERC's calculated inflation between 2012 and 2014 is 3.74% on non-labor and 5.27% on labor.[53]

MERC inflated total 2012 non-fuel O&M costs to 2014 by $1,995,654, of which approximately $1,994,592 was allocated to the Minnesota jurisdiction test year. (See MERC's Initial Filing Volume 3, Document 5, Schedule C-6 and Mr. DeMerritt's direct testimony at SSD-25.)

After applying the inflation factors, MERC then applied seventeen K&M adjustments, nine increases and eight decreases. Some of the specific K&M adjustments are disputed between MERC, the Department, and the OAG as discussed in greater detail in other sections of these briefing papers. MERC defined the K&M items to be any O&M cost item that increased (or decreased) at a rate greater than the rates of inflation described above, not including Gas Costs.[54]

Specifically, MERC adjusted non-fuel O&M expense for nine K&M increases associated with (1) increased billings from Integrys Business Support (IBS) customer relations related to increased third-party costs from MERC's billing vendor, Vertex, and implementation of the Integrys Customer Experience (ICE) program, (2) backfilling of vacant positions that existed at MERC during 2012, (3) uncollectible expense, (4) the Sewer Lateral project, (5) the Gate Station project, (6) the Mapping project, (7) the addition of seven employees at MERC, (8) depreciation and return cross charges from IBS for GMS software and ICE service, and (9) backfilling of vacant positions that existed at IBS during 2012.[55] MERC also adjusted non-fuel O&M expense for eight K&M decreases associated with (1) memberships, (2) 2 factor versus 1 factor General Allocator, (3) advertising, (4) Long Term Incentive Plans, Restricted Stock, and Stock Options, (5) 50% of economic development costs, (6) incentives, (7) the Vertex audit, and (8) benefits.

MERC does not agree with the OAG's recommended approach to calculating test year O&M expense and the recommendation to include only one year of inflation on top of MERC's 2012 historical year. Mr. DeMerritt states in his rebuttal testimony at page 21: [56]

> If MERC had intended to use 2013 as the test year for purposes of setting rates, MERC would have filed for a 2013 test year at a time that interim rates would have been in effect for 2013. Instead, MERC prepared its filing based on a 2014 test year, and based the O&M for the 2014 test year on a 2012 historical test year because 2012 was the most recent historical year available.

MERC also disagreed with OAG witness John Lindell's definition of known and measurable changes and Mr. DeMerritt stated that known and measurable events must occur after the historic

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[51] MERC Ex. 19, DeMerritt Direct at 12-13, SSD-19.
[52] MERC Ex. 19, DeMerrit Direct at SSD-19.
[53] MERC's Issues Matrix at 13.
[54] MERC Ex. 19, DeMerritt Direct at 14.
[55] Ibid.
[56] MERC Ex. 24, DeMerritt Rebuttat at 21-22.

test year. According to MERC, it identified known events [the previously listed nine increases and eight decreases] that will have a measurable impact on the 2014 test year.[57]

According to Mr. DeMerritt, using an average of external Consumer Price Index sources, and then adjusting for items that do not follow normal inflation, as proposed by MERC in this case, provides a non-biased and reasonable approach to calculating costs.

OAG

OAG witness John Lindell stated in his direct testimony that MERC's approach to developing its test year costs, which uses two years of inflation and two years of adjustments, produces unreasonable increases in costs for the test year. The total increase in non-fuel O&M from 2012 to the test year is 8.4% of which 4.6% is attributable to inflation.[58] Mr. Lindell disagreed with MERC's calculation of two years of inflation, and disagreed with MERC's use of external consumer price index inflation projections, stating that "Any external inflation projections, in particular consumer price index projections, would not be expected to reflect changes in MERC's O&M expenses."[59] Based on the three year average annual increase in MERC's historical non-fuel O&M expenses, the OAG recommended that 2012 non-fuel O&M expenses be inflated by a one year inflation factor of 2.2% (including both labor and non-labor inflation) to determine the test year level of non-fuel O&M expenses.

Mr. Lindell also testified that MERC's method of identifying what it claims is a known event over two years, 2013 and 2014, and roughly estimating the cost impact is inappropriate. According to Mr. Lindell, known and measurable changes are typically associated with a historical test year and identify specific measurable cost changes due to known events that occur during, or in some cases shortly after, the historical test year. "A measurable change requires that specific cost impacts can be identified with a fairly high level of specificity and are not simply rough estimates which is all that MERC has provided."[60]

In surrebuttal testimony, Mr. Lindell states that the OAG's proposal to use one year of inflation rather than two years produces a reasonable level of test year expenses. He further states:[61]

> The OAG does not accept MERC's two years of inflation and projections for known and measurable changes despite MERC's claim that doing so complies with Minnesota rules. The OAG continues to support one year of inflation of 2.2% because MERC's inflation is excessive and incorporates inflation factors derived from external sources. MERC has not shown that the inflation factors that it used are representative of the changes in MERC's non-fuel O&M costs from year to year. The OAG's inflation recommendation is based on MERC's actual historical cost changes and is therefore more reliable.

[57] MERC Ex. 24, DeMerritt Rebuttal at 22.
[58] OAG Ex. 151, Lindell Direct at 15.
[59] OAG Ex. 151, Lindell Direct at 17.
[60] OAG Ex. 151, Lindell Direct at 16.
[61] OAG Ex. 154, Lindell Surrebuttal at 7.

While Minnesota Rules technically permit MERC to claim that 2012 was its most recent fiscal year, rather than 2013, Mr. Lindell believes that this “contravenes the intent of the rule” because a large amount of 2013 data was available at the time MERC filed its rate case, which would limit the need for projections for all of 2013 as MERC has done.[62]

On page 6 of his surrebuttal testimony, Mr. Lindell stated that:

> Minn. Rule 7825.3100 defines the most recent fiscal year as the “… utility’s prior fiscal year unless a change in rates is filed within the last three months of the current fiscal year and at least nine months of historical data is available…”.

Mr. Lindell’s interpretation is that this definition was intended to limit speculation of cost increases over multiple years by requiring the most recent actual financial data to be filed.

ALJ

ALJ proposed findings 257 through 267.

In proposed findings 257 through 259, the ALJ described how MERC developed its test year non-fuel O&M expense and noted that the OAG had three principal critiques of MERC’s claims for recovery of Non-Fuel O&M expense: the breadth of MERC’s inflation factor; MERC’s characterization of certain project costs as “known and measureable;” and its selection of inflation rates.

In proposed findings 260 through 261, the ALJ addressed the OAG’s argument that MERC should not be able to include project cost increases for both 2013 and 2014 and the OAG’s recommendation that the Commission apply a one-year inflation factor to MERC’s historical O&M expenses. In proposed finding 261, the ALJ stated:

> 261. Because this approach unreasonably excludes costs relating to events that do have an impact on the 2014 test year, and should be recoverable, the OAG-AUD’s proposed inflation limitation is not appropriate.

In proposed findings 262 through 263, the ALJ addressed the OAG’s concern with MERC’s projection of costs for K&M projects undertaken after the historical test year and the OAG’s view that these projections are not sufficiently precise to be characterized as “known and measurable” costs. In proposed finding 263, the ALJ stated:

> 263. The Administrative Law Judge disagrees. The categories of costs identified by MERC will all have a measurable impact upon the 2014 test year. Moreover, the methodology employed by MERC in this case was identical to the methods it used in its 2008 and 2011 rate cases.

In proposed findings 266 through 267, the ALJ addressed the OAG’s argument that MERC’s use of external inflation projections was not appropriate and the OAG’s recommended use of an

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[62] OAG Ex. 154, Lindell Surrebuttal at 6.

"internal" inflation rate developed by the OAG based upon MERC's historical O&M cost changes, as well as the OAG's argument that, without such an adjustment, MERC will be relieved of the burden to improve operations and lower costs – the Company could safely assume that "costs continually rise nonstop…." In proposed finding 267, the ALJ stated:

> 267. The Administrative Law Judge disagrees. First, the changes in O&M cost components reflect MERC's efforts to balance service with new efficiencies. Moreover, the Company's method of modifying external inflation projections to account for fluctuations in bad debt expense produces results that are both superior and particularized to MERC's cost experience. Lastly, the inflation rate methodology used by MERC in this case was identical to the methods it used in its 2008 and 2011 rate cases.

Exceptions

While the OAG and the Department filed exceptions to some of the ALJ's findings with respect to specific proposed known and measurable adjustments, no party filed exceptions to ALJ proposed findings 257 through 267.

Staff Comment

Staff notes that MERC's Issues Matrix shows that an adjustment of $1,032,578 would be required to reflect the OAG's position on inflation. Although the calculation of this adjustment does not appear to be in the record, and it is unclear whether the OAG agrees with this amount, it appears to staff to be the difference between the total company test year inflation calculated by MERC of $1,995,655 and the test year inflation that would result from applying the OAG's recommended 2.2% inflation factor to 2012 non-fuel O&M of $43,776,226[63] ($43,776,226 x 2.2% = $963,077, and $1,995,655 - $963,077 = $1,032,578).

Decision Alternatives for Non-fuel O&M Expense/Inflation

1. Adopt the ALJ's findings and do not require MERC to adjust the methodology used to develop test year non-fuel O&M expense. [MERC, ALJ]

2. Allow MERC to inflate its 2012 non-fuel O&M by only 2.2%. [OAG]

   [If this alternative is selected, the Commission should clarify whether only the inflation adjustment should be adjusted (i.e., a decrease to test year non-fuel O&M expense of $1,032,578), or whether in addition to an inflation adjustment all (or some, such as those which were not separately challenged) non-fuel O&M known and measurable adjustments, both increases and decreases, should be eliminated.]

(Note: These decision alternatives correspond to alternatives 16 and 17 on the deliberation outline.)

[63] OAG Ex. 151, Lindell Direct at JJL-7, page 4.

Reference to the Record
MERC Ex. 4, Initial Filing Volume 3, Document 5, Schedule C-6.
MERC Ex. 19, DeMerritt Direct at pp. 9, 12-27, SSD-2 through SSD-19.
MERC Ex. 24, DeMerritt Rebuttal at pp. 19-25.
MERC Post Hearing Brief at pp. 33-36.
MERC Reply Brief at pp. 25-28.
OAG Ex. 151, Lindell Direct at pp. 14-21, JJL-7, JJL-8.
OAG Ex. 154, Lindell Surrebuttal at pp. 4-7.
OAG Post Hearing Brief at pp. 3-6, 9-11.
ALJ Report at pp. 41-43.

System Mapping Project

PUC Staff: Ann Schwieger

The amortization period over which to spread the costs of the system mapping project is contested between MERC and the Department. The Department is recommending the $330,000 cost be amortized over a three year period, with $110,000 built into the test year. The OAG offered testimony and agreed with the Department's recommendation to amortize the cost of the project over three years. The Company and the ALJ are recommending an amortization period of two years, or $165,000 built into the test year.

The Company requested an increase of $330,000 for a System Mapping Project in order to complete required Department of Transportation reporting which the Company is unable to do at this time due to incomplete or inaccurate mapping information. MERC has identified gaps within their mapping system that field personal utilize to locate lines, mange outages, determine flow modeling, and other critical infrastructure tasks. These errors have come from a number of map conversions as companies were acquired, sold and consolidated. To improve the quality and utilization of the mapping systems, the Company plans to verify the as built drawing to actual field data. MERC stated that it currently does not have the ability to verify age of pipe, materials, fittings, etc.

MERC anticipates that the mapping project will begin in February 2014 and end in December of 2014. The mapping project work will be completed by contractors rather than MERC employees due to the time commitment involved. MERC employees will oversee the project and project costs will be paid through an invoice to the contractor. The costs for the project are not eligible for capitalization because MERC is not installing new software. The Company is simply updating information that is not currently in its GIS mapping system.

The Department concluded that the Mapping Project is a one-time project to be completed by the end of the 2014 test year. The Department is recommending the project cost be levelized over three years because rates do not change between rate cases. The adjustment would result in an annual expense of $110,000 and a reduction to Distribution Expense as proposed by the Company of $220,000. The OAG supports the Department's recommended adjustment of amortizing the costs of the mapping project over three years.

MERC does not agree with the Department's recommendation. The Company argued that the Department's adjustment for a single item, with no consideration of future costs, sales, or capital requirements of other items would be punitive. Generally, it is understood that many expenses go up in the period between rate cases, and that some expenses may also go down. Expense levels are not adjusted until the next rate review, which determines whether the new proposed level of rates is reasonable on a going-forward basis, as retroactive ratemaking is not allowed. While the Mapping Project will only incur costs in 2014, the Department's proposal fails to consider how its proposed adjustment will impact MERC in future years. The Department is effectively proposing a single item ratemaking adjustment for 2015 and 2016 without consideration for any future increases in MERC's overall costs.

Further, as discussed above and in MERC's Initial Brief, MERC has already stated an intention to file a 2016 rate case; therefore, at a minimum, if the ALJ and the Commission determine the costs associated with the Mapping Project should be spread over multiple years, the appropriate period over which the adjustment should be spread is two years, not three.

The Department responded to MERC objection stating that the mapping project is an example of a classic conventional one-time project that should be levelized over three years. This is the same time period the Department has recommended amortization of MERC's rate case expenses. It would not be reasonable for the Commission to fail to levelize the cost over an amortization period.

The Department continued to recommend a three year amortization period but stated, "If the Commission approves a two-year amortization period for rate case expense, however, then the Department would agree with MERC that the costs should be spread over a shorter amortization period, of two years rather than three."

The ALJ found that amortizing the costs over two years and including $165,000 of the Mapping Project costs in the test year is appropriate.

Staff would like to add one item for the Commission to consider. For continuity, the period over which to allow the Company to recover Mapping Project costs should be the same as the period the Commission decides to allow recovery of the rate case expense.

Decision Alternatives for System Mapping Project

1. Amortize the cost of the system mapping project over three years at $110,000 per year and reduce the test year distribution expense by $220,000. (Department, OAG) <u>or</u>

2. Amortize the cost of the system mapping project over two years at $165,000 per year and reduce the test year distribution expense by $165,000. (MERC, ALJ)

(Note: These decision alternatives correspond to alternatives 18 and 19 on the deliberation outline.)

<u>Reference to Record</u>
MERC, Exhibit 19, DeMerritt Direct, September 30, 2013, Page 18

DOC-DER, Exhibit 217, St. Pierre Direct, March 4, 2014, Page 44
MERC, Exhibit 24, DeMerritt Rebuttal, April 15, 2014, Page 10
DOC-DER, Exhibit 219, St Pierre Surrebuttal, May 7, 2014, Page 41
Evidentiary Hearing Transcript, May 13, 2014, at 23-24, 37-39 & 44
MERC Initial Post Hearing Brief, June 24, 2014, Page 40
OAG, Initial Post Hearing Reply Brief, June 24, 2014, Page 130
DOC, Post Hearing Reply Brief, July 11, 2014, Page 16
ALJ, Report, August 13, 2014, Page 49-51

Travel, Entertainment, and Related Employee Expenses

PUC Staff: Ann Schwieger

Introduction

Pursuant to Minn. Stat. § 216B.16, subd. 17,[64] utilities are required to provide detailed information in their rate increase applications for any request to recover the cost of travel, entertainment, and related employee expenses.

MERC has provided documentation for $284,725 in the 2014 test year as Travel & Entertainment (T&E) expenses at the MERC level. The Department reviewed the Company's T&E expenses and concluded that $7,770 of T&E expenses did not appear to be reasonably

[64] Minn. Stat. § 216B.16, subd. 17. Travel, entertainment, and related employee expenses. (a) The commission may not allow as operating expenses a public utility's travel, entertainment, and related employee expenses that the commission deems unreasonable and unnecessary for the provision of utility service. In order to assist the commission in evaluating the travel, entertainment, and related employee expenses that may be allowed for ratemaking purposes, a public utility filing a general rate case petition shall include a schedule separately itemizing all travel, entertainment, and related employee expenses as specified by the commission, including but not limited to the following categories: (1) travel and lodging expenses; (2) food and beverage expenses; (3) recreational and entertainment expenses; (4) board of director-related expenses, including and separately itemizing all compensation and expense reimbursements; (5) expenses for the ten highest paid officers and employees, including and separately itemizing all compensation and expense reimbursements; (6) dues and expenses for memberships in organizations or clubs; (7) gift expenses; (8) expenses related to owned, leased, or chartered aircraft; and (9) lobbying expenses. (b) To comply with the requirements of paragraph (a), each applicable expense incurred in the most recently completed fiscal year must be itemized separately, and each itemization must include the date of the expense, the amount of the expense, the vendor name, and the business purpose of the expense. The separate itemization required by this paragraph may be provided using standard accounting reports already utilized by the utility involved in the rate case, in a written format or an electronic format that is acceptable to the commission. For expenses identified in response to paragraph (a), clauses (1) and (2), the utility shall disclose the total amounts for each expense category and provide separate itemization for those expenses incurred by or on behalf of any employee at the level of vice president or higher and for board members. The petitioning utility shall also provide a one-page summary of the total amounts for each expense category included in the petitioning utility's proposed test year. (c) Except as otherwise provided in this paragraph, data submitted to the commission under paragraph (a) are public data. The commission or an administrative law judge assigned to the case may treat the salary of one or more of the ten highest paid officers and employees, other than the five highest paid, as private data on individuals as defined in section 13.02, subdivision 12, or issue a protective order governing release of the salary, if the utility establishes that the competitive disadvantage to the utility that would result from release of the salary outweighs the public interest in access to the data. Access to the data by a government entity that is a party to the rate case must not be restricted.

related to Minnesota regulated utility operations. These items included gifts, golf outings and parties. The Company agreed with the Department's recommendation to remove the expenses which results in a $7,770 reduction to General & Administrative expenses. The ALJ concluded that this was reasonable. The OAG is not in agreement and recommended the Commission deny T&E expense of $569,450 and exclude dues totaling $63,245. The recommendation is due to the fact that MERC did not include schedules of the T&E expenses of MERC's service company affiliate IBS or justification of the dues.

The OAG's Objection

The Legislature passed a law that is codified in Minn. Stat. § 216B.16, subd. 17, which was added to the rate case filing requirements in 2010. This requirement broadly expanded the filing requirements to support recovery of T&E expenses. In addition, the Commission further clarified the filing requirements in Otter Tail Power's 2010 rate case. While the order clarifying T&E filing requirements for Otter Tail Power in its next rate case applied specifically to Otter Tail Power, other utilities should have taken notice and made changes to their own rate case filings to comply with the Commission's requirements to facilitate the review of T&E expenses.

The general requirement for allowing any cost recovery by a utility is that costs must be reasonable and necessary for the provision of utility service. Minn. Stat. § 216B.16, subd. 17, specifically prohibits the Commission from allowing recovery of any T&E expenses that are unreasonable and unnecessary. The statute includes the following requirements:

- separate itemization of nine specific categories of expenses including travel and lodging, food and beverages, recreational and entertainment, gift, and lobbying expenses;
- the itemization must identify the expenses in the most recently completed fiscal year and include the date of the expense, the vendor name, and the business purpose of the expense;
- for travel and lodging and food and beverage expenses the total amount for each category must be disclosed and separate itemization is required for these expenses for or on behalf of any employee at the level of vice-president or above and all board members; and
- the data is public data with limited exceptions regarding salaries for certain officers and employees.

In Otter Tail's 2010 rate case the Commission required that the information be provided in a searchable, sortable format and clearly describe the purpose of the expense. The Commission also required that the jurisdictional share of each expense be shown.

MERC has failed to comply with the filing requirements in many respects:

1.) MERC, like all utilities, is required by law to separately itemize the date, amount, vendor name, and business purpose of every travel and entertainment expense it seeks to recover. MERC has categorically failed to do so because MERC did not file separately itemized travel and entertainment expenses that were allocated to it by its affiliated service company, Integrys Business Solutions ("IBS"). The Department agreed that the expenses from IBS "should have been filed in the rate case." MERC stated that it will file the IBS travel and entertainment expenses in future rate cases. All travel and entertainment expenses related to IBS that were not itemized separately must be denied for failing to comply with statutory requirements. It is, however, impossible to quantify the total amount of travel and entertainment expenses from IBS because MERC has not provided that information. The OAG asked MERC to produce the data and MERC flatly refused. To overcome this problem, the OAG recommended using the value of $284,725 which is equal to MERC employees' reported travel and entertainment expenses as a proxy for the IBS allocated expenses that were not reported.

2.) Many of the expenses claimed by MERC are not supported by a business purpose demonstrating how the expenses are reasonable and necessary for the provision of utility services. For example, MERC reported expenses for several meals in Michigan from September 24 to 26, 2012 and indicated that the business purpose of these meals was "Supper in Michigan," "Lunch in Michigan," and "Breakfast in Michigan." These descriptions simply indicate that some employee of MERC ate a meal in Michigan. The descriptions provide no meaningful information about why the meals were reasonable and necessary for the provisions of utility services. Similarly, MERC describes the business purpose of many expenses as being "Meal less than $75. A notation that a meal cost less than $75 does not justify requiring ratepayers to reimburse the company. MERC has failed to satisfy the statutory requirements for itemizing travel and entertainment expenses and justifying their necessity. As such, the OAG has no reasonable alternative but to recommend that all travel and entertainment expenses in the amount of $284,725 be denied.

3.) MERC is also required by statute to separately itemize any dues and expenses for memberships in organizations or clubs. Just as with IBS travel and entertainment expense, MERC failed to itemize membership dues for several organizations. MERC included more than sixty thousand dollars in membership dues in its 2014 test year without separately itemizing them as the statute requires. Specifically, MERC failed to itemize $3,397 for membership in the Minnesota Chamber of Commerce; $3,496 for membership in the Edison Electric Institute; and $56,352 for membership in the American Gas Association. These expenses, in the amount of $63,245, should be excluded because they were not itemized as required by statute.

4.) The membership expenses should also be excluded because MERC has not established that the membership dues are beneficial for MERC's customers. Membership dues are recoverable "only to the extent that the activities they support directly benefit ratepayers." The Commission has excluded membership dues for the Chamber of Commerce in other rate cases. The Edison Electric Institute is an electric utility organization that provides no clear advantages for customers of a natural gas utility like MERC. The OAG raised these concerns in direct testimony, and no MERC witness has defended the Company's failure to itemize its membership expenses as required, or taken the opportunity to explain how membership in these organizations directly benefits ratepayers. The membership expenses should be excluded because MERC has not provided any evidence showing why they are reasonable.

In total, the OAG recommended that the Commission disallow $632,695 in travel and entertainment and dues expenses. MERC has failed in multiple ways to satisfy the legislature's requirement to separately itemize travel and entertainment expenses and to justify why membership dues directly benefit ratepayers. To permit MERC to recover those expenses would grant MERC recovery of expenses that violate a clear statutory instruction and encourage similar violations by other utilities in the future. For that reason, the OAG recommended that the Commission reject MERC's request to recover travel and entertainment expenses.

In addition, the OAG requested that the ALJ recommend, and the Commission approve, an order directing MERC to take the following steps in any future rate cases in order to comply with the travel and entertainment reporting requirements:

- Provide specific descriptions for the business purpose of expenses including the event or activity that the employee was attending or conducting;

- Include all travel and entertainment expenses, including travel and entertainment for employees who work for affiliates of MERC;

- Exclude all expenses incurred outside of Minnesota unless the description justifies an allocation to Minnesota; and

- Allocate only a portion of travel and entertainment expenses for items not specific to Minnesota, such as expenses related to Vertex.

MERC's Response to the OAG's Objection

1.) Contrary to the OAG's position, MERC has fully complied with the requirements of Minn. Stat.§ 216B.16, subd. 17 with respect to the Company's T&E expenses. The plain language of Minn. Stat.§ 216B.16, subd. 17, which applies reporting requirements only to "the utility" filing a rate case, does not require MERC to disclose the information requested by the OAG, which relates to MERC's service company, or affiliates of MERC.

2.) The membership dues were paid through IBS and they were not included as itemized expenses in MERC's informational filing. MERC provided the requested information regarding these expenses in response to information requests from the OAG. It is appropriate to include these dues in MERC's operating expense because MERC's membership in these organizations strengthens MERC's relationships with the communities it serves and ultimately benefits ratepayers. Specifically, membership dues to the Minnesota Chamber of Commerce allow MERC to work with Minnesota communities to help attract new business opportunities, strengthen the economy, and help create job growth. Additionally, while Minnesota ratepayers benefit from IBS' memberships in the Edison Electric Institute and the American Gas Association, MERC is not required by Minn. Stat. § 216B.16, subd. 17 to report these memberships, because both are associated with IBS and not MERC, the "utility" filing the rate case. In light of MERC's commitment to provide this information in future rate cases, MERC's recovery of these membership expenses is reasonable.

3.) Despite the OAG's objections, MERC and the Department are in full agreement about the appropriate amount of T&E expense. While the Department agreed with the OAG in surrebuttal testimony that MERC's T&E expenses allocated from its service company should have been filed in this rate case, the Department did not make any recommendation regarding that issue. MERC has agreed to provide additional information regarding all T&E expenses, including expenses related to its service company and employees who work for affiliates of MERC, in future rate case filings. MERC does not believe this additional information is required by the applicable statute, but will nonetheless provide the information to assist the Department and OAG in review of MERC's data.

MERC has met its obligations under Minn. Stat. § 216B.16, subd. 17, and has fully documented and justified its proposed test year T&E expense. MERC therefore respectfully requested that the Commission accept the agreement between MERC and the Department and find MERC's proposed T&E expense reasonable.

ALJ

ALJ proposed findings 321 and 686 through 700.

The ALJ decision supported MERC's position. In Decision Number 700, the ALJ found that, "Subject to the modifications agreed to by MERC, the Company's travel, entertainment and other employee expenses are reasonable and should be approved in this rate case."

Exceptions

The OAG took exception to the ALJ's recommendation on Travel and Entertainment expenses and his finding on membership dues. According to the OAG, the ALJ's description of the recommendations made by the OAG's witnesses and briefs is incomplete, and the ALJ's recommendation does not provide any consequence for MERC's failure to comply with the statutory requirements of Minn. Stat. § 216B.16, subd. 17.
The OAG recommended that ALJ finding 321, which states that MERC has excluded all organization membership dues from the 2014 proposed test year, be removed as it is factually inaccurate.

The OAG also recommended that the following additional findings be inserted following ALJ finding 696 to ensure that the OAG's reasoning is fairly represented in the ALJ's Report:

> <u>697. The OAG identified that MERC's travel and entertainment itemization was insufficient. MERC provided many business descriptions that did not provide any information about the purpose for the expense and that did not justify recovering the cost of the expense through rates. The OAG recommended that MERC's travel and entertainment expenses be denied recovery because MERC had violated statutory reporting requirements.</u>

> 698. The OAG also identified that MERC included $63,245 in membership dues in the test year, but did not itemize them as required by statute or demonstrate that they directly benefited ratepayers as required by Commission precedent. The OAG recommended that the membership dues be denied.

[Footnote omitted]

The OAG further recommended that ALJ finding 699 be modified as follows to reflect the fact that it is unreasonable for ratepayers to pay for travel and entertainment expenses that violate statutory reporting requirements:

> 699. Administrative Law Judge concludes that in future rate cases, travel and entertainment expenses that are allocated from MERC's service company must be submitted for review. Because MERC has not reported the level of these expenses, the ALJ recommends that the Commission use the reported level of travel and entertainment expenses as a reasonable proxy for those expenses that were unreported.

The OAG also recommended that ALJ finding 700 be modified as follows because it is not reasonable for ratepayers to be required to pay for MERC's travel and entertainment expenses:

> 700. The Administrative Law Judge finds that~~, subject to the modifications agreed to by MERC, the Company's travel,~~ entertainment and other employee expenses are not reasonable and should not be approved in this rate case. The Company did not provide sufficient business purposes in its itemization, completely failed to itemize travel and entertainment expenses related to affiliates, and failed to itemize membership dues. As a result, it is not reasonable for ratepayers to collect the expenses from ratepayers. The ALJ recommends that $284,725 in travel and entertainment expenses be denied. The ALJ recommends that membership dues in the amount of $63,245 be denied. The ALJ finds that a further $248,725 be excluded from recovery as a proxy for the travel and entertainment costs from MERC affiliates.

Decision Alternatives for Travel, Entertainment & Related Employee Expenses, and Membership Dues

1. Reduce Administrative and General Expenses by $7,770. (MERC, Department & ALJ)

2. Reduce Administrative and General Expenses by $632,695 ($569,450 for T&E plus $63,245 for membership dues). (OAG)

3. Require the Company in future rate case filings to meet the reporting requirements of Minn. Stat. § 216B.16, subd. 17 for all T&E Expenses, including expenses related to employees working for MERC affiliates. (MERC, Department, ALJ, OAG)

4. Require the Company in future rate case filings to allocate any costs not specific to Minnesota based on the allocation factor MERC files in its Direct Testimony and identify which costs have been allocated. (MERC, Department, ALJ, OAG)

(Note: These decision alternatives correspond to alternatives 20 through 23 on the deliberation outline.)

Reference to Record
Source: Initial Filing, September 30, 2013, Volume 3, Informational Document 14
Source: DeMerritt Direct, September 30 2013, Page 47-50
Source: LaPlante Direct, March 4, 2014, Pages 20-24 and LL-14
Source: DeMerritt Direct, April 15, 2014, Pages 17-18
Source: DeMerritt Surrebuttal, May 7, 2014, Page 2-4
Source: Lindell Surrebuttal, May 7, 2014, Page 7-9
Source: LaPlante Surrebuttal, May 7, 2014, Page 6-7
Source: Evidentiary Hearing Transcript, May 13, 2014, Page 25, at 138-139
Source: MERC Initial Post Hearing Brief, June 24, 2014, Pages 43-45
Source: OAG Initial Post Hearing Brief, June 24, 2014, Pages 15-18
Source: MERC Post Hearing Reply, July 11, 2014, Pages 35-37
Source: OAG Post Hearing Reply, July 11, 2014, Page 9-12
Source: ALJ, Report, August 13, 2014, Page 101-103

Taxes for NOL Carryforward

PUC Staff: Ann Schwieger

MERC has included a deferred tax asset (DTA) in its test year for a Net Operating Loss (NOL) carryforward of approximately $2.2 million. MERC has experienced several years of NOLs primarily due to the continual extension of the federal economic incentive allowing additional deductions to taxable income due to bonus depreciation. Bonus depreciation is an acceleration of tax depreciation based on a set percentage of the tax basis of the qualified property. Congress has enacted the bonus depreciation provision at various times in an effort to stimulate investment and create jobs. Bonus depreciation has allowed MERC to offset rate base and has kept rates lower than they otherwise would have been.

According to Mr. Wilde's direct testimony the DTA represents MERC's stand-alone operating income NOL that arose in 2012 and 2013 primarily due to bonus depreciation. It is projected that MERC will be in an income position in 2014 such that the DTA will reverse itself over the course of the year.

For federal tax purposes NOLs can be carried back and applied against taxable income for two years of carried forward for up to 20 years. According to Mr. Wilde, the determination if a standalone entity can carry a loss back or forward is determined by the consolidated group of company's federal taxable income position in the carryback and carryforward period. The parent corporation of MERC is Integrys. Like MERC, Integrys will generate a NOL in both 2012 and 2013. It is projected that the consolidated group will be in an income position in 2014 sufficient to absorb the NOLs generated in 2012 and 2013.

The OAG objected to MERC's proposed adjustment to recognize a deferred tax asset due to a NOL tax carryforward on the following grounds:

1) MERC's proposed adjustment is very rarely utilized to set rates and cannot be supported.
2) MERC is not the taxpayer that can claim a NOL. The parent company, Integrys is the taxpayer on behalf of the consolidated group of companies.
3) MERC has not demonstrated it actually generated an NOL and contributed to the NOL carry forward of the regulated utility companies in Integrys' consolidated group.
4) The IRS Private Letter Ruling (PLR) does not represent MERC's circumstances because it is a member of the consolidated group where the taxpayer in the PLR is a standalone company. Additionally, a PLR cannot be cited as precedent.
5) MERC will effectively utilize its NOL carry forward on the first day of 2014 and for that reason there is no economic basis to make an adjustment to reduce rate base by approximately $2.2 million as proposed by MERC.

MERC responded to the OAG's first objection and agreed that from a historical perspective it is uncommon for a regulated public utility that is a member of a federal consolidated group to be in the position of having a DTA NOL carryforward, the rarity of the occurrence does not support exclusion of the DTA when it does occur. The inclusion of the DTA in rate base is a proper reflection of MERC's costs and rate base on the measurement date. The inclusion of the DTA should be consistent with the normalization method of accounting adopted by the particular utility and allowed by the applicable regulatory commission as a necessary condition to remain in compliance with the federal tax normalization rules.

MERC disagreed with the OAG's claim that MERC is not the taxpayer that can claim a NOL and stated that Integrys, as a parent, acts as the agent for the federal consolidated group. Each subsidiary, including MERC, is considered a taxpayer that has the ability to generate a tax liability, as well as avail itself of other tax attributes such as a net operating loss carry forward. Section 1501 of the Internal Revenue Code ("Code") states "[a]n affiliated group of corporations shall, subject to the provisions of this chapter, have the privilege of making a consolidated return with respect to the income tax imposed by chapter 1 for the taxable year in lieu of separate returns." In accordance with Sections 1.1502 through 1.1506 of the Federal Tax Regulations, Integrys and its subsidiaries are jointly and severally liable for any resulting tax obligation of the consolidated group. This joint and several liability results from the tax obligations that would apply if the subsidiaries filed separate returns. According to Section 1.1502 of the Federal Tax Regulations, a net operating loss carry forward of a consolidated group is attributable to each member of the group based on that member's separate return loss.

According to the Company, MERC's response to OAG No. 128, included as Rebuttal_Exhibit_____(JRW-2) demonstrated MERC generated an NOL. On the schedule, the line labeled Depreciation reflects the tax over book difference related to claiming accelerated tax depreciation versus straight-line book depreciation. For 2012, claiming accelerated tax depreciation results in a $23,673,577 greater deduction than would have been allowed had MERC claimed straight-line book depreciation. For 2013, claiming accelerated tax depreciation results in a $22,630,741 greater deduction than would have been allowed had MERC claimed straight-line book depreciation. In both years, had MERC claimed straight-line book depreciation for regulation, versus using accelerated tax depreciation, then MERC would not have generated a net operating loss in either year.

The PLR referenced in MERC's Direct Testimony explains that in applying the tax normalization rules, a regulated public utility that generates a NOL by virtue of claiming accelerated tax depreciation must address the timing of when the NOL DTA is included in rates, and must address how the NOL DTA is to be valued. The PLR supports the "with' and "without" method MERC used to determine whether the NOL resulted from claiming accelerated tax depreciation. The PLR also provides citations to the relevant tax law and regulations to which a public utility like MERC should refer when developing a tax position and applying a normalization method of accounting. The PLR has been routinely referenced by tax experts that provide testimony in rates cases across the country. With respect to the valuation of NOLs, the Company stated it is not aware of any PLR's more closely aligned to MERC's facts.

The Company and the OAG agree that the PLR referenced by MERC cannot be cited as precedent to support the Company's position on tax normalization to the IRS. It has been the Company's experience that the IRS typically rules consistently with respect to past PLRs when presented with similar facts from another taxpayer. In practice, taxpayers do refer the IRS to previously issued PLR's when applicable, and the IRS does consider these prior rulings when reaching conclusions with respect to the positions of similarly-situated taxpayers.

However, MERC does not agree with the OAG's assertion that MERC will effectively utilize the NOL carry forward from the first day of 2014. The NOL DTA is not expected to be fully realized and will not benefit MERC until sometime during 2014. The cash benefit of the NOL DTA is earned during the year, and is not available to MERC as of the first day of the year. The NOL carry forward is applied to the tax obligations that would otherwise result from taxable income generated during 2014. MERC would not fully realize the benefit of the NOL DTA until the consolidated group accrued sufficient taxable income during 2014. The cash benefit would be achieved by applying the NOL DTA Carry forward against taxable income generated during 2014, resulting in a reduction in estimated tax payments during 2014.

The ALJ, in his Report on p. 59, in finding 378, stated that he found MERC's approach is reasonable and should be approved. OAG-AUD did not submit exception comments specific to this part of the ALJ's Report.

Staff Analysis

Normalization of the DTA is required in §168 of the Internal Revenue Code which states that accelerated cost recovery <u>will not apply</u> to "Certain public utility property if the taxpayer does not use a normalization method of accounting." Section §168 defines normalization rules as follows:

"In order to use a normalization method of accounting with respect to any public utility property…

(i) The taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and

(ii) If the amount allowable as a deduction under this section with respect to such property differs from the amount that would be allowable under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such differences."

Staff agrees that MERC is required by federal tax code to normalize its tax expense for regulatory purposes and recommends inclusion of the deferred tax asset in the test year.

Decision Alternatives

1. Approve MERC's Deferred Tax Asset of approximately $2.2 million for inclusion in the test year. (MERC, ALJ) or

2. Deny MERC's Deferred Tax Asset of approximately $2.2 million and require the Company to exclude the asset from the test year. (OAG-AUD)

(Note: These decision alternatives correspond to alternatives 24 and 25 on the deliberation outline.)

Reference to Record
MERC, Exhibit 36, Wilde Direct, September 30, 2013, Pages 3-7
OAG-AUD, Exhibit 151, Lindell Direct, March 4, 2014, Pages 7-11
MERC, Exhibit 37, Wilde Rebuttal, April 15, 2014, Pages 10-21
OAG-AUD, Exhibit 153, Lindell Surrebuttal, May 7, 2014, Pages 9-12
Evidentiary Hearing Transcript, May 13, 2014, at 96
OAG Initial Post Hearing Brief, June 24, 2014, Page 12-15
MERC Initial Post Hearing Brief, June 24, 2014, Page 31-33
MERC Post Hearing Reply, July 11, 2014, Page 33-35
OAG-AUD Post Hearing Reply, July 11, 2014, Page 12-13
ALJ Report, August 13, 2014, Page 57-59, Findings 369 - 378

IBS Customer Relations

Should ICE & Vertex costs be included in the same test year?

PUC Staff: Bob Brill

Introduction

Since the inception of MERC ownership of the Minnesota facilities, MERC's customer service, billing, and service call functions have been performed by a third party vendor, Vertex. Prior to MERC's ownership, Aquila used its centralized systems for these functions, and after the acquisition, ownership of Aquila's centralized systems remained with Aquila. Integrys Business Services' (IBS) system was unable to provide these services to MERC in a timely manner.

In this docket, MERC proposed to continue using Vertex's services until a consolidated billing system, Integrys Customer Experience (ICE), comes on-line in 2016. With the proposed ICE system, IBS will take over the customer relation functions and will bill its subsidiaries for the functions and will provide service to all of its utility companies in Minnesota, Wisconsin, and Michigan.

At issue between MERC and the OAG is the test year proposed cost recovery of $322,226 in ICE start-up O&M expenses incurred in addition to the Vertex customer service costs.

No other party offered testimony on this issue.

MERC

In its direct testimony, MERC included a $730,681 Known and Measurable (K&M) adjustment to increase its O&M expense for MERC's contract increases for Vertex and the proposed O&M adjustment for the ICE Project.[65]

In its rebuttal testimony, MERC did not agree with the OAG's recommended $823,990 adjustment to IBS Customer Relations costs. MERC's K&M adjustment of $730,681 was comprised of two components; a $408,455 O&M expense adjustment for Vertex contract increases and the remaining $322,226 O&M adjustment is associated with the ICE 2016 project. Therefore, Mr. DeMerritt stated in his rebuttal testimony:[66]

> [A]t a minimum, MERC believes the $408,455 cost increase associated with the Vertex contract is used and useful as discussed by Mr. Lindell, as Vertex is currently providing the same billing and customer care services in 2014 as it has historically.
>
> In addition, MERC continues to believe the ICE 2016 project costs are used and useful in the provision of utility services, and MERC notes that the DOC has not

[65] MERC Ex. 19, DeMerritt Direct at 15-16, SSD-2.
[66] MERC Ex. 24, DeMerritt Rebuttal at 25.

> raised a concern regarding these costs. However, contingent on regulatory approval from the Commission, MERC would be willing to defer ICE costs totaling $322,226 annually as a regulatory asset until MERC's next rate case, with recovery of the regulatory asset from customers over a reasonable period (e.g., 3 years) to commence once the in-house customer service and billing system has been implemented.

In its initial post hearing brief, MERC argued that MERC's costs associated with IBS Customer Relations Expense are used and useful and the corresponding adjustment is reasonable.[67] MERC argued that MERC's costs associated with Vertex are used and useful because Vertex is currently providing third party customer service functions to MERC customers. MERC also argued that the costs associated with the ICE 2016 Project are used and useful because it is a project that will unify the Integrys billing system and improve efficiency and productivity at MERC, and the estimated $322,226 increase associated with the ICE 2016 Project for 2014 should properly be included as a K&M adjustment to O&M expense.

MERC stated that:[68]

> In the event the ALJ determines the costs associated with the ICE 2016 Project are not used and useful, MERC has proposed to defer ICE costs totaling $322,226 annually as a regulatory asset until MERC's next rate case, with recovery of the regulatory asset from customers over a reasonable period (e.g., 3 years) to commence once the in-house customer service and billing system is implemented.

In its post hearing reply brief, MERC continued to argue that the ICE 2016 Project provides specific benefits to customers and these known expenses should be included in MERC's O&M expense calculation.[69]

MERC stated that:[70]

> If the Commission determines that the costs associated with the ICE 2016 Project are not to be recovered in the 2014 test year, the OAG, in its Initial Brief, has agreed that these costs may properly be deferred as a regulatory asset until MERC's next rate case. If these costs are not included for recovery in this proceeding, MERC has proposed to defer ICE costs totaling $322,226 annually as a regulatory asset until MERC's next rate case, with recovery of the regulatory asset from customers over a reasonable period (e.g., 3 years) to commence once the in-house customer service and billing system is implemented. The OAG objects to MERC's proposed amortization period, proposing that any decision on the appropriate amortization period be resolved during MERC's next rate case. MERC accepts this recommendation, as well as the OAG's recommendation that these expenses be subject to reasonableness review in a subsequent rate proceeding. If the Commission decides to exclude MERC's costs related to the

[67] MERC Initial Post Hearing Brief at 38.
[68] Ibid at 40.
[69] MERC Post Hearing Reply Brief at 26-27.
[70] MERC Post Hearing Reply Brief at 27-28.

> ICE 2016 Project in this rate case, MERC requests that the final Order in this proceeding state that these costs are approved for regulatory asset treatment in MERC's next rate case, to be recovered over an amortization period to be determined in MERC's next rate case. [Footnotes Omitted].

OAG

In its direct testimony, the OAG stated that Vertex currently provides third-party customer service functions to MERC. MERC is in the process of replacing Vertex with ICE and having IBS perform the customer service functions. The ICE project is just beginning and is not expected to be completed until 2016. The OAG stated that MERC's ICE project and the Vertex contract adjustments increased O&M expenses by $730,681 plus inflation of $217,986.[71]

Mr. Lindell stated:[72]

> One of the tenets of rate regulation is that cost recovery should only be allowed if it can be demonstrated that costs relate to labor and materials that are "used and useful" in the provision of utility service. MERC has started a multi-year project of replacing its Vertex customer relations services with its in-house customer relations services – ICE – which will not be completed until 2016. While developing its new ICE, MERC is requesting cost recovery for the ICE startup costs in 2014 in addition to the costs for its existing customer services provided by Vertex. MERC's customers should not be charged for services for both ICE and Vertex. Vertex costs are used and useful whereas ICE costs, at this time, are not.

Mr. Lindell recommended a test year IBS Customer Relations expense of $5,791,793, which includes a 2.2%[73] inflation adjustment to the 2012 customer relations expense rather than MERC's requested $6,615,783[74] which includes inflation and ICE project costs for a test year O&M adjustment of $823,990. The OAG stated that this amount should be removed from O&M expenses because the ICE project is not used and useful and is not scheduled to be in-service until 2016.

In its initial post hearing brief, the OAG stated that as long as several conditions are included, it has no objection to MERC's rebuttal proposal to exclude $322,226 from the test year related to the ICE 2016 project, and defer the costs as a regulatory asset until MERC's next rate case. Specifically, the OAG requested that the ALJ recommend, and the Commission approve, that these expenses be removed from the test year and treated as a regulatory asset only given the following conditions:[75]

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[71] OAG Ex. 151, Lindell Direct at 20; OAG Ex. 152, Schedules to Lindell Direct at Schedule JJL-8.
[72] See OAG Ex. 151, Lindell Direct at 21
[73] See OAG Ex. 151, Lindell Direct at Schedule JJL-8
[74] See MERC Ex. 19, DeMerritt Direct at Ex. SSD-2
[75] OAG Initial Post Hearing Brief at 6-7.

> First, MERC should not receive a return on expenses related to the ICE 2016 project as they are not used and useful at this time and MERC did not include the expenses as construction work in progress.
>
> Second, the OAG does not agree to the amortization period proposed by MERC, and recommends that any discussion of amortization period be resolved during MERC's next rate case.
>
> Third, while the OAG agrees that the costs should not be included in this rate case, the OAG does not waive any review of the reasonableness of the costs in MERC's next rate case.

Alternatively, the OAG requested that the ALJ and the Commission disallow $322,226 in ICE 2016 test year expenses.

In its post hearing reply brief, the OAG argued that, after the evidentiary hearing, and after the record closed, MERC has attempted to modify its position by arguing in its Initial Brief that "the ICE 2016 project is also used and useful."[76]

According to the OAG, MERC agreed to remove costs for the ICE 2016 project and it should be required to do so because the assets were not used and useful.[77] The OAG stated that the ALJ and the Commission should hold MERC to the position it initially agreed to: the ICE 2016 costs should be removed from O&M expenses and rate base until MERC's next general rate case filing.[78]

ALJ

ALJ proposed findings 268 through 276.

In proposed finding 275 the ALJ stated:

> 275. In the view of the Administrative Law Judge, the $408,455 in costs relating to the Vertex contract is both "used and useful." Vertex is now providing the same billing and customer relations services to MERC ratepayers that it has for many years.

In proposed finding 276, the ALJ recommended that the Commission accept MERC's conciliatory offer and permit designation of ICE-related costs as a regulatory asset and recovery of those costs from customers over a three-year period after the system has been successfully implemented.

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[76] OAG Post Hearing Reply Brief at 14.
[77] Ibid at 13.
[78] Ibid at 14.

OAG Exceptions

In its exceptions, OAG stated that, in MERC Rebuttal testimony, MERC offered to defer the ICE project costs as a regulatory asset until MERC's next rate case.[79] The ALJ recommended that the Commission accept MERC's offer, and the OAG agrees.[80]

The ALJ also recommended that the Commission permit recovery of the ICE 2016 costs over a three-year period after the system has been implemented.[81] The OAG disagreed with this recommendation, and believes that it is not supported by the record.

The OAG stated:

> The OAG's first concern is that the ALJ's finding appears to award MERC full recovery of the reported costs of $322,226 plus all costs that are incurred in the future. This would be unreasonable, as MERC has not yet satisfied its burden to demonstrate that the expenses were reasonable before requesting recovery. The OAG recommends that Finding 276 be modified to reflect that cost recovery will be determined at the time of MERC's next rate case.
>
> The OAG's second concern is that the ALJ's finding establishes a three-year period for recovery, even though there is no testimony in the record demonstrating that a three-year period is reasonable. It may be more reasonable to recover the costs over another period, such as the length of time that the ICE project will be useful. Even the company did not recommend a recovery period, in that it simply mentioned that one potential period could be three years. There is no record in this case to reach a reasoned conclusion as to the recovery period. [Footnotes Omitted]

The ALJ's recommendation to permit recovery over three years is not supported by the record, and the OAG recommends that Finding 276 be modified to reflect that the recovery period will be determined at the time of MERC's next rate case.

> 276. The Administrative Law Judge further recommends that the Commission accept MERC's conciliatory offer <u>to defer recovery of the ICE 2016 costs </u>and permit designation of ICE-related costs as a regulatory asset. <u>The ALJ recommends that the reasonableness of the ICE 2016 costs and the period for recovery be determined at the time of MERC's next rate case</u>~~. and recovery of those costs from customers over a three-year period after the system has been successfully implemented.~~

[79] MERC Ex. 24, DeMerritt Rebuttal at p. 24
[80] ALJ Report, Finding 276
[81] Id.

PUC Staff Comment

PUC staff believes that the $408,455 is reasonable and is related to the Vertex contract; and, therefore is used and useful during the test year and should be included in the test year O&M expenses.

PUC staff believes MERC's proposal to defer the test year $322,226 ICE costs and to treat the amount as a regulatory asset; receiving no cost recovery in this docket is reasonable. PUC staff is concerned that MERC failed to show the composition of what the costs are, i.e. labor, materials, and etc. PUC staff further believes that MERC should not be given the annual right to automatically record $322,226 as ICE costs, but should only record the actual expenses incurred, with cost recovery to be determined in MERC's next rate case.

Staff agrees with MERC's proposal to defer the test year $322,226 ICE expenses and to treat the amount as a regulatory asset; receiving no cost recovery in this docket; however, PUC Staff has several concerns regarding ICE costs as follows:

1. MERC originally proposed to book the $322,226 as a test year O&M expense. PUC staff believes MERC's original proposal is flawed for the following reasons:

    a. PUC staff believes that the $322,226 should have never been booked as an expense. GAAP clearly states that costs incurred while getting an asset ready for service should be capitalized; therefore, the proposed handling in the initial filing appears to be a GAAP violation. MERC has not provided in the record any explanation as to what type of expenses are reflected in its proposal, or any evidence that this amount should be considered an expense as opposed to an asset.

    b. PUC Staff believes that, since MERC disclosed ICE-related costs during rebuttal, ratepayers could have potentially been at risk of overpaying for the costs. If the $322,226 had not been provided and O&M expenses had been approved without adjustment, ratepayers would have annually paid for these ICE expenses. The ICE expenses of $322,226 would be recovered each year the rates are in effect.

    c. PUC Staff believes that MERC's auditors would have discovered MERC's O&M expense classification and would have suggested that MERC reclassify the O&M expense to a capital expenditure.

2. MERC has failed to show a cost breakdown, i.e. labor, materials, etc., for the $322,226; therefore, it is impossible for PUC staff to determine the reasonableness of the O&M expenses. PUC staff recommends that the Commission order MERC to provide, in its initial petition of its next rate case, a detailed breakdown of all the expenses it deferred as a regulatory asset.

For the reasons discussed above, PUC staff agrees with the OAG that the ICE costs should be reviewed for reasonableness in MERC's next rate case, therefore, the review rights should be reserved and no presumption of approval should be given in this docket.

Finally, since the ICE project's outcome is unknown at this time, PUC staff believes it is premature to set the amortization period at 3 years and, respectfully, disagrees with the ALJ's recommendation. Further, PUC staff agrees with the OAG position that the amortization period be determined in the next rate case. In MERC's post hearing reply brief it agreed that the ICE costs should be recovered over an amortization period to be determined in MERC's next rate case. The ALJ report findings 276 should be modified as stated by the above OAG discussion.

Decision Alternatives for IBS Customer Relations

1. Adopt the ALJ's findings and permit designation of ICE-related expenses as a regulatory asset until MERC's next rate case and permit recovery of those costs from customers over a three-year period after the system has been successfully implemented. [ALJ – MERC did not file exceptions.]

2. Adopt the OAG's suggested modification to ALJ finding 276 and require the expenses in the amount of $322,226 be removed from test year O&M expenses and treated as a regulatory asset with the following conditions: [OAG]

- The ICE 2016 project expenses shall not be included in rate base as the project is not used and useful at this time; MERC did not include the expenses as construction work in progress.
- Any discussion of amortization period shall be resolved during MERC's next rate case.
- The deferred expenses shall be subject to a reasonableness review in MERC's next rate case.

3. Adopt decision alternative 2 and, in addition, require MERC to record its actual IBS customer relations expense to the deferred account. Do not grant MERC the automatic right to annually record $322,226 in the deferred account. [PUC staff]

4. Adopt the OAG alternative position to disallow the $322,226 in ICE 2016 test year O&M expenses.

5. Find that both the Vertex contract and ICE 2016 project are currently used and useful and allow MERC to include the estimated $730,681 K&M increase associated with both in the test year expenses. [MERC Direct]

6. Find that IBS Customer Relations expense should be reduced by $823,990, reflecting the OAG's proposed inflation factor of 2.2% from 2012. [OAG Direct]

7. Order MERC to provide, in the initial filing of its next rate case, a detailed breakdown of all deferred ICE-related expenses. [PUC Staff]

(Note: These decision alternatives correspond to alternatives 26 through 32 on the deliberation outline.)

<u>Reference to the Record</u>
MERC Ex. 19, DeMerritt Direct at pp. 13-16, SSD-2, SSD-9.

MERC Ex. 24, DeMerritt Rebuttal at pp. 25.
MERC Initial Post Hearing Brief at pp. 38-40.
MERC Post Hearing Reply Brief at pp. 26-28.
Evidentiary Hearing Transcript at pp. 25
OAG Ex. 151, Lindell Direct at pp.19-21.
OAG Ex. 152, Schedules to Lindell Direct at Schedule JJL-8.
OAG Initial Post Hearing Brief at pp. 6-7.
OAG Post Hearing Reply Brief at pp. 13-14.
ALJ Report at pp. 44-45.

Depreciation and Return on Cross Charges from IBS

PUC Staff – Bob Brill/Sundra Bender

MERC

MERC made a known and measurable ("K&M") adjustment to its test year operating and maintenance ("O&M") expenses for depreciation and return on cross charges[82] related to two specific projects from Integrys Business Services (IBS); GMS Software (gas management system for energy trade, capture and risk management ("ETRM")) and Integrys Customer Experience (ICE) projects. The total O&M expense charged to MERC for these two projects in the test year is $280,470.[83]

The GMS project objective was to consolidate Integrys' five local gas distribution companies ("LDCs," including MERC) into a single gas management system for energy trade, capture and risk management. This will enhance operational efficiency for the companies' trading, risk management and accounting operations.

The primary benefit of having all Integrys gas utilities, including MERC, on a single ETRM platform is in providing consistent consolidated accounting and risk management. The GMS project software system went into service July 1, 2013.

The Integrys Customer Experience (ICE) project proposed to continue using Vertex's service while developing its consolidated billing system; scheduled for a 2016 in-service date. With the proposed ICE system, IBS will take over and will bill its subsidiaries for all current Vertex functions and will service all of its utility companies in Minnesota, Wisconsin, and Michigan. The ICE project is not expected to go in-service until 2016.

The increased depreciation and return costs are associated with ICE capital costs incurred with moving MERC's billing and reporting functions away from Vertex, and onto an IBS owned system, Open-C.[84]

[82] Refers to charges that are incurred and recorded on Integrys books that are allocated to and billed to the various Integrys subsidiaries
[83] MERC Ex. 19, DeMerritt Direct at 20 and Schedule (SSD-9).
[84] Ibid at pp. 20-21

MERC provided its IBS proposed depreciation and return increases in Exhibit SSD-9 which showed cost increases of $187,615 in 2013, $92,855 in 2014, and inflation of $3,740 for a total O&M expenses adjustment of $284,210.

In its rebuttal testimony, MERC stated that it does not agree that its K&M adjustment related to depreciation and return on assets cross charged from IBS lacks precision. The increase is due to two projects: GMS Software and the Integrys Customer Experience project.[85]

Further, MERC objected to the OAG definition of a known and measurable change, specifically, that the known event that can only be measured with a high degree of specificity if it occurs within a historical test year or shortly thereafter.

OAG

The OAG argued that although the IBS charges are purportedly for increases in depreciation and a return on assets, MERC did not identify the scope of the project costs, nor how these projects would be applicable to MERC's operations. Under such circumstances, it asserts that an allocation to MERC (or any of the Integrys subsidiaries) is inappropriate.[86]

In its surrebuttal testimony, the OAG stated that MERC and the OAG disagree on the concept of known and measureable changes in costs.[87]

ALJ

ALJ proposed findings 322 through 326.

In proposed finding 325, the ALJ disagreed with the OAG's argument that MERC did not identify the scope of the project costs, nor how these projects would be applicable to MERC's operations and an allocation to MERC is inappropriate, and stated: "The K&M adjustment related to depreciation and return on assets cross charged from IBS is sufficiently precise and set forth with detail like that for other K&M charges."

In proposed finding 326, the ALJ stated:

> 326. The Administrative Law Judge finds that MERC's K&M adjustment related to depreciation and return on assets cross charged from IBS of $280,470 should be approved for 2014.

Exceptions

No party filed exceptions to the ALJ findings 322 through 326.

[85] MERC Ex. 24, DeMerritt Rebuttal at 22-23.
[86] OAG Ex. 151, Lindell Direct at 16-17.
[87] OAG Ex.154, Lindell Surrebuttal with Errata, at 6.

Staff Comment

From the record, PUC staff is unable to determine the dollar amount associated with each project, GMS and ICE. In its direct testimony, MERC provides an explanation of what each project does and agrees with the ALJ's statement.

MERC does not provide any depreciation or return calculation support for the $280,470 or show how the amount is cross-billed (allocated) to the various Integrys subsidiaries by IBS.

PUC staff believes that the GMS project seems reasonable, but there is no support in the record for a proposed dollar amount. The ICE project is not in service and is not scheduled to be until 2016; therefore, cost recovery of this amount should not occur until the project goes in-service. If MERC were granted cost recovery of the ICE depreciation and return amount in O&M expenses, its customers would be paying for both the Vertex contract and the ICE project. PUC staff believes this would not be fair to MERC ratepayers. If IBS chooses to allocate cost to its MERC subsidiary, the cost recovery should come from MERC's shareholders, not its rate paying customers until the project goes in-service.

For these reasons and as stated in the IBS Customer Relations section of these staff briefing papers, PUC staff, respectfully, disagrees with the ALJ's recommendation. PUC staff believes that the ICE depreciation and return expenses allocated from IBS should receive deferral treatment similar to the IBS Customer Relations expenses.

Decision Alternatives for Depreciation and Return Cross Charges from IBS

1. Adopt the ALJ's findings and find that MERC's known and measurable adjustment related to depreciation and return on assets cross charged from IBS of $280,470 should be approved for 2014 and included in test year O&M expenses. [MERC, ALJ]

2. Find that the known and measurable adjustment related to depreciation and return on assets cross charged from IBS of $280,470 is not sufficiently supported, or precise enough, and require that the adjustment be removed from test year operating expenses. [OAG Direct - The OAG did not file exceptions to the ALJ Report on this issue.]

3. Find that the amount of the adjustment related to the GMS project should be allowed, but that the amount related to the ICE project should be removed as the ICE project has not been shown to be used and useful in the test year and will not be in-service until 2016. [If this alternative is selected, the Commission will need to require MERC to identify the amount of the expense related to each project]. [PUC staff]

(Note: These decision alternatives correspond to alternatives 33, 34 and 35 on the deliberation outline.)

<u>Reference to Record</u>
MERC Ex. 19, DeMerritt Direct at 20-21 and Schedule (SSD-9).
MERC Ex. 24, DeMerritt Rebuttal at 22-23.
OAG Ex. 151, Lindell Direct at 16-17.

OAG Ex. 154, Lindell Surrebuttal with Errata, at 4-7.
ALJ Report at pp. 51-52.

Employee Benefit Costs

PUC Staff: Sundra Bender

Reasonableness of Ratepayers paying 100% of MERC's pension obligation.
In its order in MERC's last rate case, Docket No. G007,011/GR-10-977, the Commission required that MERC, in its next rate case, "shall fully support the reasonableness of having ratepayers pay 100% of its pension obligation."

MERC witness, Noreen Cleary stated in her direct testimony at page 14, that:

> In 2008 the Company announced it was beginning an orderly transition from a defined benefit pension plan to a defined contribution plan. As part of that transition, the pension plan that has been offered to Administrative employees was closed to new entrants. At the same time, the Company, through the collective bargaining process, commenced negotiating the closing of the pension plan with the unions that represented a portion of MERC's work force. There are no longer any open pension plans at MERC. However, there are pension obligations that do remain in place for those employees who participated in the plans before they were closed. It is reasonable to continue to have those previously promised obligations recovered through rates as those obligations arose from a time when ratepayers were supportive of pension programs for public utility employees.

In her direct testimony at page 27, Department witness Michelle St. Pierre stated that:

> The Department has not advocated for any reductions in pensions to be paid to utility employees; instead, the Department has challenged the assumptions that utilities use in rate cases to estimate the amounts to charge to ratepayers in current rates to fund pensions in future years. For example, utilities often assume that the earning rates and discount rates on pension funds are too low, resulting in higher amounts to be paid today for the same level of pension benefits in the future… Given this focus, the Department does not take a position on MERC's change from a defined benefit to a defined contribution plan for union or non-union employees.

Test Year Employee Benefit and Pension Expenses

Introduction
The OAG disagrees with MERC's overall approach to developing its test year non-fuel O&M expenses (inflation and K&M adjustments). MERC and the Department have resolved several issues with respect to test year employee benefit expenses, but continue to disagree on the appropriate discount rates to be used in the calculation of test year pension and post-retirement

life expenses. The Department recommended the discount rate should be equal to the expected earnings rate.

Overview

MERC developed its 2014 test year employee benefits expenses in four categories:

1. 2014 costs that are not requested for rate recovery in 2014;

2. Forecasted 2014 costs that were estimated by MERC, including items based on preliminary results and trend information from MERC's actuary;

3. Forecasted 2014 costs that were determined by inflating 2012 actual costs; and

4. Forecasted 2014 costs that were determined through actuarial analysis.

The first category contains costs related to MERC's share of IBS's test year expenses related to non-qualified benefits. MERC is not requesting recovery of previously disallowed non-qualified benefits costs recorded in Accounts 926210-Pension Restoration Plan Expense, 926220-Supplemental Employee Retirement Plan (SERP), and 926300-Executive Deferred Compensation Employee Stock.[88] MERC is requesting recovery of the SERP amortization expense approved for recovery in Docket No. G-007,011/M-06-1287[89] and recorded in account 926220.[90] This expense is included in MERC's second category and is estimated to be the same as the 2012 amortization expense.

In addition to the SERP amortization expense, the second category contains MERC's dental benefits, medical benefits, and IBS benefits that are billed to MERC. Dental costs for 2014 were projected by applying to 2012 expenses a 5% annual inflation rate for 2013 and 4% annual inflation rate for 2014 based on preliminary renewal results and trend information received from MERC's actuary, Towers Watson. Medical benefits for 2014 were projected by applying an annual inflation rate of 7.50%. This inflation rate was also based on preliminary renewal results and trend information received from MERC's actuary. The total increase in dental and medical benefits was also impacted by the fact that MERC expects to employ more employees in 2014 compared to 2012. MERC estimated there would be no goal sharing or legacy Aquila defined contribution benefit costs for the test year. Also included in this second category is a significant projected increase in Defined Contribution Plan expense as a result of changes made to the pension plan benefit design.[91]

The third category contains a number of sub-accounts which included both expenses and reductions to expenses such as time away from work clearing, capitalized pensions and benefits, and non-utility loading (allocations). These sub-accounts (both positive and negative) were

[88] These non-qualified benefits were previously disallowed in MERC's last rate case, Docket No. G007,011/GR-10-977.

[89] The SERP amortization expense was allowed for recovery in MERC's last rate case.

[90] MERC Ex. 26, Hans Direct at 4, (CMH-1), (CMH-2).

[91] Ibid at 4-7, (CMH-1), (CMH-2).

projected by applying the labor inflation factors of 2.6% per year, resulting in an overall decrease from 2012 to 2014 of $23,295 or 5.3%.[92]

The fourth category, determined by actuarial analysis, contains employee defined-benefit pension expense, post retirement medical plan expense, and post retirement life plan expense.[93]

The Department did not recommend changes to any of MERC's proposed test year employee benefit expenses other than those determined by actuarial analysis.[94]

<u>Employee Benefit Expenses Determined by Actuarial Analysis (Defined benefit pension expense, post retirement medical plan expense, and post retirement life plan expense)</u>

MERC

There are four components of pension expense as determined in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 715-30 Defined Benefit Plans-Pension, which MERC follows for financial statement purposes. The four components are:

1. Service cost, which represents one-year's pro-rata share of the expected benefits earned during the year by current active employees;

2. Interest cost, which represents interest on the plan's benefit obligation (its liabilities) due to the passage of time;

3. Expected earnings on plan assets, which incorporates an assumption regarding the expected return on the assets held in the pension fund; and

4. Amortization of gains and losses, prior service costs, and any transitional amounts, which represents the amortization of various plan experiences that were different than anticipated by actuarial assumptions.

In order to calculate the annual pension expense under ASC 715-30, the actuary uses a number of assumptions including: Mortality tables, retirement rates for MERC, anticipated salary increases, expected return on plan assets, and discount rate. MERC initially used a rate of return of 8.00%, and a discount rate of 4.10% to derive the 2014 pension expense.[95]

In rebuttal testimony, Ms. Hans agreed with Department witness Michelle St. Pierre that the actuarially-determined costs should be based on the most recent and accurate data available. Ms. Hans proposed that MERC's initially projected test year pension and post retirement life expense be updated to reflect an updated actuarial analysis reflecting the plan asset values and discount rates as of December 31, 2013.[96] She proposed that the post-retirement medical expense be

[92] Ibid at 8, (CMH-1), (CMH-2).
[93] Ibid at 8-16, (CMH-1), (CMH-2).
[94] MERC Ex. 27, Hans Rebuttal at 4.
[95] MERC Ex. 26, Hans Direct at 11.
[96] MERC Ex. 27, Hans Rebuttal at 5, 7 and 12.

updated to reflect the plan asset values and discount rates as of March 1, 2014. The March 1, 2014 actuarial update was triggered as a result of a change to the plans.[97]

Ms. Hans stated that the discount rates in the updated analyses, which are used to calculate MERC's actual 2014 pension and OPEB costs are:[98]

Pension plan	4.95%	[99]	As of 12/31/13
Post-retirement medical			
Administrative plan	4.25%		As of 12/31/13
	4.05%		As of 03/01/14
Non-administrative plan	5.05%		As of 12/31/13
	4.80%		As of 03/01/14
Peoples Energy Medical	4.65%		As of 12/31/13
	4.45%		As of 03/01/14
Post-retirement life	4.80%		As of 12/31/13

Ms. Hans disagreed with the Department's recommendation to set the discount rate equal to the expected return on plan assets, or 8%.[100] Ms. Hans stated that the discount rate is intended to represent the rate at which benefit obligations, payable by the plan in the future, could be settled. The rates of return on high-quality fixed-income investments currently available and expected to be available during the period to maturity of the benefits are used in determining the discount rate. A separate discount rate is required to be calculated for each benefit plan.[101]

According to Ms. Hans, the assumptions used in the actuarial analysis are reviewed at least annually and are updated to reflect any market, plan design, or plan experience changes.

In its Initial Post Hearing Brief at page 58, MERC stated that:

> The Northern States Power - Minnesota ("NSPM") and Xcel Energy Services ("XES") pension plans in the Xcel Energy 2012 rate case, Docket No. E002/GR-12-961, which were cited by Ms. St. Pierre in support of the Department's position, are in no way similar or applicable to MERC's plan. The NSPM plan used an actuarial cost method called the Aggregate Cost Method ("ACM") to account for the costs of the plan, which is completely different than the methodology used by MERC and XES. Therefore, the comparison of the MERC and NSPM plans is wholly unreasonable. The calculations for the pension plan by XES accounted for its costs under FAS 87, which … is based on the present value of accrued benefits using corporate bond yields. [Foot-notes omitted.]

[97] Ibid.
[98] MERC Ex. 27 Hans Rebuttal at 6.
[99] At the evidentiary hearing, Ms. Hans corrected the 4.25% discount rate shown in her rebuttal testimony for the pension plan, to 4.95%. Evidentiary Hearing Transcript at 59-60.
[100] Ibid at 9.
[101] Ibid at 8.

MERC also stated that:[102]

> MERC's proposed employee benefit expense was determined based on the actuarial expense using generally accepted accounting principles ("GAAP") and most accurately reflects MERC's reasonable costs of doing business. Setting the discount rate equal to the expected return on plan assets, as proposed by the Department, would not accurately reflect MERC's reasonable costs of doing business and would not be representative of the specific facts and circumstances relative to MERC's pension and other employee benefit plans…

In its brief, MERC also responded to the Commission's recent decision in the CenterPoint Energy rate case, Docket No. G008/GR-13-316, and stated:

> As an alternative to its calculation, MERC believes that the five year historical average approach adopted by the Commission in CenterPoint Energy's most recent rate case, discussed above, would more reasonably reflect MERC's actual anticipated expense, as compared to the Department's arbitrary recommendation of using an eight percent discount rate based on expected return on plan assets.

Department

The Department did not recommend any adjustments to the first three categories of employee benefit expenses. However, with respect to the fourth category of benefit costs, Department witness Michelle St. Pierre stated she had concerns with the actuarial assumptions MERC used to calculate its test-year employee benefit costs and noted that actuarial calculations are done at a specific point in time and can vary significantly year to year. As a result, she stated, it is important to ensure that the utility: uses a current measurement date and plan asset value date to determine the investment or plan asset level, discounts future costs to today's rates, and uses a reasonable long term growth rate.[103] Specifically, Ms. St. Pierre was concerned that MERC's: [104]

- measurement date and plan asset values used in MERC's employee benefit calculations for the test year were outdated and may be too low and not reflect actual plan asset values as of December 31, 2013; and
- discount rates may be too low because the rates were less than the expected return on the plan assets.

Ms. St. Pierre explained that MERC's 2014 calculation of employee benefit costs was done in January of 2013, using plan asset values as of December 31, 2012 and then estimated for 2013 and 2014. However, she stated that after December 31, 2012 financial markets recovered significantly. She also referenced Xcel Energy's 2012 rate case (Docket No. E002/GR-12-961) in which the Department recommended, and the ALJ and Commission agreed, that the discount and expected return on plan assets used to determine test-year pension expense should be equal.

[102] MERC's Initial Post Hearing Brief at 53-54.
[103] DOC Ex. 217, St. Pierre Direct at 29.
[104] DOC Ex. 217, St. Pierre Direct at 30.

For the three actuarially determined benefits expenses (pension, post retirement medical, and post retirement life), Ms. St. Pierre initially recommended that (1) the plan asset values be updated to reflect the balance on December 31, 2013, and (2) that the test year expense determination be based on equal discount and long-term growth rates of 8%. To accomplish this, she recommended that the Commission require MERC to:

- Decrease test year Administrative and General (A&G) expense by $1,350,012 from $584,731 to $(765,281) for pension expense;
- Increase A&G expense by $10,260 from $472,077 to $482,337 for post retirement medical; and
- Increase A&G expense by $3,853 from a credit of $7,819 to a credit of $3,966 for post retirement life.

In her surrebuttal testimony, Ms. St. Pierre did not object to MERC's rebuttal proposal to update the plan asset values and discount rates for the post retirement medical plan as of March 1, 2014. She accepted MERC's updated post-retirement costs of $278,962 since the update provided the only available evidence that reflects the decrease in test-year costs due to the change in post-retirement medical plans. Ms. St. Pierre did not accept MERC's position to use a discount rate lower than the expected return on assets, which is included in MERC's revised post retirement medical expense, but, because actuarial updates are costly and the test-year post retirement costs are not high, she did not recommend that MERC be required to update the post-retirement costs for the Department's discount position in this case. Instead she changed her initial recommendation and recommended that the Commission require MERC to decrease post retirement medical expense by $140,720 for a total test year post retirement medical expense (MERC plus MERC's share of IBS allocated costs) of $332,675.[105]

Ms. St. Pierre continued to disagree with MERC over the discount rates to be used in calculating test year pension and post retirement life expenses. Ms. St. Pierre stated that it is unreasonable for ratemaking purposes to establish a level of test-year pension expense based on ASC 715.[106] She stated that:[107]

> The Commission's ratemaking function of establishing a reasonable level of pension expense in rates differs from the utilities' financial reporting and accounting prescribed under ASC 715. At a minimum, companies annually change the level (update) of pension expense based on the requirements in ASC 715, for its post-retirement medical plan change. Thus, if the level of pension expense in rates is determined based on ASC 715, it is highly unlikely that the pension expense going forward will be the same over time because of the frequent updates. Instead, the level of pension expense in rates should reflect the likely and reasonable expense going forward until the MERC's next rate case, which is the Department's position.

[105] DOC Ex. 219, St. Pierre Surrebuttal at 32-33 and (MAS-S-12).
[106] DOC Ex. 219, St. Pierre Surrebuttal at 26.
[107] DOC Ex. 219, St. Pierre Surrebuttal at 26-27.

According to Ms. St. Pierre, it is inappropriate for a regulated utility like MERC to use a discount rate that represents the rate at which benefit obligations, payable by the plan in the future, could be settled. She stated that:[108]

> MERC is highly unlikely to ever have to "settle" its pension benefits in the manner contemplated under ASC 715 and would be expected to inform the Commission about any such occurrence. Moreover, even if MERC were to go into financial distress, it is highly unlikely that the Company would be required to immediately settle its future pension benefits. In any event, MERC has not shown that it is likely to incur financial distress and be required to "settle" its pension benefits as contemplated under ASC 715.

In surrebuttal testimony, Ms. St. Pierre stated that the difference between Xcel Energy's pension plan and MERC's pension plan that Ms. Hans refers to is moot for ratemaking purposes. Ms. St. Pierre stated "both Xcel Energy pension plans used a discount rate in the calculation of the expense, which is the issue at hand."[109]

In its post hearing reply brief, the Department stated:

> In both the Xcel 2012 rate case and the instant case, a discount rate was used to calculate plan expense. Like the Xcel 2012 case, the Commission here should require a discount rate that is equal to the return on plan assets.

In conclusion, Ms. St. Pierre concluded that she and MERC agree on the post retirement medical expense adjustment proposed by MERC, and that she and MERC disagree on the pension and post retirement life expense issue.[110]

Ms. St. Pierre continued to recommend that the discount rate for pension expense and post retirement life be set equal to the expected return on assets of 8%, and continued to recommend that MERC be required to:

- Reduce test year pension expense by $1,350,012 from $584,731 to $(765,281); and
- Increase test year post retirement life expense by $3,853 from a credit of $7,819 to a credit of $3,966.

She also recommended that that Commission require MERC to decrease test year post retirement medical expense by $140,720 to reflect the March 1, 2014 actuarial update.

In its post hearing reply brief at page 20, the Department stated that MERC's initial brief's claim that GAAP "Most accurately reflects MERC's reasonable cost of doing business" is factually false, and not supported by the record. GAAP accounting assumes that the employer company determining an appropriate contribution must be able to immediately liquidate its position in its pension assets. According to the Department, this assumption is false with respect to regulated

[108] DOC Ex. 219, St. Pierre Surrebuttal at 28.
[109] DOC Ex. 219, St. Pierre Surrebuttal at 30.
[110] DOC Ex. 219, St. Pierre Surrebuttal at 33.

utilities and it does not accurately reflect MERC's reasonable costs of doing business as a regulated business.

The Department further stated that, applying GAAP principals in the circumstances of this MERC rate case would harm ratepayers by unreasonably increasing test year expenses. The Department stated:[111]

> Instead, setting the discount rate equal to the expected rate of return on the plan assets is representative of the specific facts and circumstances that MERC is a regulated utility, and that the Company has presented no evidence to show that the present value of the future pension fund, appropriately discounted should not be equal to the future value of the pension fund if the present value is subject to a reasonable rate of return on plan assets. There is no evidence to support a finding that these two valuations should not have the same growth/discount rate.

The Department also argued that MERC's proposed alternative (of a five year historical average approach such as was adopted by the Commission in CenterPoint Energy's most recent case), coming in its initial brief for the first time, has not been subject to discovery or investigation, nor has it been subject to cross examination. Thus, according to the Department, it is not appropriate for MERC to introduce a new proposal at this late stage in the proceeding.

The Department further argued that:

> In the present case, MERC presented absolutely no evidence that it must immediately "settle" its future pension obligation or that it is at imminent risk of having to do so. Thus, the record does not support selection of a test-year discount rate for ratemaking purposes that is based on an average of the past five "actual" *booked* discount rates (not actual annual pension expense) each of which were calculated *as if* MERC had been required to immediately settle its future pension obligation, which it did not do. MERC has not shown that it is reasonable for ratemaking purposes to overstate test-year pension expense by using such an average.
>
> The Department's recommendation to use the same discount rate and expected long-term growth rate assumptions for ratemaking purposes should be adopted because it assumes a reasonable discount rate and because it resolves doubt as to reasonableness in favor of consumers.

ALJ

ALJ proposed findings 204 through 256.

In proposed finding 213, the ALJ found that Accounts 228300, 228305, 228310 and 242072 should be removed from rate base. [Staff notes that the removal of these accounts from rate base is discussed in the Regulatory Assets and Liabilities section of these briefing papers.]

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[111] DOC Post Hearing Reply Brief at 20.

In proposed finding 221, the ALJ stated:

> 221. MERC's annual pension expense was $1,212,062 in 2012 and is projected to be $126,771 for 2014. Also included in pension expense for both 2012 and 2014 is an amortization of $474,223 per year as authorized by the Commission in Docket No. G-007,011/M-06-1287 on July 30, 2007 for pension and other post-retirement benefits acquired from Aquila.

In proposed finding 231 the ALJ found that the pension plan asset values and post-retirement life insurance plan asset values should be updated to reflect the balance on December 31, 2013, and the post-retirement medical plan costs should be updated from December 31, 2013 to March 1, 2014.

In proposed findings 239 through 240, the ALJ stated:

> 239. While the parties make a variety of different policy and financial arguments as to the best and most appropriate method of selecting the post-retirement plan discount rate, at the crux of the dispute is the parties' very different assessments of the near-term risks to the plan.
>
> 240. From MERC's perspective, the natural gas rates charged to its customers should reflect the costs of settling each post-retirement plan's "expected future benefit payments" and, being able to make that settlement in fairly short order…

In proposed finding 243, the ALJ stated:

> 243. Likewise, in its Initial Post Hearing Brief, MERC proposed use of a "five-year historical average" of earlier discount rates. Such an approach was approved by the Commission, after the close of the evidentiary hearing in this proceeding, *In the Matter of an Application by CenterPoint Energy Resources Corp.*

In proposed findings 245 through 251, the ALJ stated:

> 245. From the perspective of the Department, to the extent that any discount rate that is applied to the expected future benefit payments is less than the plan's rate of return, the amounts that are allocated to satisfy pension obligations will be overstated. As the Department reasons, MERC's proposed discount rates reflect both the amounts that are needed for near-term payouts to beneficiaries and a premium paid by ratepayers so that the Company could fully resolve all of its future pension liabilities, in a short time, if it needed to do so.
>
> 246. Arguing that the risk that MERC will need to resolve its long-term pension liabilities quickly, during the period that the new rates will be in effect, is quite low, the Department maintains that this added premium is unreasonable.

> 247. In the view of the Administrative Law Judge, the Department has both the better policy argument and the weaker case law. To the extent that MERC maintains that its rates should reflect contingent plans for near-term settlement of its pension obligations (or, alternatively, adding enough to the test-year pension amounts so that it would mirror the hoped-for performance of a pension portfolio with 70 percent equity stocks), those arguments do not persuade this tribunal. This is because having a discount rate that is lower than the overall rate of return on plan assets, means that the test year pension amounts will include the costs of covering a contingent, and speedy resolution of MERC's pension liabilities.
>
> 248. There is real doubt whether an otherwise reasonable ratepayer would pay (a good bit) more in order to address that contingency.
>
> 249. With that said, the facts and circumstances described in *In the Matter of an Application by CenterPoint Energy Resources Corp*, are indistinguishable from the case at bar. Use of a five-year historical average in this case will undoubtedly "buffer the effects" of any below-average discount rates and, in the Commission's view, "is more reasonable than a discount rate determined at a single point in time …."
>
> 250. Applying the principles announced in *CenterPoint*, the Administrative Law Judge concludes that use of a five-year historical average of discount rates is more appropriate than application of the expected rate of return on plan assets. This is because use of a single rate of return, as the discount rate, necessarily amounts to a "discount rate determined at a single point in time."
>
> 251. Because the Order in *CenterPoint* was issued after the close of the evidentiary hearing in this case, the parties themselves will need to confer as to the appropriate adjustments to test-year pension expenses.

In proposed finding 256, the ALJ found as follows:

> 256. The Administrative Law Judge finds that MERC's actuarial determined 2014 test year post-retirement medical plan expense and life insurance expense is reasonable and most accurately reflects the cost that MERC will incur during the test year.

Exceptions and Clarifications

MERC requested clarification of ALJ findings 251 and 254, and the Department filed exceptions and corrections.

MERC

MERC requested that finding 254 be clarified to correct the mischaracterization that the Department recommended that the Commission require MERC to reduce its rate base by $140,720. Specifically, MERC requested that the finding be clarified as follows:

> 254. Yet, because, as noted above, the Department and MERC do not agree as to the appropriate discount rate on such expenses, the Department also recommended that the Commission require MERC to reduce its ~~rate base~~ <u>expense</u> by $140,720.

Additionally, MERC explained that, in accordance with the ALJ's recommendation in finding 251, MERC submitted its proposed benefit expense for review by the Department and OAG on August 18, 2014. MERC stated that Based on subsequent conversations with the Department, MERC believes the Department is in agreement with respect to this calculation. Therefore, MERC requested that finding 251 be amended, as follows, to reflect the results of this calculation:

> 251. <u>Applying a five-year historical average of discount rates</u> <u>results in a reduction to pension expense of $668,392.</u> ~~Because the Order in CenterPoint was issued after the close of the evidentiary hearing in this case, the parties themselves will need to confer as to the appropriate adjustments to test-year pension expenses.~~

Department

The Department stated[112] that:

> The ALJ Report correctly found at paragraph 239 that "at the crux of the dispute is the parties' very different assessments of the near-term risks to the plan" upon which the actuarial assumptions used to set discount rates are based.

The Department also stated that it does not dispute GAAP's annual financial accounting. However, the Department continued to maintain that it is inappropriate for test year expenses of a regulated utility such as MERC to be based upon discount rates that are less than the expected rate of return on the plan's assets.

According to the Department, "The record does not support a determination that MERC is likely to go bankrupt or face a financial collapse that would require it to immediately 'settle' its future pension obligation before its next rate case or that it is at imminent risk of having to do so."[113]

The Department stated that:

> ... ASC 715 simply provides no reasonable basis for the Commission to use in deciding the reasonable discount rate for setting a regulated utility's pension expense in a retail ratemaking proceeding.[114]
>
> ... The only reason MERC's discount rate and expected long-term growth rate assumptions differ is because MERC applies to the discount rate an inapplicable

[112] Department Exceptions to the ALJ Report at 14.
[113] Department Exceptions to the ALJ's Report at 16.
[114] Ibid.

> accounting standard that increases the premium to be charged to ratepayers under which MERC is expected to "settle" at present its future pension obligation. It is unreasonable to assume for ratemaking purposes that MERC will face financial duress that would require such settlement, certainly not prior to MERC's next rate case.[115]

[T]he Commission is not required to follow GAAP's ASC 715 for ratemaking purposes, and it would be wrong and harmful to ratepayers in this circumstance to do so.[116]

This approach [a five-year historical average of earlier discount rates] results in a factually unsupported discount rate and inappropriately overstates test year expenses to be charged to ratepayers.[117]

The fact that the record was closed in the instant case when the Commission made an unexpected decision in the CenterPoint case is key given that the Commission's decision in the CenterPoint Rate Case is vastly different from the Commission's previous decision of the same contested issue in Xcel Energy's prior Rate Case (Docket No. E002/GR-12-961), for reasons that are not clear.[118]

If the Commission is inclined to set the discount rate at a lower level (such as the average of five years of discount rates that assume MERC would need to settle its pension assets in the near term), the Department requested that the Commission send this issue back to the ALJ to be developed further in this contested case proceeding to provide adequate and due process consistent with meeting the public interest.[119]

The Department recommended adoption of the ALJ Report subject to the following changes to paragraphs on discounting of future pension expenses. Specifically, the Department recommended the following changes to paragraphs 243, 245, 248 through 251, and 254 through 255 [footnotes omitted]:[120]

> 243. Likewise, in its Initial Post Hearing Brief, MERC proposed use of a "five-year historical average" of earlier discount rates. Such an approach was approved by the Commission, after the close of the evidentiary hearing in this proceeding, *In the Matter of an Application by CenterPoint Energy Resources Corp*.[121] <u>MERC's proposal has not been examined in discovery, vetted or subject to cross-examination in this proceeding on behalf of the public and thus is not ripe for consideration in this proceeding. An approach that averages five years of discount rates is inappropriate if each of those annual discount rates is based on the factually erroneous assumptions that MERC must immediately "settle" its pension obligation; averaging several of such erroneous rates continues to</u>

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[115] Department Exceptions to the ALJ's Report at 17.
[116] Department Exceptions to the ALJ's Report at 18.
[117] Department Exceptions to the ALJ's Report at 19.
[118] Department Exceptions to the ALJ's Report at 20.
[119] Department Exceptions to the ALJ's Report at 21-22.
[120] Department Exceptions to the ALJ's Report at 22-24.

overstate annual pension expense. This approach results in a factually unsupported discount rate and inappropriately overstates pension expense to be charged to ratepayers.

245. From the perspective of the Department, to the extent that any discount rate that is applied to the expected future benefit payments is less than the plan's rate of return, the amounts that are allocated to satisfy pension obligations will be overstated. As the Department reasons, MERC's proposed discount rates reflect both the amounts that are needed for near-term payouts to beneficiaries and a premium paid by ratepayers so that the Company could fully resolve all of its future pension liabilities, in a short time, if it needed to do so. MERC presented no evidence that it must immediately "settle" its future pension obligation or that it is at imminent risk of having to do so.

248. The Administrative Law Judge concludes that there is real doubt whether an otherwise reasonable ratepayer would pay (a good bit) more in order to address that contingency.[122] Where doubt exists, it should be resolved in favor of ratepayers. Minn. Stat. § 216B.03 (2012).

249. ~~With that said, the facts and circumstances described in *In the Matter of an Application by CenterPoint Energy Resources Corp*, are indistinguishable from the case at bar. Use of a five-year historical average in this case will undoubtedly "buffer the effects" of any below-average discount rates and, in the Commission's view, "is more reasonable than a discount rate determined at a single point in time …."[249]~~ The ALJ finds that it is not reasonable for the Commission to be guided by ASC 715 when deciding the reasonable discount rate when setting a regulated utility's pension expense in a retail ratemaking proceeding. The Commission is not required to follow GAAP's ASC 715 for ratemaking purposes, and it would be wrong in this circumstance to do so. The Department has demonstrated that its calculated 2014 test year pension benefit expense is reasonable and should be accepted in this rate case.

250. ~~Applying the principles announced in *CenterPoint*, the Administrative Law Judge concludes that use of a five-year historical average of discount rates is more appropriate than application of the expected rate of return on plan assets. This is because use of a single rate of return, as the discount rate, necessarily amounts to a "discount rate determined at a single point in time."[250]~~ The ALJ finds that MERC's test year pension expense should be decreased by $1,350,012 for 2014.

~~251. Because the Order in *CenterPoint* was issued after the close of the evidentiary hearing in this case, the parties themselves will need to confer as to the appropriate adjustments to test-year pension expenses.[251]~~

254. [Staff believes this should have been identified as 255 instead of 254.] With respect to MERC's proposed post retirement life insurance expense, the Department recommended~~s~~ an increase of $3,853 based on changing the discount rate to equal MERC's expected return on plan assets in its January 2014 update.

255. [Staff believes this should have been identified as 256 instead of 255.] The Administrative Law Judge finds that MERC's actuarial determined 2014 test year post-retirement medical plan expense and the Department's life insurance expense is reasonable and most accurately reflects the cost that MERC will incur during the test year.

On pages 30 through 31 of its exceptions to the ALJ Report, the Department identified what it characterized as typographical errors that appear in the ALJ Report, which the Commission may wish to correct. Most of those identified with respect to employee benefit costs relate to citations. However, two related to the text of findings as follows:

- P. 34, Finding 209 should read: The Department did recommend other adjustments to the 2014 employee benefit cost amounts (as determined by the actuarial analysis). The Department suggested revising both the measurement date and the plan asset value date, and changing the discount rate assumption so as to align it with the ~~expected return on plan assets~~ plan asset values as of December 31, 2013 .

- P. 41, Finding 254 should read: Yet, because, as noted above, the Department and MERC do not agree as to the appropriate discount rate on such expenses, the Department also recommended that the Commission require MERC to reduce its ~~rate base~~ base rates by $140,720.

Staff Comment

MERC agreed with the Department's recommendation to update the pension and post retirement life plan asset values to reflect the balance on December 31, 2013. The Department accepted MERC's proposal to update the post-retirement medical plan asset values and discount rates as of March 1, 2014. The expected return on plan assets used in the actuarial calculations for all three plans (pension, post-retirement medical, and post retirement life) is 8% and is not disputed.

The remaining controversy between MERC and the Department is the appropriate test year pension and post retirement life expenses to be included in the revenue requirement in this rate case. The Department believes the test year expenses should be calculated using a discount rate that is equal to the expected return on assets. MERC proposes that the test year expenses be calculated using the updated actuarial analyses with the discount rates supported by GAAP (which represent the rate at which benefit obligations, payable by the plan in the future, could be settled). The ALJ concluded that use of a five-year historical average of discount rates is more appropriate for determining pension expense than application of the expected rate of return on plan assets because "use of a single rate of return, as the discount rate, necessarily amounts to a 'discount rate determined at a single point in time.'" For test year life insurance expense (as well as post-retirement medical plan expense where no controversy appears to remain as to the test year amount), the ALJ found that MERC's actuarially determined test year expense is reasonable and most accurately reflects the cost that MERC will incur during the test year. Staff assumes the ALJ means the proposed updated calculations as of December 31, 2013 for post-retirement life insurance expense and as of March 1, 2014 for post-retirement medical plan expense.[123] However, staff notes that in its compliance filing to the ALJ's Report, MERC does not appear to have adjusted its originally proposed post retirement life insurance expense to reflect the updated December 31, 2013 calculations.

All of the positions that have been advocated or recommended, i.e. the Department's, MERC's rebuttal position, and the ALJ's, would require an adjustment to MERC's initially filed position. According to MERC, its rebuttal proposal results in a decrease of $651,524 from the expenses included in MERC's initial filing.[124] However, Staff notes that in rebuttal testimony, Ms. Hans increased the percentage of total IBS benefits expense allocated to MERC, thus effectively increasing all four categories of expenses allocated to MERC, including the three categories where there was no controversy. If the Commission adopts MERC's position on discount rates, it may wish to consider also requiring MERC to recalculate the adjustment using the original overall 4.1% allocation of IBS benefits expense to MERC instead of the 4.2% used in Rebuttal Exhibit____(CMH-2).

If the Commission adopts the ALJ's conclusion in proposed finding 250 that use of a five-year historical average of discount rates is more appropriate than application of the expected rate of return on plan assets and requires MERC to use such an average discount rate to calculate pension expense, for consistency it may wish to consider requiring MERC to also use five-year historical average discount rates in the calculation of post retirement medical and/or life insurance expenses. Staff notes this was not recommended by any party, or the ALJ. If it does require use of a five year average discount rate in the calculation of either, or both, of these test year expenses, it should consider modifying, or not adopting, proposed finding 256 accordingly.

If the Commission is interested in further exploring the use of discount rates in rate setting outside of a contested case proceeding, it may want to consider opening a generic inquiry into how the discount rate should be applied to future pension expenses for setting rates in Minnesota.

Clarifications/Corrections

Both MERC and the Department recommended clarifying ALJ finding 254. The Department's recommended adjustment to reflect the March 1, 2014 calculations for the post-retirement medical plan expense was to reduce MERC's initially proposed test year operating expenses by $140,720. Staff believes MERC's recommended modification to replace the words "rate base" with "expense" is clearer, but either party's recommended modification would suffice.

MERC also requested that finding 251 be amended to reflect the results of its calculation of pension expense using a five-year historical average of discount rates. If the Commission adopts the ALJ's recommendation to use a five-year historical average of discount rates to calculate

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[123] In proposed finding 231, the ALJ found "that the pension plan asset values and post-retirement life insurance plan asset values should be updated to reflect the balance on December 31, 2013. The post-retirement medical plan costs should be updated from December 31, 2013 to March 1, 2014."

[124] MERC Ex. 27, Hans Rebuttal at 17.

test-year pension expense, rather than adopting the Department's recommendation that the Commission send this issue back to the ALJ to be developed further, it may wish to consider adopting MERC's suggested modification. However, staff notes that MERC's proposed adjustment number has not been vetted in the record of this proceeding.

As noted above, the Department also suggested correcting finding 209. It is unclear to staff whether this recommended correction is necessary and possibly depends on whether the Commission decides to adopt a discount rate equal to the expected return on plan assets. The Department's recommended adjustment to the discount rate assumptions was to make the discount rate equal to the expected return on plan assets.

If the Commission adopts ALJ finding 256, it may wish to (1) clarify that it is, respectively, the March 1, 2014 and December 31, 2013 post retirement medical plan and post retirement life insurance plan actuarially determined 2014 test year expenses, and (2) require MERC to adjust both its initially proposed post retirement medical plan and post retirement life insurance plan test year expenses.

Decision Alternatives on Employee Benefit Expenses

1. Adopt MERC's agreement with the Department to update the measurement date for the plan asset values for pension expense and post-retirement life expense to December 31, 2013. [DOC, MERC, ALJ]

2. Adopt MERC's proposal, accepted by the Department, to use the updated March 1, 2014 plan asset values in the calculation of the test year post-retirement medical expense. [MERC, ALJ, accepted by DOC].

3. Adopt MERC's rebuttal proposal to use the updated December 31, 2013 plan asset values and discount rates in the calculation of the test year pension and post-retirement life expense, and the updated March 1, 2014 plan asset values and discount rates in the calculation of test year medical plan expense, and:

    - Allow MERC to reduce its initially proposed test year pension, post retirement, and medical plan expenses by a combined total of $651,524. [MERC's rebuttal position.] OR

    - Require MERC to recalculate the reduction to its initially proposed test year expenses to retain the original overall 4.1% allocation of total IBS benefit expenses to MERC [Staff believes this would change the reduction to approximately $677,751, a difference of about $26,227].

4. Adopt some, or all, of the Department's recommended modifications to the ALJ findings and require MERC to:

    - Reduce test year pension expense by $1,350,012 from $584,731 to $(765,281); [DOC]

- Increase test year post retirement life expense by $3,853 from a credit of $7,819 to a credit of $3,966; [DOC] and
- Decrease test year post retirement medical expense by $140,720 [adjustment amount appears to be accepted by DOC, MERC, ALJ].

5. If the Commission is considering setting the discount rate at a lower level, adopt the Department's request and send this issue back to the ALJ to be developed further in this contested case proceeding. [If the Commission selects this alternative, it may wish to clarify whether it is sending the discount rate issue back to contested case proceeding for both pension and post-retirement life expense, or just for pension expense.]

6. For test year pension expense, adopt the ALJ's finding 250 and require MERC to calculate test year pension expense using a discount rate equal to the five-year historical average of discount rates. [ALJ, MERC Alternative] [Staff notes that this calculation is not in the record of this proceeding, other than as MERC's recommended adjustment clarification to finding 251.]

7. For test year post-retirement medical plan expense and life insurance expense, adopt ALJ finding 256 and allow MERC to calculate:

    - Test year post-retirement life expense using the December 31, 2013 updated plan asset values and discount rate, and adjust its initially proposed expense accordingly; [MERC, ALJ] [If this alternative is selected, the Commission may wish to require MERC to provide the adjustment amount for post-retirement life expense, including its allocation of the IBS expense. The difference between its initially proposed post retirement life plan expense and its December 31, 2013 update may be only a small dollar amount.]
    - Test year post-retirement medical plan expense using the March 1, 2014 updated plan asset values and discount rates, and to reduce its initially proposed post retirement medical plan expense by $140,720. [MERC, ALJ, accepted by DOC]

8. Or instead, for consistency, if the Commission adopts ALJ finding 250 for pension expense, it may wish to require MERC to use a five-year historical average of discount rates to calculate test year post-retirement medical plan and/or post-retirement life insurance expense. [Note: Not recommended by any party. If this alternative is selected, the Commission may wish to modify ALJ proposed findings 250, 251 and 256 accordingly.]

9. Open a generic inquiry into how the discount rate should be derived and applied in calculating future pension expenses for setting rates in Minnesota.

10. Clarify ALJ finding 254 by replacing the words "rate base" with:

    - "expense" [MERC]; or

    - "base rates" [DOC].

11. Replace ALJ finding 251 with the following:

    Applying a five-year historical average of discount rates results in a reduction to pension expense of $668,392. [MERC] [Staff notes that this number has not been vetted on the record in this proceeding].

12. Correct finding 209 by replacing the words "expected return on plan assets" with "plan asset values as of December 31, 2013". [DOC]

(Note: These decision alternatives correspond to alternatives 36 through 47 on the deliberation outline.)

Reference to the Record
MERC Ex. 13, Cleary Direct at p. 14.
Evidentiary Hearing Transcript at pp. 23, 54-56, 59-61, 213-216.
MERC Ex. 26, Hans Direct at pp. 4, 8-13, 15-16.
MERC Ex. 27, Hans Rebuttal at pp. 4-17.
MERC Post Hearing Brief at pp. 52-63.
MERC Reply Brief at pp. 42-44.
DOC Ex. 217, St. Pierre Direct at pp. 7-11, 28-34.
DOC Ex. 219, St. Pierre Surrebuttal at pp. 2-4, 7-9, 25-33.
DOC Post Hearing Brief at pp. 115-123.
DOC Reply Brief at pp. 19-24.
ALJ Report at pp. 33-41.
MERC Clarifications and Exceptions to the ALJ Report at pp.16-17.
DOC Limited Exceptions to the ALJ Report at pp. 14-24, and 30-31.

Uncollectible Expense

PUC Staff: Sundra Bender

This issue is disputed between MERC, the Department, and the OAG.

MERC

MERC initially proposed to include $1,765,884 of uncollectible expense in the 2014 test year.[125] MERC witness Seth DeMerritt stated in his direct testimony that MERC calculated the 2014 uncollectible expense using the same methodology approved in MERC's last rate case.
To calculate its proposed $1,765,884 of uncollectible expense, MERC calculated a three-year (2012-2012) average of uncollectible expense over tariff revenues of 0.650401% and applied this percentage to MERC's 2014 test year forecasted tariff revenues at present rates plus an assumed rate increase of $14 million. Mr. DeMerritt explained that the $14 million assumed rate increase does not tie to the revenue deficiency amount proposed in this docket, because by changing the bad debt expense the revenue deficiency changes and a circular reference is created. Therefore, MERC proposed a number in close proximity to the revenue deficiency to get what it proposed to be a reasonable uncollectible expense forecast.[126]

In rebuttal testimony, Mr. DeMerritt disagreed with the Department's recommendation to use the 2013 uncollectible expense ratio to calculate test year bad debt expense. Mr. DeMerritt stated the three-year uncollectible expense ratio MERC proposed to use is consistent with the approach approved by the Commission in MERC's 2008 and 2010 rate cases. Mr. DeMerritt also stated that, based on past Commission precedent, as well as past support from the DOC and OAG, MERC believes the levelization approach is a more reasonable method than picking a fixed point in time. Mr. DeMerritt also proposed to update the uncollectible expense calculation with the revised test year revenues at current rates as calculated in MERC witness Gregory Walters' rebuttal Exhibit (GJW-1) and to include $12,000,000 for an assumed rate increase based on MERC's rebuttal position for the revenue requirement. (See Mr. DeMerrit's rebuttal testimony (SSD-3) for the calculation—which shows revised test year uncollectible expense of $2,016,410).[127]

MERC also disagreed with OAG witness John Lindell that test year bad debt expense should be $1,350,000. Mr. DeMerritt stated that it was well documented in MERC's last rate case that bad debt expense fluctuates from year to year, and that Mr. Lindell recognizes this fluctuation on page 6 of his direct testimony in this case. Therefore, MERC maintained that using an average ratio of Bad Debt Expense over Revenues is the correct approach for calculating Bad Debt expense.[128]

[125] MERC Ex. 19, DeMerritt Direct at 17.
[126] MERC Ex. 19, DeMerritt Direct at 16-17, SSD-4.
[127] MERC Ex. 24, DeMerritt Rebuttal at 9-10, SSD-3.
[128] MERC Ex. 24, DeMerritt Rebuttal at 20-21.

Department

In her direct testimony, Department witness Michelle St. Pierre compared the actual ratio (0.549760%) of the 2013 bad debt expense to 2013 tariffed revenues to the 2012 ratio (0.654342%) and MERC's proposed test year ratio (0.650401%) and concluded that the uncollectible expense rate appears to be going down rather than up as MERC forecasted for the test year. The Department concluded that MERC's proposed test-year uncollectible expense ratio is unreasonable and recommended the more current 2013 ratio of 0.549760% be used.[129]

Ms. St. Pierre stated that her calculation is similar to MERC's calculation since it adds the Department's recommended revenue deficiency rather than MERC's revenue deficiency proxy to the tariffed sales revenue at present rates. However, she agreed with MERC that the calculation of uncollectible expense is circular. As a result, the Department recommended for purposes of this rate case, that the revenue deficiency determined in the Department's Direct Testimony be used as a proxy for calculating test-year uncollectible expense. The Department stated that the Commission could require MERC to adjust the uncollectible expense to reflect material changes to that amount, if any, once the Commission decides the revenue deficiency in this case.[130]

The Department recommended that the Commission reduce test year Customer Accounts expense by $334,503 for the Uncollectible Expense (from MERC's proposed $1,765,884 to the Department's calculated test year bad debt expense of $1,431,381.[131] [See St. Pierre Direct at (MAS-25).]

In surrebuttal testimony, Ms. St. Pierre agreed that use of averages can be appropriate when costs vary significantly upward and downward, but concluded that use of an average would not be reasonable in this instance since there is a clear trend in costs. She provided the following table to show that MERC's uncollectible ratio has been dropping year after year by approximately 0.10% every year since MERC's last general rate case test year 2011.

	Approved	2011 Actual	2012 Actual	2013 Actual
Uncollectible Exp.	$2,031,888	$1,984,374	$1,313,501	$1,481,318
Tariffed Revenue		$255,269,107	$200,736,162	$26,9448,208
% of Tariffed Rev.		0.777366%	0.654342%	0.549760%

Ms. St. Pierre continued to conclude that MERC's proposed test-year uncollectible expense ratio of 0.650401% is unreasonable and that the more current 2013 ratio of 0.549760% should be used.

[129] DOC Ex. 217, St. Pierre Direct at 39.
[130] DOC Ex. 217, St. Pierre Direct at 39-40.
[131] The $1,431,381 is equal to $260,364,869 times 0.549760%. The $260,364,869 number appears to add the tariffed revenues at present rates proposed and calculated by MERC to the Department's revenue deficiency instead of adding the tariffed revenues at present rates reflected in the Department's own Operating Income Summary, which include a recommended sales forecast adjustment and imputed CIP revenue adjustment. Neither of these are included in MERC's calculation of tariffed revenues at present rates in its direct filing.

In its Reply Brief at pages 24-25, the Department corrected the Department's position with respect to uncollectible expense. The Department stated:

> In Surrebuttal, the Department's calculation incorrectly did not update the tariffed sales revenue. Based on review of MERC's Proposed Findings and further analysis, the Department now corrects its tariffed sales revenue to agree with MERC's tariffed sales revenue.
>
> The Department's corrected uncollectible expense is approximately $1,661,164 or a decrease of $104,720 from MERC's initial test year forecast of $1,765,884. This correction increases the Department's recommended revenue deficiency by $228,362 (due to cash working capital, interest synchronization and the bad debt adjustments) from $3,300,164 to $3,528,525.
> [Footnotes omitted.]

The Department included amended financials in its Reply Brief as Attachment 1.[132]

OAG

In his direct testimony, OAG witness John Lindell stated that MERC's projected bad debt expense is excessive based on a historical analysis of bad debt expense and revenues. Mr. Lindell recommended a test year bad debt expense of $1,350,000, which he said is higher than MERC's 2012 bad debt of $1,313,501 and would also take into consideration the much improved economy and the lower relative price of natural gas.[133]

In surrebuttal testimony, Mr. Lindell stated that the OAG does not support the levelization approach recommended by MERC despite having supported it in the past. Additionally, he stated that MERC contradicts is own support for a levelization approach by refusing to include the most recently completed year 2013 in its levelization calculations. According to Mr. Lindell, bad debt expense is very volatile from year to year due in part to accounting requirements and cannot be levelized like other types of expenses. An improved economy, lower gas prices and the accounting approach used to establish bad debt expense for financial reporting purposes support making an estimate that more closely reflects the bad debt expense experienced by MERC for 2013. The OAG continued to recommend its proposed bad debt expense of $1.35 million.

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[132] Staff notes that neither the Department's surrebuttal testimony, nor its Reply Brief match the tariffed revenues to the Department position presented in its financials. The Operating Income Summary statement provided in Ms. St. Pierre's surrebuttal testimony at (MAS-S-5), as well as the Operating Income Summary provided in the Department's Reply Brief, show the Department's position on Natural Gas Revenue (tariffed revenues at present rates) to be $311,356,621. This number is before adding the Department's recommended revenue deficiency. However, it appears the Department has double counted the increase in purchased gas expense and revenues associated with the forecast increase. The Department's financial statements reflect purchased gas expense and matching revenues of $221,858,262, whereas Ms. Otis's surrebuttal testimony indicates the Department's position is that purchased gas expense and revenue should be $214,858,858. Staff also notes that the Department's financial schedule position, although showing a smaller revenue deficiency, actually shows a higher test year revenue requirement and test year revenues than MERC's rebuttal position. This is mainly due to the adjustments the Department made to purchased gas costs.

[133] OAG Ex. 151, Lindell Direct at 7.

ALJ

ALJ proposed findings 283 through 296.

In proposed finding 296, the ALJ stated:

> 296. The Administrative Law Judge agrees with each of the parties, in part. In his view, the Commission should use the average percentage of tariffed revenue from the three most-recent years (2011, 2012 and 2013) and then apply this percentage to MERC's 2014 test year forecasted tariff revenues, plus an assumed rate increase of $12,000,000. This method relies upon the most-recent figures, accounts for variability in the rates of uncollectible expense and best carries forward the Commission's earlier approaches to these issues.

Exceptions

The Department and the OAG filed exceptions on this issue.

OAG

The OAG continued to recommend that the Commission adopt the OAG's recommended level of uncollectible expenses, and also addressed concerns about apparent inconsistencies within the ALJ's method for calculating uncollectible expenses. According to the OAG, the ALJ's recommendation that the percentage should be applied to MERC's forecasted tariffed revenues plus an assumed rate increase of $12,000,000 is at odds with the ALJ's final summary in this case, in which the ALJ indicates that "MERC's revenue deficiency is approximately $3,300,164."

The OAG stated that, "Based on the ALJ's conclusion that MERC is entitled to increase rates by only $3.3 million, it is unreasonable to assume a rate increase of $12 million for purposes of calculating uncollectible expenses." The OAG took exception to the ALJ's finding and recommended modifying finding 296 as follows:

> 669. [Staff believes this should be 296.] The Administrative Law Judge agrees with each of the parties, in part. In his view, the Commission should use the average percentage of tariffed revenue from the three most-recent years (2011, 2012 and 2013) and then apply this percentage to MERC's 2014 test year forecasted tariff revenues, plus an assumed rate increase of $ ~~12,000,000~~ 3,300,164. This method relies upon the most-recent figures, accounts for variability in the rates of uncollectible expense and best carries forward the Commission's earlier approaches to these issues.

Department

The Department stated that it continues to disagree with the Company's proposal and the ALJ's recommendation to use an average of three past years when calculating the uncollectable expense ratio in this instance for the following reasons:

- Averaging several years' revenues is not a reasonable methodology for calculating an expense in circumstances where there is a clear trend for costs to be varying in a single direction.

- Averaging several years' revenues can be appropriate when costs vary significantly up and down from year to year. Such is not the case here.

- It is not appropriate to use averaging when there is a trend of diminution in cost, especially when any doubt as to reasonableness must be resolved in favor of the consumer.

- There is no factual evidence to support a conclusion that uncollectible debts reasonably could be expected to be greater in the 2014 test year than in 2013, to justify use of an averaging methodology based on future cost increases.

The Department also disagreed with the ALJ's recommendation to apply the uncollectible expense ratio to MERC's 2014 test year forecasted tariff revenues, plus "an assumed rate increase" of $12,000,000. According to the Department, adding a $12,000,000 "assumed rate increase" to the test year forecasted tariff revenues, instead of adding the revenue deficiency that the Commission will determine, is inconsistent with other recommendations in the ALJ Report regarding the amount of the revenue deficiency.

The Department stated that it is possible that the inclusion of the $12,000,000 in paragraph 296 may have been a simple editing mistake or oversight. However, the Department stated, "Even if inclusion of the $12,000,000 in paragraph 296 was intentional, it should not be adopted by the Commission." According to the Department, the record does not support the inclusion of the $12,000,000 "assumed rate increase" instead of the revenue deficiency amount that will be determined by the Commission.

In conclusion, the Department continued to recommend that the Commission use MERC's actual 2013 uncollectible expense ratio of 0.549760%. The Department further stated that to determine the test-year amount in the compliance filing, MERC should multiply this actual 2013 uncollectible expense ratio (of 0.549760) by the Department's and MERC's agreed-upon test-year tariffed sales revenue and add the revenue deficiency amount as determined by the Commission.

The Department recommended adoption of the ALJ Report only after amending the following paragraphs as indicated below:

> 292. The Department recommended that MERC use the 2013 actual uncollectible expense ratio of 0.549760 percent rather than MERC's proposed

ratio of 0.650401 percent. The Department argues that the averaging of uncollectible expenses (and percentages) is not appropriate when there is "a clear downward trend" in the levels of uncollectible expense. MERC's uncollectible ratio has been dropping year after year by approximately 0.10 percent each year since MERC's last general rate case test year, 2011. Because doubt as to reasonableness must be resolved in favor of the consumer, Minn. Stat. § 216B.03 (2012), it is inappropriate to average when there is a trend of diminution in cost.

293. Specifically, the Department recommended that the 2013 percentage of tariffed revenue (0.549760%) be applied to corrected projections of tariffed revenue in the test year, for an uncollectible expense amount of ~~$1,657,805~~ $1,661,164.

294. Pointing to the wide fluctuation in the rates of bad debt from year to year, the OAG-AUD argues that the methods of averaging urged by MERC ~~and the Department~~ are not reliable. It maintains that the Commission should instead consider economic factors, such as "the much improved economy and the lower relative price of natural gas," when assigning an uncollectible expense amount of $1,350,000 for the test year.

296. The Administrative Law Judge concludes that MERC's proposed test-year uncollectible expense ratio of 0.650401 percent is unreasonable and that the more current 2013 ratio of 0.549760 percent should be used ~~agrees with each of the parties, in part. In his view, the Commission should use the average percentage of tariffed revenue from the three most-recent years (2011, 2012 and 2013) and then apply this percentage~~ and applied to the sum of MERC's 2014 test year ~~forecasted~~ tariffed sales revenues agreed-upon by MERC and the Department, plus ~~an assumed rate increase of $12,000,000~~ the revenue deficiency that the Commission approves in this rate case. This method relies upon the most-recent figures, accounts for ~~variability~~ the downward trend in the rates of uncollectible expense due to the much improved economy and the lower relative price of natural gas that the U.S is experiencing at present ~~and best carries forward the Commission's earlier approaches to these issues~~.

Staff Comment

There are potentially two issues to decide with respect to uncollectible expense. First, should it be calculated with a percentage of revenues calculation, or should a set dollar amount be determined. If a specific dollar amount of test year uncollectible expense is approved, then no further issue remains. However, if the Commission decides to approve a percentage of revenues calculation (regardless of whether it approves the percentage proposed by MERC, the one recommended by the Department, or the one recommended by the ALJ), then it should clarify which revenue level should be used: the one used by MERC in its rebuttal testimony ($310,025,617), the one used by the Department in its post hearing reply brief ($302,161,785),[134]

[134] Staff notes that the Department appears to have not included its recommended forecast margin and imputed revenue adjustments in its calculation of the revenue level. If these were included, it appears the revenue level (without further adjusting cash working capital and interest synchronization) would be approximately $307,885,740

the one which reflects the Commission's decisions in this case and the related base cost of gas docket, or some other level.

The Commission's decision on the appropriate base cost of gas to use is likely to have the largest impact on the revenue level since gas costs are such a large percentage of tariffed revenues. Staff notes that MERC and the Department's Operating Statement's reflect different tariffed revenues at present rates due to differing levels of purchased gas cost revenues and the imputation of CIP revenues. Ultimately, the Commission's decisions in this rate case and the related base cost of gas docket will determine the over-all revenue requirement and test year tariffed sales revenues. These decisions include more than its decisions on the revenue deficiency (such as its decision on the base cost of gas and imputation of CIP revenue). It is unclear to staff why the Department proposed to modify ALJ finding 296 to state "applied to the sum of MERC's 2014 test year tariffed sales revenues agreed-upon by MERC and the Department, plus the revenue deficiency that the Commission approves in this rate case" instead of recommending that it be applied to the 2014 test year tariffed sales revenue determined by the Commission's decisions in this rate case and the related base cost of gas docket. Moreover, it appears to staff that MERC and the Department have different positions on test year tariffed sales revenues and staff is unaware of any agreement between MERC and the Department as to what this number should be. Additionally, the Department's recommended modification reintroduces the circular reference.

If the Commission determines that a percentage of revenues method is appropriate and wants the applicable revenue level to reflect the Commission's decisions, for the purpose of calculating the recoverable uncollectible expense it may wish to require that the Commission determined revenue deficiency be rounded down to the nearest million, similar to the method MERC used, in order to eliminate the circular reference issue.

The ALJ's recommendation to use the average percentage of tariffed revenue from the three most-recent years (2011-2013) and then apply this percentage to MERC's 2014 forecasted tariff revenues, plus an assumed rate increase of $12,000,000, would result in a higher percentage (0.658787%) than MERC's proposed percentage of 0.650401%, and consequently a somewhat higher uncollectible expense than that proposed by MERC. In its compliance to the ALJ's Report, MERC calculated the uncollectible expense under the ALJ's recommendation to be $2,042,408 (by applying 0.658787% to $310,025,617 of test year tariffed revenues). In its letter commenting on MERC's compliance filing, the Department stated that the base cost of gas used in the calculation should be changed. The Department calculated the uncollectible expense under the ALJ's recommendation to be $2,059,362 (by applying 0.658787% to $312,599,125 of test year tariffed revenues). Staff notes that MERC's compliance filing financial statements reflect test year tariffed revenues of $307,190,775 (or $307,422,039[135] + ($231,264)[136]). The

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(or $302,161,785 + $1,965,865 + $3,758,090), compared to MERC's rebuttal revenue level of $310,025,617. In staff's view, the Department's recommendation to impute CIP revenues simply moves this level from the deficiency calculation to imputed tariff revenues at present rates, It does not remove them from tariff revenues. Staff notes that the Department's Operating Statement has the imputed revenues included in tariff revenues but the Department failed to add them into tariffed revenues in its uncollectible expense calculation. MERC's position would not add them into tariffed revenues at present rates since they are reflected in MERC's calculation of the revenue deficiency. But, either way staff believes they should be part of test year tariffed revenues.

[135] Operating Income Summary-Line 1-Natural Gas Revenue.

financial statements included in the Department's September 8, 2014 Supplemental Letter commenting on MERC's filing in compliance to the ALJ's Report reflect test year tariffed revenues of $309,784,163 (or $304,357,215 + $5,426,948). Staff notes that even though the revenue deficiency reflected in these schedules ($5,426,948) is significantly less than the approximately $12,000,000 assumed rate increase the ALJ recommended be added to MERC's tariffed revenues, the end result of test year revenues of approximately $309,784,163 is not that different than the number calculated by MERC ($310,025,617) when adding the assumed increase of 12,000,000. This similarity despite the difference in revenue deficiency is largely due to the imputation of CIP revenues and adjustment to the base cost of gas.

Decision Alternatives for Uncollectible Expense

1. Adopt the ALJ's proposed finding 296 and find that the average percentage (0.658787%) of tariffed revenue from the three most recent years (2011, 2012 and 2013) should be used and applied to:

   a) MERC's 2014 test year forecasted tariff revenues, plus an assumed rate increase of $12,000,000. [ALJ] [If this alternative is selected, it should be clarified whether this means MERC's 2014 test year forecasted tariff revenues at present rates ($298,025,617) as calculated in MERC's rebuttal testimony plus $12,000,000, for a total of $310,025,617, or something else]. OR

   b) Tariffed revenues as calculated in the Department's comments on MERC's compliance filing, plus an assumed rate increase of $12,000,000, for a total of $312,599,125. OR

   c) MERC's 2014 test year forecasted tariff revenues, plus an assumed rate increase of $3,300,164 per the OAG's proposed modification to the ALJ's finding 296 [Again, it should be clarified whether this means it should be added to tariffed revenues as calculated in MERC's rebuttal testimony ($298,025,617), or something else such as the tariffed revenues determined by the Commission's decisions in this rate case and the related base cost of gas docket.] OR

   d) The test year forecasted tariff revenues at present rates as determined by the Commission's decisions in this rate case and the related base cost of gas docket, Docket No. G011/MR-13-732, plus the approximate revenue deficiency determined by the Commission's decisions (i.e., rounded down to the closest million dollars to eliminate the circular reference). OR

2. Find that MERC's three-year (2010-2012) uncollectible expense ratio (0.650401%) and forecasted $2,016,410 of uncollectible expense for the 2014 test year is reasonable and should be adopted in this rate case.[137] [MERC] OR

[136] Revenue Requirements Summary-Line 7-Gross Revenue Deficiency.
[137] MERC Ex. 24, DeMerritt Rebuttal at (SSD-3)

3. Find that MERC's three-year (2010-2012) uncollectible expense ratio (0.650401%) is reasonable and should be applied to the test year forecasted tariff revenues determined by the Commission's decisions in this case and the related base cost of gas docket, including the Commission's decisions on the revenue deficiency. [To eliminate the circular reference, if the Commission selects this alternative it may wish to require for purposes of this calculation that the Commission determined revenue deficiency be rounded down to the nearest million.] OR

4. Adopt the OAG's position and require MERC to reduce test year uncollectible expense to $1.35 million. [OAG] OR

5. Find that the Department's recommended 2013 uncollectible expense ratio (.549760%) and forecasted $1,661,164 of uncollectible expense for the 2014 test year is reasonable and should be adopted in this rate case.[138] [DOC] OR

6. Adopt the Department's proposed modifications to the ALJ findings and require MERC to apply the 2013 ratio of 0.549760 percent to the sum of MERC's 2014 test year forecasted tariffed sales revenues agreed-upon by MERC and the Department, plus the revenue deficiency that the Commission approves in this rate case. [If the Commission chooses this alternative, it should request that the parties clarify what the agreed upon 2014 test year forecasted tariffed sales revenues are because the parties have different positions in this case and staff is unaware of any agreed upon number]. OR

7. Adopt the Department's position to use the 2013 ratio of 0.549760% and apply to test year forecasted tariff revenues at present rates as determined by the Commission's decisions in this rate case and the related base cost of gas docket, Docket No. G011/MR-13-732, plus the approximate revenue deficiency determined by the Commission's decisions (i.e., rounded down to the closest million to eliminate the circular reference).

(Note: These decision alternatives correspond to alternatives 48 through 54 on the deliberation outline.)

<u>Reference to the Record</u>
MERC Ex. 19, DeMerritt Direct at pp. 16-17, SSD-4.
MERC Ex. 24, DeMerritt Rebuttal at pp. 9-10, and 20-21.
MERC Post Hearing Brief at pp. 36-38.
OAG Ex. 151, Lindell Direct at pp. 5-7.
OAG Ex. 154, Lindell Surrebuttal at pp. 3-4.
OAG Post Hearing Brief at pp. 7-9.
DOC Ex. 217, St. Pierre Direct at pp. 37-40.
DOC Ex. 219, St. Pierre Surrebuttal at pp. 35-38, MAS-S-10.
DOC Post Hearing Brief at pp. 125-129.
DOC Reply Brief at pp. 24-25.
ALJ Report at pp. 46-48.
OAG Exceptions to the ALJ Report at pp. 24-25.

[138] Department Post Hearing Reply Brief at Attachment 1, Bad Debt Expense Adjustment schedule.

DOC Limited Exceptions to the ALJ Report at pp.24-29.

Financial Issues - Uncontested

Charitable Contributions

PUC Staff: Ann Schwieger

MERC and the Department are in agreement on the issue of charitable contributions. The ALJ found the agreement to be reasonable. The Company proposed $32,309 of charitable contributions be included in the test year.

MERC included $31,050, or 100 percent, of its 2012 charitable contributions in its test year income statement. The test year amount is based on actual charitable contributions of $31,050 inflated 1.708 for 2013 and 1.993 for 2014 is approximately $32,209.

The Department objected to the Company including 100% of charitable contributions in the test year because the Commission's policy (Minn. Stat. § 216B.16, subd. 9) states, in part:

> The Commission shall allow as operating expenses only those charitable contributions which the Commission deems prudent and which qualify under Minn. Stat. 290.21, subd. 3(b). Only 50 percent of the qualified contributions shall be allowed as operating expenses.

The Department recommended that the Commission reduce administrative and general expenses by $16,105 for the test year charitable contributions. The Company stated it agreed with the Departments recommendation.

Decision Alternative for Charitable Contributions

1. Reduce MERC's test year administrative and general expense by $16,105 for the test year charitable contributions. (MERC, Department, ALJ)

(Note: This decision alternative corresponds to alternative 55 on the deliberation outline.)

<u>Reference to Record</u>
MERC, Initial Filing, Volume 3, Document 15
DOC-DER, Exhibit 215, LaPlante Direct, March 4, 2014, Page 19
MERC, Exhibit 24, DeMerritt Rebuttal, April 15, 2014, Page 17
DOC-DER, Exhibit 216, LaPlante Surrebuttal, May 7, 2014, Page 5
DOC-DER, Initial Post Hearing Brief, June 24, 2014, Page 91
ALJ, Report, August 13, 2014, Page 48-49

Gate Station Remote Monitoring Project

PUC Staff: Ann Schwieger

This issue is resolved between MERC and the Department. The ALJ found that the Company's proposed recovery of the costs related to the gate stations project is reasonable and should be approved by the Commission. Constellation New Energy – Gas Division, LLC submitted testimony on this issue and requested that MERC complete the project by October 1, 2014. The gate stations project is a multi-year project and will not be completed in 2014.

The Company requested an increase of $330,000 to O&M expense to add remote monitoring to the distribution delivery points where MERC receives its natural gas supply. Remote monitoring will give MERC's engineers and gas controller's real time visibility of the performance of its system and increase reliability. The project began in January of 2014 and is expected to be completed in five years or until all of the equipment has been installed at the planned monitoring sites. MERC employees will oversee the contractors installing the equipment and will be involved with the capital side of the project as well. The costs of the gate station equipment and installation will be capitalized. The increase in O&M expense is requested to cover the incremental costs of operating and maintaining the equipment on an ongoing basis.

The Department concluded that the gate stations project would be ongoing over a period of five years and recommended that the Commission approve the associated costs as reasonable and included in the test year.

Decision Alternative for Gate Station Remote Monitoring Project

1. Increase MERC's test year operations and maintenance expense by $330,000 for costs associated with the gate station remote monitoring project. (MERC, Department, ALJ)

(Note: This decision alternative corresponds to alternative 56 on the deliberation outline.)

<u>Reference to Record</u>
MERC, Exhibit 19, DeMerritt Direct, September 30, 2013, Page 17
DOC-DER, Exhibit 217, St. Pierre Direct, March 4, 2014, Page 46
Constellation, Exhibit 125, Haubensak Direct, March 4, 2014, Page 4
DOC-DER, Exhibit 219, St Pierre Surrebuttal, May 7, 2014, Page 41
DOC-DER, Initial Post Hearing Brief, June 24, 2014, Page 132
ALJ, Report, August 13, 2014, Page 48-49

Sewer Lateral Legacy Pilot Program

PUC Staff: Ann Schwieger

This issue is resolved between MERC and the Department. The ALJ found that MERC's proposed recovery of the costs related to the sewer lateral legacy pilot program isreasonable and should be approved by the Commission. No other party offered testimony on this issue.

The Company requested an increase of $340,000 to Operations & Maintenance (O&M) expense to comply with requests from the Minnesota Office of Pipeline Safety to inspect legacy installations to insure that natural gas pipe is not intertwined with sewer line. If a conflict exists, it creates a risk to the public. If a sewer cleaning company attempts to clean a sewer line with a cutter, there is potential for a gas line to be cut resulting in a gas leak into the sewer system. An explosion could, and has occurred both within the natural gas distribution industry and within the state. The pilot program is to determine best practice, time to complete, and identify any risk and cost to achieve a complete assessment of MERC's system. The goal is to validate that MERC's system does not have any conflicts with sewer lines.

Based on its understanding that the Program was to begin in January 2014 and end in July 2014, the Department initially recommended the costs be levelized over a three year period. The Company clarified that the Sewer Laterals Legacy Program will be a multi-year program continuing until MERC's entire system has been inspected. The inspection work will be performed by contractors, with oversight provided by MERC employees. The majority of the $340,000 expense is attributed to contractor costs to perform the inspections and includes less than $1,000 for printed door tags and mailers to notify residents of the inspections. According to the Company, the costs are O&M costs rather than capital costs because they are for inspecting sewer lines not owned by MERC for conflicts with MERC owned gas lines.

Decision Alternative for Sewer Lateral Legacy Pilot Program

1. Increase MERC's test year operations and maintenance expense by $340,000 for costs associated with the sewer lateral legacy program. (MERC, Department, ALJ)

(Note: This decision alternative corresponds to alternative 57 on the deliberation outline.)

Reference to Record
MERC, Exhibit 19, DeMerritt Direct, September 30, 2013, Page 17
DOC-DER, Exhibit 217, St. Pierre Direct, March 4, 2014, Page 40
MERC, Exhibit 24, DeMerritt Rebuttal, April 15, 2014, Page 10
DOC-DER, Exhibit 219, St Pierre Surrebuttal, May 7, 2014, Page 38
Evidentiary Hearing Transcript, May 13, 2014, at 37-40, 44-45, 51-52
ALJ, Report, August 13, 2014, Page 48

Test Year Depreciation Expense

PUC Staff: Ann Schwieger

The Company and the Department have agreed on the parameters used to calculate the test year depreciation expense. No other parties submitted comments on the issue. The Company stated that it used the depreciation rates authorized in Docket No. G007,011/12-533 and forecasted expenditures and balances to project the 2014 test year depreciation expense. In a response to a Department informational request, the Company provided a spreadsheet showing the actual calculations.

Decision Alternative for Test Year Depreciation Expense

1. Upon filing of its next rate case, require the Company to provide a schedule showing the test year monthly depreciation expense calculations and show by FERC account the:

    - average monthly plant balance,
    - depreciation rates used,
    - monthly depreciation expense, and
    - totals.

(Note: This decision alternative corresponds to alternative 58 on the deliberation outline.)

<u>Reference to Record</u>
MERC, Exhibit 19, DeMerritt Direct, September 30, 2013, Page 11-12
DOC-DER, Information Request 104, Test-year Depreciation Expense

Customer Service (Line) Extensions

PUC Staff – Bob Brill

Statement of the Issue - Amount of Adjustment
Staff believes all issues have been resolved and are uncontested. MERC's test year rate base should be reduced by $35,803.18 before calculating final rates.

Background
The Commission has previously approved three general types of service extensions for MERC:

A. <u>Free Footage Allowance</u> – This type of extension is approved when the number of feet of mainline and service line extensions[139] are within the footage allowance built into base

[139] The "free" footage allowance is not cost-free; rather, there is an assumed amount of extension costs built into base rates for all customers.

rates. Any extension beyond the "free" footage allowance would require a Contribution in Aid of Construction (CIAC) by the customer in order to receive service.[140]

B. Economically Feasible – This type of extension requires that the extension is shown to be cost/load justified.[141]

C. New Area Surcharge (NAS) Tariff[142] – When an extension to an area that has not previously received gas services because it was found not to be economically feasible, the customers in the newly piped area can agree to pay this surcharge so that current customers do not unduly subsidize the extension to new customers.

MERC's currently effective tariff reflects all three types of service extensions. Generally speaking, MERC uses the "Free Footage Allowance" for the majority of its residential service extensions. The each residential customer receives a 75 foot allowance and is accessed $5 per foot if the extension goes past the footage allowance. MERC stated that most of the residential service extensions are within the 75 foot allowance. For larger service extension requests, MERC uses its Commission approved economic feasibility model to determine if CIAC is necessary if the projected revenues of the service extension do not support the project.

Docket No. G999/CI-90-563 Requirements

In its March 31, 1995, Order in Docket No. 90-563, the Commission requested that the Department investigate in every rate case the gas utility company's service additions to rate base due to new service extensions during a general rate case to make sure:

- that LDCs (local distribution companies) are applying their tariffs correctly and consistently;
- that the additions are appropriately cost and load justified; and
- that wasteful additions[143] to plant and facilities are not allowed into rate base.[144]

1. Has MERC correctly and consistently applied its service extension tariff?

MERC[145]

MERC stated that it conducted a study for this rate case of all service and main extensions from April 2010 through March 2013; 4,503 service extension and 273 main projects. The time period represented the entire period since its previous Docket No. 10-977 rate case.

MERC's review identified 79 service extensions[146] during the tested period that did not comply with MERC's tariff. The primary reasons the service extension calculations were incorrect were

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[140] Unless it is determined that the anticipated revenue from that customer is sufficient to cover the costs over time to prevent an undue burden on existing customers

[141] One example of such justification would be the economic feasibility model the Company specified in its tariff to determine whether an extension project is economically feasible.

[142] MERC filed for its first NAS in Docket No. 524; *see* In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Tariff Revision and a New Area Surcharge for the Ely Lake Project (June 20, 2014)

[143] Loosely defined as a customer not paying its required CIAC contribution or incorrect MERC calculations thus, putting additional burden on the existing customers

[144] *See generally* MERC Ex. 14, Kult Direct and Department Ex. 210, Zajicek Direct at pp. 6-7

[145] See MERC Ex. 14, Kult Direct at pp.8-11; DGK-1 & DGK-2 and MERC Ex. 19, DeMerritt Direct at p. 28

the result of CIAC and excess footage charges not being properly calculated, the errors totaled $12,859.52. The investigation revealed that in every occurrence, the mistake involved a residential customer who was not properly billed CIAC or winter construction charges.

MERC identified 5 main extension projects that did not have the full project CIAC collected, this error totaled $16,310.50. MERC stated that it could not have explain why the customers were not billed the correct CIAC.[147]

To address the uncollected amounts from service and main extensions; MERC proposed to reduce the rate base in the current rate case by $29,170.02[148], which represents the discovered errors during the period.

In the future, MERC plans to hold regular training sessions before each construction season to improve the understanding of its process, rules, and records retention requirements.

<u>Department</u>[149]

The Department conducted its own investigation of MERC's service and main extension project. In response to the Department's informational requests, MERC provided the Department a random sample of extension projects using the *randomizer.org* website. MERC provided a sample of 226 of the 4,503 or service extension[150] and a sample of 41 of the 273 main extension[151] projects.

The Department's review revealed 2 additional service extension errors where excess footage was not billed correctly; MERC later identified that these errors were caused by human error. The Department discovered error amount totaled $323.91. The Department extrapolated the $323.91 error amount into $6,633.16[152] to represent a total for the entire group. The Department did not detect any additional error in its review of the main extension documents. The Department's proposed rate base adjustment totaled $35,803.18[153].

The Department concluded that MERC was still recovering the majority of required CIAC from the customers who impose these costs on the system. Further, MERC should continue to improve its application of its tariff to ensure errors are minimized and corrected. MERC should also improve its record keeping so that it is able to ensure that any errors made are caught during the processing of service and main extension projects.

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[146] Approximately 1.75% of all service extensions during the tested period (79 instances divided by 4,503 service extension)

[147] MERC Ex. 14, Kult Direct at pp. 10-11 and MERC Ex. 4, Initial Petition Volume 3: Informational Requirements, Document 2, Schedule B-3, line 27

[148] 12,859.52 plus $16,310.50

[149] See Department Ex. 210, Zajicek Direct at pp. 18-25 and 30-31; Schedules MZ-1 – MZ-4 and Department Ex.211, Zajicek Surbbuttal at pp. 1-2

[150] 5% of the total service extension projects

[151] 15% of the total main extension projects

[152] The Department calculated this amount by taking the average dollar error over the sample it reviewed and multiplied it by the total number of service extension projects from April 2010 to March 2013 ($332.91/226 = $1.4731 times 4,503 = $6,633.16).

[153] MERC's discovered error $29,170.02 amount plus the Department's additional $6,633.16 adjustment

The Department concluded that MERC has not shown in every instance that it correctly and consistently applied its extension tariff since its 2010 rate case. The level of rate base reduction remained small reflecting MERCs improvement since their 2008 rate case, but increased slightly over the Company's 2010 rate case. MERC has shown that policies put in place following the 2008 rate case have continued to result in improved application of its tariff, but there is further progress that can be made.

2. Were service and main extension appropriately cost and load justified?

MERC[154]

MERC stated that all new main projects are evaluated against standard investment guidelines that are calculated in its feasibility model. Further, the model has been approved by the Commission as an acceptable evaluation method that protects both existing and new customers from undue cost. MERC commented that the load information is reviewed for all new commercial accounts individually, and the residential accounts are based on average volumes across the entire customer base. MERC asserted that its extension tariff is appropriately cost and load justified.

Department[155]

The Department concluded that MERC's statements were reasonable.

3. Were the service and main extension plant additions wasteful and should not be allowed in rate base?

MERC[156]

MERC stated that it evaluated all new projects using its Commission approved tariff, and that it discovered wasteful additions as discussed above. MERC identified service and main extension errors since the 2010 rate case, and proposed a $29,170.02 rate base disallowance.

Department[157]

The Department concluded that MERC has not in every instance reflected practices that would prevent wasteful additions to plant and facilities. The Department agreed with MERC's $29,170.02 rate base disallowance proposal. In addition, based on its sample review of MERC's service and main extension records, the Department proposed an additional rate base disallowance of $6,633.16 for a total $35,803.18[158] rate base disallowance.

MERC Rebuttal

MERC agreed to the $35,803.18 rate base reduction.[159]

[154] See MERC Ex. 14, Kult Direct at pp.11-12
[155] See Department Ex. 210, Zajicek Direct at pp. 25-26
[156] See MERC Ex. 14, Kult Direct at p.12
[157] See Department Ex. 210, Zajicek Direct at pp. 26-27
[158] Department Ex. 210, Zajicek Direct at pp. 25, 27, 31 and Department Ex. 211Zajicek Surrbuttal at p. 3
[159] MERC Ex. 15, Kult Rebuttal at p. 3

Other Docket No. 90-563 Requirements

Pursuant to the Commission's March 31, 1995 Order,[160] MERC was required[161] to provide discussion on certain questions in this rate case, see the following discussion:

- Should the "free" footage or service extension allowance include the majority of all new extensions with only the extremely long extensions requiring a customer contribution-in-aid-of construction (CIAC)?

MERC

As its general policy, MERC believed that its "new" customers should receive some amount of line extension allowance at no cost to the new customer. MERC's current tariff allows the majority of new customers to receive service without a CIAC. For most residential services added in an existing service area,[162] its tariff provided the customer with 75 feet of service line allowance without requiring CIAC. MERC stated that this policy provides multiple benefits to new and old customers.

Department[163]

The Department concluded that MERC's extension policy on the footage allowance is reasonable and consistent with the Department's principles on footage allowances, as discussed above.

- How should the LDC determine the economic feasibility of service extension projects and whether the excess footage charges are collected?

MERC

MERC stated that it applied its economic feasibility model to all new customers applying for gas service where a current main does not exist. Further, its feasibility model provided for service connection without a CIAC where the economic support (customer revenues) exceeded the LDC's costs to serve the customer within a reasonable period of time. The feasibility model generally does not apply to individual, residential stand-alone service lines off existing mains.

The Commission has previously approved MERC's feasibility model used to test new extension projects. MERC commented that its extension tariff provides a reasonable balance between connection without a CIAC charge and recovery of excessive costs.

Department[164]

The Department concluded that MERC's tariff provisions were reasonable, and stated that MERC's overall approach to the economic feasibility of extensions and the collection of excess footage charges was reasonable since the approach balanced the connection to MERC's

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[160] ORDER TERMINATING INVESTIGATION AND CLOSING DOCKET, In the Matter of an Inquiry into Competition Between Gas Utilities in Minnesota, Docket No. G-999/CI-90-563
[161] See generally, MERC Ex. 14, Kult Direct at. pp. 3-7
[162] Where no main extension is required and no feasibility analysis has been previously prepared for the proposed service line
[163] See generally, Department Ex. 210, Zajicek Direct at pp. 8-10
[164] See generally, Department Ex. 210, Zajicek Direct at pp. 10-13

distribution system and recovery of the costs associated with longer, more expensive extensions from the new customer.

- Should the LDC's service extension policy be tariffed in number of feet without consideration to varying construction costs among projects or should the allowance be tariffed as a total dollar amount per customer?

MERC

MERC stated that due to the varying construction costs across its service area caused by factors such as geographic area, type of soil, size of lot, and amount of gas used, it would be difficult to develop a dollar-based, one-size-fits-all policy that is equitable to all customers. The designated footage allowance fits most customers and is relatively easy to apply and monitor. Moreover, in its 2008 rate case, the Commission approved tariff provisions authorizing MERC to charge customers for the cost of abnormal construction in certain circumstances where abnormal conditions exist.

Department[165]

The Department concluded that MERC's statements with respect to a footage allowance for residential customers are consistent and reasonable with its position on footage allowances.

- Is the LDC's extension charge refund policy appropriate?

MERC

MERC stated that it does not offer a refundable contract. MERC completes an economic feasibility analysis for a project and bases its estimate of revenues on the projected customer connection over time. MERC asserted that this policy is appropriate because the responsibility for ensuring that any non-feasible extension is refunded through a CIAC is shared between the developer and MERC.

Department[166]

The Department concluded that MERC's current no-refund policy appears to encourage reasonable upfront cost estimates with any CIAC being specified prior to the installation of the facilities. The Department did not propose at this time to require MERC to institute an extension refund policy.

- Should customers be allowed to run their own service line from the street to the house (or use an independent contractor) if it would be less expensive than having the utility construct the line?

MERC

MERC stated that to maintain the integrity of the distribution system and maintain compliance with the industry-required "Operator Qualifications," it cannot allow others preform this type of work. MERC commented that the "Distribution Integrity Management" regulations placed into

[165] See generally, Department Ex. 210, Zajicek Direct at pp. 13-15
[166] See generally, Department Ex. 210, Zajicek Direct at pp. 15-16

code in 2009 by the U.S. Department of Transportation – Pipeline and Hazardous Materials Safety Administration (PHMSA) make it necessary for it to have knowledge of the materials and quality of the systems it operates. MERC stated that PHMSA also requires it to implement integrity management programs to enhance safety by identifying and reducing pipeline integrity risks. MERC does not permit its customers to perform construction work in lieu of MERC's contractor.

Department[167]

The Department concluded that MERC's construction polices and tariff requirements are reasonable.

- Should the LDC be required to offer its customers financing for service extension charges? This could be offered as an alternative to paying extension charges in advance of construction.

MERC

MERC stated that it currently does not offer a financing option for service extensions.

Department[168]

The Department concluded that MERC's polices are reasonable, and that it is the responsibility of each utility to identify whether or not financing options are necessary for its particular customer types and what are the most appropriate financing options to offer.

ALJ

In proposed finding 527, ALJ Lipman found that MERC's Service and Main Extension reduction, allowance, and feasibility model are reasonable and recommended approval by the Commission.[169]

PUC Staff Comment

The Department concluded that MERC has reasonably responded to the questions and concerns in the Commission's 90-563 Order. However, the Department concluded that MERC has not shown in every instance that it correctly and consistently applied its service and main extension tariff since its 2010 rate case. MERC has responded to the Department's concerns with how it will address the service and main extension program going forward by providing additional training to its employees to help insure more accuracy in the future.

PUC staff agrees with the Department's and ALJ Lipman's recommendation that rate base should be reduced by the $35,803.18. PUC Staff further recommends to the Commission that it restates in its Order in this docket that the Commission's March 31, 1995 Order requirements[170] are applicable to subsequent rate cases. MERC continue to address the Commission's three concerns regarding MERC's service extension program and address the six questions listed above.

[167] See Department Ex. 210, Zajicek Direct at pp. 16-17
[168] See Department Ex. 210, Zajicek Direct at pp. 17-18
[169] See ALJ Report at pp. 77-79
[170] Docket No. 90-563

PUC staff also believes that MERC has adequately addressed its errors in applying its service and main extension tariff in the future by providing additional employee training.

Decision Alternatives

1. Adopt the recommendation of the Administrative Law Judge and reduce this docket's rate base by $35,803.18. (MERC, Department, ALJ)

or

2. Adopt the recommendation of the Administrative Law Judge and reduce this docket's rate base by $35,803.18 and restate the Commission March 31, 1995 Order requirements

- continue to address the three Commission concerns referred to in its March 31, 1995 Order requirements, and

- continue to address the six Commission questions listed in its March 31, 1995 Order requirements

(Note: These two decision alternatives correspond to alternatives 59 and 60 on the deliberation outline.)

Reference to Record
MERC Ex. 14 Kult, Direct, at pp. 3-12, and Schedules DGK-1 and DGK-2
MERC Ex. 19, DeMerritt Direct at p. 28
MERC Ex. 15, Kult Rebuttal at p. 4
MERC Ex. 4, Initial Petition Volume 3, Informational Requirements Document 2, Schedule B-3, line 27
Department Ex. 210, Zajicek Direct at pp. 6-18, 18-25, 25-27, 30-31, and schedules MZ-1-MZ-4
Department Ex. 211, Zajicek Surrbuttal at pp. 1-3

New Area Surcharge

PUC Staff: Bob Brill

Introduction

MERC's New Area Surcharge (NAS) tariff reflects a provision that states under no circumstance shall the surcharge applicable to any project remain in effect for a term to exceed 15 years. Because of the recent Minnesota propane crisis during the 2013-2014 heating season, the Department suggested that to make new natural gas projects more feasible in new areas, it might be reasonable for MERC's NAS tariff to be revised to allow a NAS surcharge for a period longer than 15 years.

Department

The Department recommended to the Commission that it open a separate proceeding to address this question. This would allow MERC to make a specific proposal and to allow all parties adequate time to analyze and comment on the proposal.[171]

MERC Rebuttal

MERC agreed with the Department's recommendation. MERC further agreed with the Department's recommendation to establish a separate docket outside this rate case to address a proposal to modify its current 15 year term. MERC stated that it planned to prepare and submit a revised NAS tariff petition later this year. On June 20, 2014, MERC filed its initial NAS filing requesting a tariff revision changing its new area surcharge term from 15 years to 30 years; a new area surcharge for the Ely Lake Project.[172]

ALJ

In proposed finding 511, ALJ Lipman found that the examination of MERC's NAS in a separate proceeding was appropriate.[173]

PUC Staff Comment

PUC staff agrees with the recommendations of the Department and believes a separate proceeding to decide this issue is appropriate. The NAS term issue has already been addressed in MERC's Docket No. 14-524, the Ely Lake project. In the 14-524 docket, MERC requested to change its NAS 15-year term to 30-year to give it more flexibility to attract more potential customers for project. For the Ely Lake project, MERC is requesting a NAS term of 20 years. (The Commission approved MERC's request for the Ely Lake project at its August 28, 2014 agenda meeting.)

Decision Alternatives

1. Adopt the Administrative Law Judge recommendation and let the NAS term be addressed in a separate docket; Docket No. 14-524. (MERC, Department, ALJ)

(Note: This decision alternative corresponds to alternative 61 on the deliberation outline.)

<u>Reference to Record</u>
Department, Ex. 210, Zajicek Direct at p. 12
Department, Ex. 211, Zajicek Surrebuttal at p. 5
MERC, Ex. 42, Walters Rebuttal at p. 13
Docket No. 14-524 filed June 20, 2014, In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Tariff Revision and a New Area Surcharge for the Ely Lake Project

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[171] Department Ex. 210, Zajicek Direct at p. 11-13 and Department Ex. 211, Zajicek Surrebuttal at p. 5
[172] MERC Ex. 42, Walters Rebuttal at p. 13; *see* In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Tariff Revision and a New Area Surcharge for the Ely Lake Project (June 20, 2014) (Docket No. 14-524).
[173] See ALJ Report at p. 76

Winter Construction Charges

PUC Staff: Bob Brill

Background

In its January 15, 2008 Order[174], the Commission required

> MERC must show, in the Companies' next general rate case, that no Winter Construction Charges were assessed to customers outside the tariffed Winter Construction Charges period (i.e., November 1 through April 1), and that no Winter Construction Charges incurred by the Companies from NPL, or any other winter construction contractor, outside the tariffed Winter Construction Charges period are proposed to be recovered from other ratepayers.

In its September 14, 2009 ORDER AFTER RECONSIDERATION,[175] the Commission required MERC to

> File testimony on whether winter construction charges were assessed to customers outside the winter construction charges period.[176]

MERC Direct

MERC stated that its review did not discover any invoices reflecting winter construction charges outside of the Winter Construction period from its contractor[177] from April 1, 2010 through March 31, 2013. As a result, MERC removed $0 for winter charges for work done outside the tariffed Winter Construction Charges period.[178]

Department Direct and Surrbuttal

The Department concluded that MERC complied with the Commission's 07-1188 and 08-835 Order requirements and concluded MERC's statement to be reasonable.

The Department agreed with MERC's assessment and proposed no further disallowances on winter construction.[179] The Department recommended that the Commission continue to require MERC to report in subsequent rate case petitions its study reflecting that no winter construction charges were assessed outside the Winter Construction Period.[180]

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[174] In the Matter of a Requests by Minnesota Energy Resources Corporation (MERC-PNG and MERC-NMU) (Collectively Referred to as MERC or the Companies) for Approval of the Companies' Proposed Winter Construction Charges Addendum (Addendum) and the Companies' Proposed Supplement to Winter Construction Charge Addendum (Supplement), Docket No. G-007,011/M-07-1188

[175] In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota, Docket No. G-007, 01l/GR-08-835

[176] MERC Ex. 14, Kult Direct at p. 13 and Schedule DGK-3

[177] Northern Pipeline Construction Company

[178] MERC Ex. 14, Kult Direct at p. 13 and MERC Ex. 19, DeMerritt Direct at p. 29

[179] Department Ex. 211, Zajicek Surrebuttal at 4.

[180] Department Ex. 210, Zajicek Direct at pp. 27-28 and Department Ex. 211, Zajicek Surrebuttal at p. 4

MERC Rebuttal

MERC agreed with the Department's recommendations.[181]

ALJ

In proposed finding 533, ALJ Lipman recommended that the Commission should accept MERC's proposed rate base disallowance as to winter construction charges; and that MERC make a like set of assessments and reports in its next general rate case.[182]

PUC Staff Comment

Staff believes that MERC's petition has complied when the 07-1188 and 08-835 Order requirements for winter construction charges. Staff agrees with the Department's and ALJ Lipman's recommendations. Staff further believes that the winter construction charges issue has been resolved and is uncontested.

Decision Alternative

1. Adopt the recommendation of the Administrative Law Judge and

- accept the Department recommendation that MERC complied with the requirements of the Commission 07-1188 Order, <u>and</u>

- continue the 07-1188 and 08-835 Order requirements in MERC's next rate case for reporting winter construction charges. (MERC, Department, ALJ)

(Note: This decision alternative corresponds to alternative 62 on the deliberation outline.)

<u>Reference to Record</u>
MERC Ex. 14, Kult Direct at p. 13 and Schedule DGK-3
MERC Ex. 15, Kult Rebuttal at p. 5
MERC Ex. 19, DeMerritt Direct at p. 29
Department Ex. 210, Zajicek Direct p. 28 and 31
Department Ex. 211, Zajicek Surrebuttal at p. 4

[181] MERC Ex. 15, Kult Rebuttal at p. 5
[182] See ALJ Report at p. 79

Farm Tap Safety Inspection Program

PUC Staff: Bob Brill

Background

In its February 17, 1998 Order,[183] the Commission required MERC to file in each subsequent general rate case petition a five-year report on the cumulative results of its Farm Tap Safety Inspection Program, and any future improvement recommendations. MERC was also required to continue to send farm-tap safety and information brochures to new farm tap customers before they take service and to all existing farm customers annually and to file reports on its farm tap inspection program on or before April 1 of each year.

MERC Direct

MERC stated that it complied with the Commission Order by inspecting all system farm taps[184] at least once during the 5-year period from 2008 through 2012. MERC stated that the inspections uncovered a total of 153 class leaks, see the following summary:

Class Type[185]	Number of Discovered Gas Leaks
Class 1	4
Class 2	15
Class 3	134

MERC stated that it was not making any recommendation for changing its Farm Tap Safety Inspection Program.

The South Dakota Farm tap customers were sold in May 2011, and are no longer customers of MERC. Therefore, these customers are no longer included in MERC's corporate structure and are not included in this filing.[186]

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[183] ORDER PERMITTING COMPANY TO CONTINUE DEFERRED ACCOUNTING, In the Matter of Peoples Natural Gas Company's Request to Establish a Tariff for Repairing and Replacing Farm Tap Lines, Docket No. G-011/M-91-989

[184] MERC stated that it had 1,907 farm taps on its system and performed 2,115 inspections during the stated five year period.

[185] MERC defines its leak classes as follows: Class 1 leaks are those that represent an existing or probable hazard to persons or property and require immediate repair or continuous action until the conditions are no longer hazardous. When a Class 1 leak is discovered, gas service to a farm tap fuel line is shut off until adequate repair or replacement is made. Class 2 leaks are non-hazardous at the time of detection but are repaired based on probable future hazard. When a Class 2 leak is discovered, it is repaired within six months of detection, and any such leak discovered after June 30 of any calendar year must be repaired no later than December 31 of the same year, or ground freezing, whichever comes first. Class 3 leaks are those that are non-hazardous at the time of detection and can reasonably be expected to remain non-hazardous. Class 3 leaks are reevaluated during the next scheduled survey or within 15 months of the date reported, whichever comes first, until the leak is re-graded or repaired.

[186] MERC Ex. 19, DeMerritt Direct at p. 29

Department Direct

The Department agreed with MERC's analysis and recommended the Commission require MERC to continue its Farm Tap Safety Program and to continue to submit in subsequent rate case petitions its 5 years farm tap inspection reports as required in the Commission's Orders.[187]

MERC Rebuttal

MERC agreed with the Department's recommendation.

ALJ

ALJ Lipman did not address the Farm Tap Safety Inspection Program in his report.

PUC Staff Comment

Staff agrees with the parties' assessment of the Farm Tap Safety Inspection Program and the recommendation that this program continue. For the sake of clarity, staff also recommends the Commission restate in its Order in this docket that the customer notice and reporting requirements that were established for MERC-PNG in 91-989[188] are still in effect. This will make it clear that ongoing compliance and reporting requirements have not changed. Those requirements are

- MERC shall continue to send farm-tap safety and information brochures to new farm tap customers before they take service and to all existing farm customers annually.
- MERC shall continue to file annual reports on its farm tap inspection program on or before April 1 of each year.
- Within 90 days of the end of each five-year inspection cycle and in each general rate case, MERC shall file with the Commission, the Department, and the Office of Pipeline Safety a five-year report including cumulative results of the inspection program and any recommendations for future improvements.[189]

Decision Alternatives

1. Adopt the Department recommendations and approve the continuation of the farm tap inspection program and require that MERC shall continue to submit information about the program in its next rate case. (MERC, Department)

<u>or</u>

[187] See Docket No. 91-989
[188] Dated February 17, 1998
[189] ORDER PERMITTING COMPANY TO CONTINUE DEFERRED ACCOUNTING, In the Matter of Peoples Natural Gas Company's Request to Establish a Tariff for Repairing and Replacing Farm Tap Lines, Docket No. G-011/M-91-989 (February 17, 1998)

2. Adopt the Department recommendations and approve the continuation of the farm tap inspection program and clarify that MERC

- shall continue to send farm-tap safety and information brochures to new farm tap customers before they take service and to all existing farm customers annually.

- shall continue to file annual reports on its farm tap inspection program on or before April 1 of each year.

- Within 90 days of the end of each five-year inspection cycle and in each general rate case, shall file with the Commission, the Department, and the Minnesota Office of Pipeline Safety a five-year report including cumulative results of the inspection program and any recommendations for future improvements.

(Note: These two decision alternatives correspond to alternatives 63 and 64 on the deliberation outline.)

Reference to Record
MERC, Ex. 14, Kult Direct at pp.14-15
MERC, Ex. 15, Kult Rebuttal at p. 6
Department, Ex. 210, Zajicek Direct at pp. 28-30
Department, Ex. 211, Zajicek Rebuttal at p. 4

Cost Allocations

PUC Staff: Sundra Bender

Jurisdictional Allocations Minnesota/Michigan
In his direct testimony, MERC witness Seth DeMerritt stated that MERC described the methodologies used to allocate costs between MERC-Minnesota and MERC-Michigan in Information Requirement Documents 4 (rate base) and 7 (O&M expenses), both contained in Volume 3 of MERC's filing. The first step is to functionalize the costs and rate base items as production, transmission, distribution, or customer. After the functionalization is completed, these costs are then allocated to MERC-Minnesota and MERC-Michigan using system sales as the allocator for energy and demand, total sales for transmission, distribution plant is used as the allocator for distribution costs and fixed charge count is used as the allocator for the customer function.

No party addressed or challenged MERC's cost allocations between Minnesota and Michigan.

Regulated/Non-regulated Service Choice Allocations
MERC's non-regulated operations are called Service Choice. Service Choice offers appliance repair, service protection plans, and heating, air conditioner and water heater repair and maintenance services. MERC's field technicians perform both regulated and non-regulated work

in the majority of the State. However, in Rochester and the Southern Metro area, MERC has dedicated employees for the utility and non-utility businesses.[190]

MERC uses three different methods of allocating the costs to the utility and non-regulated businesses: direct charge, allocation based on known factors, and general allocation. The majority of the costs (76.5%) are directly charged, 11.5% are charged based on known factors, and 12.0% are allocated based on the general allocator.[191]

The Massachusetts Formula, which is based on margin, net plant and payroll, is used to calculate the general allocation factor.[192] This general allocation factor does not follow the Commission's preferred methodology which requires that: "When neither direct nor indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator computed by using the ratio of all expenses directly assigned or attributed to regulated and nonregulated activities."[193] To demonstrate the reasonableness of its general allocation factor, MERC calculated the general allocation factor using 2012 data and the Commission's method and compared it to MERC's general allocation factor. According to MERC, the Commission's preferred method would have allocated 91.1% of the general common costs to the regulated utility, whereas MERC's method allocated only 87.7% of the general costs to the regulated utility.[194]

The Department recommended that the Commission accept the result of MERC's cost allocations to ServiceChoice in this rate case.[195]

<u>IBS Cost Allocations</u>

Integrys owns Integrys Business Support LLC (IBS). IBS provides shared or common services to Integrys and its subsidiaries, including MERC.[196]

According to MERC witness Tracy Kupsh, MERC's revenue requirement includes actual amounts charged from IBS to MERC in 2012, inflated to 2014, and adjusted for known and measurable changes for the services that IBS provides to MERC. Ms. Kupsh stated:

> These amounts include costs that are directly assigned to MERC as well as costs that are assigned to MERC using cost-causal allocators, with the exception of the General/Corporate Allocator. MERC does not seek to recover the difference in cost calculated using the General/Corporate Allocation method in the Regulated AIA and the Commission's preferred general allocation method. The two methods produced similar results with a difference between the two methods of $3,314 in 2012. MERC is seeking to recover the smaller amount provided by the Commission's preferred allocation method in this rate case.

[190] MERC Ex. 40, Walters Direct at 34.
[191] MERC Ex. 40, Walters Direct at 35.
[192] Ibid, at 36.
[193] MERC Ex. 40, Walters Direct at 37.
[194] MERC Ex. 40, Walters Direct at 37-38.
[195] DOC Ex. 215, La Plante Direct at 12.
[196] DOC Ex. 215, La Plante Direct at 4.

The regulated affiliated interest agreement (AIA) governing the provision and allocation of shared services between IBS and it public utility subsidiaries was previously reviewed by the Department in Docket No. G007,011/AI-07-779, where it was originally approved, and subsequently in Docket Nos. G007,011/AI-08-1376, G007,011/AI-09-1244, G007,011/AI-11-168, G007,011/AI-12-910, and G011/AI-13-934, where it was modified.[197]

Department witness Lerma La Plante states at page 8 of her direct testimony that, because IBS's General/Corporate Allocation method is not the same as the Commission's preferred general allocation method, in its March 5, 2008 Order in Docket G007,011/AI-07-779, the Commission required that:

> MERC shall demonstrate in the Company's future general rate cases that the General/Corporate Allocation method provides similar results compared to the Commission's preferred general allocation method, or that the Company's method better serves the public interest.

The Department concluded that MERC's approach in this rate case, seeking recovery of the smaller amount of allocations provided by the Commission's preferred general allocation method, is reasonable.

ALJ

ALJ proposed findings 333 through 335; 399 through 416.

In proposed findings 399 through 409, the ALJ addressed MERC's IBS cost allocation adjustment, and at proposed findings 407 through 409 he stated:

> 407. MERC provided calculations showing that the Commission's preferred method resulted in a lower allocation factor; but that the two methods produced very similar results. Applications of the two methods resulted in a difference of $3,314 for 2012.
>
> 408. MERC proposed to recover the smaller amount, as would have resulted from the Commission's preferred allocation method.
>
> 409. The Administrative Law Judge finds that MERC's IBS Cost Allocation adjustment is consistent with the Commission's preferred general allocation method and should be approved in this rate case.

In proposed findings 410 through 416, the ALJ addressed MERC's cost allocations to ServiceChoice and at proposed findings 415 through 416 he stated:

> 415. The Department reviewed MERC's cost allocations and concluded that use of MERC's methodology did not result in significant differences from the

[197] DOC Ex. 215, La Plante Direct at 7.

Commission's preferred methods. It recommends that the Commission accept the results of MERC's cost allocations to ServiceChoice in this rate case.

416. The Administrative Law Judge finds that MERC's Cost Allocations to ServiceChoice are reasonable and should be accepted in this rate case.

Decision Alternatives

1. Adopt the ALJ's finding that MERC's IBS Cost Allocation adjustment is consistent with the Commission's preferred general allocation method and should be approved in this rate case. [MERC, DOC, ALJ]

2. Adopt the ALJ's finding that MERC's cost allocations to ServiceChoice are reasonable and should be accepted in this rate case. [MERC, DOC, ALJ]

(Note: These decision alternatives correspond to alternatives 65 and 66 on page 11 of the deliberation outline.)

Reference to Record
MERC Ex. 19, DeMerritt Direct at pp. 22, 29-30, SSD-12.
MERC Ex. 12, Kupsh Direct at pp. 2-3, 10-21.
MERC Ex. 40, Walters Direct at pp. 34-38, and (GJW-2).
DOC Ex. 215, La Plante Direct at pp. 3-9.
ALJ Report at pp. 53, 61-64.

Interest Synchronization

PUC Staff: Sundra Bender

In its filing, MERC included test year taxes related to interest synchronization of $98,779. In rebuttal testimony, MERC witness Seth DeMerritt stated that MERC agrees with the Department that an interest synchronization adjustment is needed and MERC will make an interest synchronization adjustment based on any adjustments to rate base or interest. However, Mr. DeMerritt stated, the actual level of the interest synchronization adjustment is dependent on the final outcome of the decisions that are made related to the rate base and interest adjustments.[198] Mr. DeMerritt included an updated calculation of MERC's interest synchronization position in which it revised the tax effect of interest synchronization downward. Based on the Company's rebuttal position, the tax effect of interest synchronization was adjusted downward from $98,779 to $85,382.[199]

As explained in the direct testimony of Department witness Michelle St. Pierre, interest synchronization is used for ratemaking to determine the amount of interest expense to be used in the calculation of income tax. When an adjustment is made to MERC's weighted cost of debt,

[198] MERC Ex. 24, DeMerritt Rebuttal at 11.
[199] MERC Ex. 24, DeMerritt Rebuttal at (SSD-4) Page 6.

test-year rate base or operating income statement, it is also necessary to make an interest synchronization adjustment.[200] Based on initial Department recommended adjustments, Ms. St. Pierre calculated that her interest-synchronization adjustment increases MERC's test-year tax expense by $190,650 for total test year taxes related to interest synchronization of $289,429. [201]

In surrebuttal, Ms. St. Pierre stated that she and MERC agree with the methodology for calculating interest synchronization.[202]

ALJ

ALJ proposed findings 461 through 466.

In proposed finding 466, the ALJ found that "MERC's Interest Synchronization methods set forth in the Department's Direct Testimony are reasonable and any recalculated adjustments are to be modeled in MERC's final compliance filing."

Decision alternatives for Interest Synchronization

1. Adopt the agreed upon interest synchronization methodology and order that the final adjustment be based on final Commission-approved figures. [MERC, DOC, ALJ]

(Note: This decision alternative corresponds to alternative 67 on page 11 of the deliberation outline.)

<u>Reference to Record</u>
MERC Ex. 4, Initial Filing Volume 3, Document 5, Schedule C-1.
MERC Ex. 24, DeMerritt Rebuttal at pp. 11, SSD-4, page 6.
DOC Ex. 217, St. Pierre Direct at pp. 49.
DOC Ex. 218, St. Pierre Direct Attachments at (MAS-7).
DOC Ex. 219, St. Pierre Surrebuttal at pp. 42-43, (MAS-S-7).
ALJ Report at pp. 70-71.

Cash Working Capital

PUC Staff: Sundra Bender

MERC performed a lead/lag study to determine the cash working capital component of working capital. In his direct testimony, MERC witness Seth DeMerritt stated that a lead/lag study measures the differences in time frames between (1) the time that service is rendered until the revenues for that service are received (lead) and (2) the time that labor, materials, or services are used in providing service until expenditures for such items are made (lag). Each major category of expense and its applicable lag days are compared to the calculated revenue lead days. The

[200] DOC Ex. 217, St. Pierre Direct at 49.
[201] Ibid and DOC Ex. 218, St. Pierre Direct Attachments at (MAS-7)
[202] DOC Ex. 219, St. Pierre Surrebuttal at 43.

difference between these periods, expressed in terms of days, times the average daily operating expenses, produces the cash working capital required, or available, for those operating expenses. In his direct testimony, Mr. DeMerritt calculated a negative test year cash working capital amount of $3,916,174 (Minnesota portion is a negative $3,908,368). Mr. DeMerritt stated that negative cash working capital indicates that revenues are being collected prior to the date when the associated costs of service are being paid. This means that, on average, cash working capital is being provided by MERC's customers. Negative cash working capital is subtracted from rate base so MERC does not receive a return on the funds provided by its customers.

In rebuttal testimony, Mr. DeMerritt agreed with Department witness Michelle St. Pierre's recommendations that, in future rate cases, (1) MERC provide a schedule that reconciles the expenses in the cash working capital to the expenses in MERC's test-year Income Statement, and (2) MERC's cash working capital schedule be based on number of days rather than percentages. Mr. DeMerritt also agreed with Ms. St. Pierre that an adjustment needs to be made to cash working capital, but the final cash working capital amount necessarily remains in flux until other items in the revenue deficiency calculation are resolved. Mr. DeMerritt included an updated calculation of MERC's current cash working capital position in his Rebuttal Exhibit___(SSD-4). MERC's rebuttal position is a Minnesota negative cash working capital of $3,330,603.

As a result of Department recommended adjustments to MERC's proposed test-year expenses, Department witness Michelle St. Pierre recommended that MERC's cash working capital be adjusted. In her surrebuttal testimony, Ms. St. Pierre agreed with Mr. DeMerritt that the final cash working capital amount remains in flux until other items in the revenue deficiency calculation are resolved. Ms. St. Pierre concluded that MERC and the Department agree regarding methodology and future rate case reporting.

ALJ

ALJ proposed findings 537 through 542.

In proposed findings 540 through 541, the ALJ noted that MERC:

- accepted the Department's recommendation that in future rate cases the Company provide a schedule that reconciles the expenses in the cash working capital to the expenses in MERC's test year income statement; and
- agreed with the Department's recommendation that in future rate cases MERC's cash working capital schedule be based upon the number of days, rather than specific percentages.

In proposed finding 542, the ALJ stated:

> 542. The Administrative Law Judge finds that MERC's Test Year Working Capital adjustment should be adjusted as described in Ms. St. Pierre's Direct Testimony. The Administrative Law Judge likewise finds that it is reasonable and prudent for MERC to recalculate the needed adjustment after the other items in the revenue deficiency calculation are resolved.

Decision Alternatives for Cash Working Capital

1. Adopt the ALJ's finding that MERC's Test Year Working Capital adjustment should be adjusted as described in Ms. St. Pierre's Direct Testimony and require Cash Working Capital to be updated to reflect the final decisions of the Commission. (MERC, DOC, ALJ)

2. Accept MERC's agreement and require MERC in future rate cases to provide a schedule that reconciles the expenses in the cash working capital to the expenses in MERC's test-year Income Statement.

3. Accept MERC's agreement and require MERC in future rate cases to base its cash working capital schedule on number of days rather than percentages.

(Note: These decision alternatives correspond to alternatives 68, 69 and 70 on the deliberation outline.)

<u>Reference to Record</u>
MERC Ex. 19, DeMerritt Direct at pp. 33-40, SSD-21.
MERC Ex. 24, DeMerritt Rebuttal at pp. 12, SSD-4.
DOC Ex. 217, St. Pierre Direct at pp. 50-52.
DOC Ex. 218, Attachments to St. Pierre Direct, MAS-8, MAS-8a.
DOC Ex. 219, St. Pierre Surrebuttal at pp. 43-44.
ALJ Report at pp. 80-81.

Other Gas Revenue - Miscellaneous Service Receipts

PUC Staff: Sundra Bender

In its November 27, 2013 NOTICE AND ORDER FOR HEARING at page 2, the Commission requested that the parties address MERC's test year forecast for late payment and other revenues in their prefiled direct testimony.

Volume III of MERC's filing included the following schedule of late payment and other revenues:

Minnesota Energy Resources Corporation
Docket No. G011/GR-13-617
Informational Requirements
Document 5
Schedule C-4

Line No.	Description	Reference	Historic 01/01/12 - 12/31/12	Adjustments	Projected 01/01/13 - 12/31/13	Adjustments	Proposed 01/01/14 - 12/31/14
1	487 Late Payment Revenues	General Ledger	416,284	108,716	525,000	-	525,000
2	488 Miscellaneous Service Revenues	General Ledger	167,218	(17,218)	150,000	-	150,000
3	493 Rent From Gas Property	General Ledger	31,356	22,644	54,000	-	54,000
4	495 Other Gas Revenue	General Ledger	9,243,378	(29,913,326)	(20,669,948)	20,700,418	30,470
5	496 Provision for Rate Refunds	General Ledger	(2,409,684)	2,409,684	-	-	-
6	**Total Other Revenue**		7,448,552	(27,389,500)	(19,940,948)	20,700,418	759,470
7	**Direct Assigned to MERC-Minnesota**		7,448,552	(27,389,500)	(19,940,948)	20,700,418	759,470
8	**Direct Assigned to MERC-Michigan**		-	-	-	-	-

Additionally, Volume III of MERC's filing at Information Requirements Document 6 states:

> Non-Tariff Revenues were forecasted based on historical trends, and inclusive of the $9,710 plus carrying costs credit to customers as ordered in Docket No. G007,011/GR-10-977.

Department witness Lerma La Plante reviewed MERC's calculation of test year revenue from miscellaneous service revenue (account 488) and stated that the test-year amount is based on year-to-date actual as of July 2012, annualized for the full year of 2012 and rounded to a higher number based on 2011 full-year actuals. Ms. La Plante expressed concerns with MERC's methodology and recommended that the test year other revenue from miscellaneous service revenues be increased by $51,493 [from $150,000 to $201,493]. The Department testified that this adjustment more reasonably averages the annual revenue over a four-year period of historical data (2010-2013), rather than the Company's method which is based on annualizing only seven months of 2012 actual data for the months of January through July, 2012.

In his rebuttal testimony, MERC witness Seth DeMerritt agreed with Ms. La Plante's recommended adjustment to test year miscellaneous service revenues.

ALJ

ALJ proposed findings 512 through 516.

In proposed finding 516, the ALJ found that an increase of $51,493 to MERC's test-year other revenue from miscellaneous services is appropriate and proper in this rate case.

Staff Comment

This issue is resolved between MERC and the Department. No other party offered testimony on this issue.

No party provided testimony explaining the $20 plus million dollar adjustments to "Other Gas Revenue." The Commission may wish to consider requiring that, in future rate cases, MERC provide direct testimony explaining all large differences between base year and test year data, regardless of whether the differences are in rate base, income, or expenses.

Decision Alternative for Other Gas Revenue

1. Adopt the ALJ's finding that an increase of $51,493 to MERC's test-year other revenue from miscellaneous service is proper in this rate case.

2. Require MERC to provide direct testimony in future rate cases explaining all large differences between base year and test year rate base, other income, and expense data.

(Note: These decision alternatives correspond to alternatives71 and 72 on the deliberation outline.)

Reference to Record
MERC Ex. 24, DeMerritt Rebuttal at pp. 15.
DOC Ex. 215, La Plante Direct at pp. 2-3, LL-3.
DOC Ex. 216, La Plante Surrebuttal at pp. 2.
ALJ Report at pp. 76-77.

Incentive Pay

PUC Staff: Sundra Bender

MERC has agreed with the Department to reduce its proposed test year executive compensation by $27,857 and to retain MERC's existing incentive compensation refund mechanism at the approved test-year level.[203]

Non-executive incentive plan
MERC witness Noreen Cleary states in her direct testimony that MERC's Non-executive incentive plan remains substantially the same in design as the 2011 and 2012 plans and a similar design is currently being developed for the 2014 plan. According to Ms. Cleary, the plan uses metrics focused on providing benefits in the form of reduced cost of service, greater efficiencies

[203] MERC Ex. 24, DeMerritt Rebuttal at 8 and 14.

in operations, increased customer satisfaction and improved reliability.[204] The plan uses four performance measures: Cost Management (non-fuel O&M Expense)-50%; Employee Safety-15%; Customer Satisfaction-15%; Reliability-20%. Ms. Cleary stated "Our operational measures are focused on improving services delivered to customers including cost control of expenses that impact their rates."[205] Participants include MERC non-union non-executive employees, as well as employees of IBS.

MERC proposes to recover 100% of the non-executive incentive plan costs because the plan "contains measures designed exclusively to provide benefits to customers by encouraging the achievement of operational goals focused on maintaining or reducing costs and improving reliability and service."[206]

MERC witness Seth DeMerritt stated in his direct testimony that the 2014 incentive costs for non-executive employees was calculated at the target level expense. Mr. DeMerritt, also filed direct Exhibit_____(SSD-16) which showed the calculation of a Known and Measurable decrease associated with incentives. According to Mr. DeMerritt, proposed test year total incentive pay (executive and non-executive) decreased from 2012 costs by $286,221, from $1,545,708 in 2012 to $1,259,487 in the test year.[207]

Executive Incentive Plan (Issues Matrix No. 18)

MERC initially proposed that 30% of Executive Incentive plan pay be included in the test year.[208] 10% uses the same Safety metric, and 10% uses the same Customer Satisfaction metric, as used in the MERC Non-Executive Incentive Plan. The final 10% uses an Environmental metric-which supports MERC's efforts to reduce annual emissions of carbon dioxide and other greenhouse gases by implementing energy efficiency and conservation activities that will reduce greenhouse gas emissions from the energy MERC uses as well as through improvements in the processes to generate and transmit natural gas with reduced greenhouse gas emissions.

MERC witness Seth DeMerritt stated in his direct testimony at page 24 that executive employee incentives for the test year were included at 30% to be consistent with the costs approved in Docket No. G007,011/GR-10-977.

The remaining 70% is associated with an Earnings per Share measure and is not included in the proposed test year costs.[209]

Department witness Michelle St. Pierre stated in her direct testimony that MERC provided, in response to DOC Information Request No. 153, a listing by number of 23 IBS and MERC employees that had incentive pay in the test year that exceeded base pay by more than 15% of their base pay totaling $185,709. The Company limited the amount of incentive compensation for these employees in the test year to 30% or $55,713.[210]

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[204] MERC Ex. 13, Cleary Direct at 2.
[205] Ibid at 7.
[206] Ibid at 11.
[207] MERC Ex. 19, DeMerritt Direct at 24; and (SSD-18) at 3-4; and MERC Ex. 20 at (SSD-16).
[208] MERC Ex. 13, Cleary Direct at page 12. MERC Ex. 19, DeMerritt Direct at page 24.
[209] MERC Ex. 13, Cleary Direct at page 12.
[210] DOC Ex. 217, St. Pierre Direct at 36.

To be consistent with recent decisions in Xcel Energy's electric general rate cases, Docket Nos. E002/GR-12-961 and E002/GR-10-971, Ms. St. Pierre recommended that the Commission cap MERC's test year incentive pay at 15 percent. To reflect the effect of this recommendation, she recommended that the Commission reduce A&G Expense by $27,857 ($55,713/2) for the executive incentive compensation costs.[211]

Ms. St. Pierre also recommended that MERC retain its existing incentive compensation refund mechanism, which provides customer refunds in the event that the incentive compensation payouts are lower than the test-year level approved in rates. She further recommended that the Commission's Findings of Fact, Conclusions and Order in the current docket specifically state the amount of incentive compensation approved in the test year.[212]

In his rebuttal testimony at page 8, Mr. DeMerritt agreed with Ms. St. Pierre's adjustment to reduce administrative and general expense by $27,857 for executive incentive pay.

MERC also agreed with Ms. St. Pierre's recommendation that MERC retain the existing incentive compensation refund mechanism, but requested that the calculation of the refund beginning with test year 2014, be based on the incentive compensation and customer counts approved in this rate case docket.[213]

In surrebuttal testimony, Ms. St. Pierre concluded that the executive incentive compensation issue is resolved between MERC and the Department.[214]

ALJ

ALJ proposed findings 338 through 359.

The ALJ stated the following in proposed findings 357 through 359:

> 357. The Administrative Law Judge finds that administrative and general expense should be reduced by $27,857 with respect to executive incentive compensation.
>
> 358. The Administrative Law Judge recommends that the Commission retain the current refund mechanism, under which the Company will return the funds to ratepayers in the event incentive compensation payouts are lower than the approved test-year level.
>
> 359. The Administrative Law Judge further recommends that the Commission's Findings of Fact, Conclusions and Order direct that any refunds from the incentive compensation refund mechanism be calculated beginning with the 2014

[211] Ibid at 37.
[212] Ibid.
[213] MERC Ex. 19, DeMerritt Direct at page 14.
[214] DOC Ex. 219, St. Pierre Surrebuttal at page 35.

test year, based upon the incentive compensation and customer counts approved in this docket.

Staff Comment

Currently MERC is required to refund any incentive compensation costs included in the 2011 test year revenue requirement of MERC's prior rate case that are not paid out in a particular year. MERC is authorized to track the annual amounts to be refunded and make the refunds only after they reach $1 per customer. MERC is also currently required to make an annual compliance filing within sixty days after the incentive compensation awards are or would have been paid and must include in its compliance filing sufficient information to determine whether a refund is required and, if so, the amount of the refund. Further, MERC is currently required to use a per dekatherm refund mechanism with any such refund.

Staff believes that in agreeing with the Department's recommendation to retain its existing incentive compensation refund mechanism at the new approved test-year 2014 level, MERC is also agreeing to continue the currently required annual compliance reporting requirements. However, the Commission may wish to clarify this point.

Staff notes that the Department recommended that the Commission's Finding of Fact, Conclusions and Order specifically state the amount of incentive compensation approved in the test year. However, neither party provided the number they want approved. Staff believes that after the agreed upon adjustment to executive incentive pay included in the test year, the total amount (Minnesota and Michigan, executive and non-executive) of incentive pay for the 2014 test year is $1,231,630, or $1,259,487 minus $27,857. The Commission may wish to confirm this.

Decision Alternatives – Incentive Pay

1. Adopt the ALJ's finding that administrative and general expense should be reduced by $27,857 with respect to executive incentive compensation. (DOC, MERC, ALJ)

2. Retain the existing refund mechanism, with the existing reporting requirements, under which MERC will return the funds to ratepayers in the event incentive compensation payouts are lower than the approved test-year level.

3. Require that any refunds from the incentive compensation refund mechanism be calculated beginning with the 2014 test year, based upon the incentive compensation and customer counts approved in this docket.

4. Approve total test year incentive compensation of $1,231,630. [The Commission may wish to confirm that this is the correct number.]

(Note: These decision alternatives correspond to alternatives 73 through 76 on the deliberation outline.)

Reference to Record

MERC Ex. 19, DeMerritt Direct at pp. 24, (SSD-18) at 3-4.
MERC Ex. 20, DeMerritt Exhibit SSD-16.
MERC Ex. 13, Cleary Direct at pp. 1-13.
MERC Ex. 24, DeMerritt Rebuttal at pp. 8 and 14.
DOC Ex. 217, St. Pierre Direct at pp. 35-37.
DOC Ex. 219, St. Pierre Surrebuttal at pp. 34-35.
MERC Initial Brief at pp. 63-64.
DOC Initial Brief at pp. 123-124.
ALJ Report at pp. 53-56.

Conservation Improvement Program (CIP)

Uncollected CCRC revenues from prior years (Uncontested)

PUC Staff: Bob Brill

Introduction

MERC acquired Aquila's Minnesota assets in July 2006. Prior to filing its Docket No. 10-977 rate case, MERC discovered certain customers who were considered CIP exempt for billing purposes, but had not received a CIP exemption from the Department of Commerce. The Commission dealt with this issue in its July 13, 2012 Order.

This issue has been resolved between the Department and MERC. No other party offered testimony on the issue.

Background

In its 10-977 rate case, MERC discovered customers were incorrectly considered CIP exempt for billing purposes, but had not received a CIP exemption for the Department of Commerce. These customers had not been billed MERC's CCRC or CCRA factors from the inception of MERC's ownership, July 2006. The customers were incorrectly classified as CIP exempt. MERC discovered and self-reported the CIP billing error.

In its July 13, 2012 Order,[215] the Commission required MERC to fund its CIP account for the unbilled CCRC and CCRA revenues from July 1, 2006 to the date of customers' CIP exemption; approximately $1 million was credited to MERC's CIP tracker account. The funding reinstated the CIP account to its proper level as if the customer had been properly billed. MERC did not apply its overall rate of return, interest, to the amount. The Commission stated that MERC brought this mistake to its attention without Commission intervention and based on the Department's recommendation did not assess interest to the CIP amount.

In this docket, MERC discovered another customer who was incorrectly not billed CIP charges since its July 2006 inception, Northshore Mining.

In its interim rate briefing papers, PUC staff's initial review of MERC's rate case raised certain concerns, which the Commission addressed in its Order.

The November 27th Commission Order[216] requested the following additional information:

> III. Supplemental Filings
>
> 1. Supplemental direct testimony reflecting the calculation of the applicable conservation cost recovery charge (CCRC) and conservation cost recovery adjustment (CCRA) charges since the inception of its ownership, July 2006. MERC shall also provide the applicable Northshore volumes, CCRC and CCRA

[215] Docket No. 10-977

[216] Docket No. 13-617 - November 27, 2013 Commission Order - NOTICE AND ORDER FOR HEARING

rates, and the CCRC and CCRA amounts, by month for the stated period of time, July 2006 through December 31, 2013.

Introduction to the Issues

Commission Order[217] requirements:

1. Calculation of Northshore CCRC and CCRA charges since the inception of MERC ownership, July 2006.

MERC

In MERC's Direct Testimony,[218] it discusses the Northshore Mining (Northshore)[219] CIP billing error, where Northshore was **not** properly billed CIP charges since the inception of ownership, July 1, 2006. MERC's direct testimony does not include any applicable volumes, rates, or CCRC and CCRA amounts associated with the billing error. [220] MERC stated that its test year CIP schedules were prepared assuming Northshore was granted its CIP exemption.[221]

In its December 26, 2013 Supplemental Direct Testimony, MERC addressed the Commission Order requirements. MERC provided the uncollected CCRC and CCRA amounts since July 2006, which totaled $2.5 million. [222]

MERC stated that it will absorb any un-collected amounts and not seek the one year back payment of CIP charges allowed by the billing error rules.[223]

In its rebuttal testimony, MERC agreed with the Department's CIP billing error recommendations and pledged to complete a series of reviews to prevent the recurrence of similar errors.[224]

Department

In its Direct Testimony[225], the Department recommended that the Commission require MERC to credit the CIP tracker for un-collected amounts (CCRC and CCRA) from July 2006 through December 2013 before Northshore's CIP exemption was effective January 1, 2014.[226] This recommendation is consistent with MERC's direct testimony statements.[227]

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[217] November 27, 2013 Commission Order - NOTICE AND ORDER FOR HEARING

[218] See Seth DeMerritt Direct Testimony, p. 44, lines 10-21

[219] Northshore is a Super Large Volume transportation customer whose gas is directly supplied by Northern Natural Gas's pipeline, but had not been exempted from paying CIP charges. Northshore is considered a by-pass threat.

[220] Upon discovery of this error, MERC notified Northshore and Northshore petitioned for a CIP exemption with the Commissioner of the Department of Commerce which was approved effective on January 1, 2014

[221] MERC Ex. 19 DeMerritt Direct Testimony at 44, lines 20-21

[222] MERC provided the required information in Supplemental Direct Exhibits, SSD-1, SSD-2, and SSD-3. SSD-2 and SSD-3 have been marked as "*Trade Secret.*"

[223] MERC Ex. 19 DeMerritt Direct Testimony at 44, lines 16-17

[224] MERC Ex. 24, DeMerritt Rebuttal at pp. 8 and 13-14 and EVIDENTIARY HEARING TRANSCRIPT, at 36-37 (DeMerritt)

[225] See Department Ex. 217, St. Pierre Direct at pp. 17-21

[226] Docket Nos. E015/CIP-13-852 and G011/CIP-13-853 - In the Matter of the Petition of Northshore Mining for Conservation Improvement Program Exemption

[227] MERC Ex. 19 DeMerritt Direct Testimony at 44, lines 16-17

Contrary to its Docket No. 10-977 recommendation not to calculate related interest on the un-collected CIP amount, the Department recommended that the Commission require MERC to add a one-time carrying charge on the un-collected CIP balance at MERC's approved overall rate of return during the billing error period.

The Department stated:

> MERC had ample opportunity to verify whether it appropriately charged all non-exempt CIP customers by means of internal audit and/or the Vertex audit of the billing system. As stated by MERC, "No audit tests specifically related to CIP issues were explicitly identified in the Statement of Work (SOW), and so to the extent that any billing errors related to CIP were not discovered in the audit process, no specific CIP issues were specifically sought out." MERC Ex. ___ at 4 (DeMerritt Supplemental Direct).

The Department further recommended that the Commission require MERC to file a report on the funding of the un-collected CIP amounts in its final rates compliance filing in this rate case.

ALJ
ALJ proposed findings 587-596

In its proposed finding 596, the ALJ found that due to MERC's absorption of the under-recovery of CIP charges from Northshore, its crediting the CIP tracker for these uncollected amounts and the completion of improvements to its billing system, the Commission should approve MERC's overall approach to uncollected CIP expense in this rate case.

PUC Staff Comment
PUC staff agrees with the Department's and ALJ's recommendations on the treatment of the uncollected CIP revenues associated with Northshore Mining billing errors since July 2006.

Decision Alternatives

1. Adopt the Administrative Law Judge and the Department recommendations on the treatment of uncollected CIP revenues associated with Northshore Mining and required the following:

    a. require MERC to credit the CIP tracker for un-collected amounts (CCRC and CCRA) from July 2006 through December 2013 before Northshore's CIP exemption was effective January 1, 2014; and

    b. require MERC to add a one-time carrying charge to the un-collected CIP revenue balance at MERC's approved overall rate of return during this period; and

c. require MERC to report the funding of the un-collected CIP amounts in its final rates compliance filing in this rate case. [MERC, Department, ALJ, PUC staff]

(Note: This decision alternative corresponds to alternative 77 on the deliberation outline.)

Reference to Record
MERC Ex. 19, DeMerritt Direct p. 44
MERC Ex. 24, DeMerritt Rebuttal at pp. 8 and 13-14
See Department Ex. 217, St. Pierre Direct at pp. 17-21
Evidentiary Hearing Transcript, at 36-37 (DeMerritt)
ALJ Report pp. 86-87

Adequacy of Vertex Billing Audit (PUC Notice and Order for Hearing)

PUC Staff: Bob Brill

Introduction
In Docket No. 10-977, MERC self-reported three CIP billing errors where its customers were considered CIP exempt, but the customers had not received a CIP exemption from the Department of Commerce. In this docket, MERC self-reported another customer who was considered CIP exempt for billing purposes, but had not received a CIP exemption from the Department. The CIP billing errors has led PUC staff to question the adequacy of the Vertex audit. The current CIP billing error is addressed by PUC staff in the Un-collected CIP revenues from prior year's discussion.

Background
In its Order[228] for this rate case, the Commission requested that MERC provide certain information pertaining to adequacy of its Vertex billing audit with respect to CIP and other billing errors in its supplemental direct testimony within 30 days from the Order date.

The Commission ordered the following:

> III. Supplemental Filings
>
> Within 30 days of this Order, the Company shall file the following supplements to its direct testimony:
>
> > 2. Additional information on the adequacy of the Vertex billing audit with respect to finding CIP-related and other billing errors. Parties shall also address the adequacy of the Vertex billing audit in finding these errors.

MERC – Supplemental Direct[229]

[228] November 27, 2013 Commission Order - NOTICE AND ORDER FOR HEARING
[229] MERC Ex. 21, DeMerritt Supplemental Direct at p. 4

MERC addressed the Commission Order requirements by stating:

> …….in the May 1, 2013 briefing papers filed in Docket G007,011/GR-10-977, MERC worked with the Department of Commerce ("DOC") and the Office of the Attorney General on a Statement of Work ("SOW") related to an audit of the Vertex billing system. No audit tests specifically related to CIP issues were explicitly identified in the SOW, and so to the extent that any billing errors related to CIP were not discovered in the audit process, no specific CIP issues were specifically sought out. The results of the billing audit were submitted on October 12th, 2012 with no significant issues…..

MERC Rebuttal

In its rebuttal testimony, MERC pledged to complete a series of reviews to prevent the recurrence of similar CIP exemption billing errors.[230]

ALJ

The ALJ did commented that MERC did meet the November 27th Order requirements, but did not make a recommendation on the MERC proposed review process.

PUC Staff Comment

PUC staff believes that the Docket No. 10-977 SOW was executed within the parameters designed by the parties. The CIP billing errors were not specifically listed as part of the original Vertex audit SOW design.

However, in MERC's last two rate cases,[231] the CIP billing errors have been self-reported by MERC; staff commends MERC for reporting these billing errors. In both dockets, MERC has assured PUC staff that the Vertex billing system does not have any further CIP billing errors. Yet, these CIP billing errors have continued to appear in MERC's rate cases.

The CIP billing errors occurrences have caused PUC staff concern that the Vertex billing system might include additional CIP billing errors; where MERC customers have erroneously been considered CIP exempt when the customers were not.

In its rebuttal testimony, MERC has agreed to complete a series of reviews to prevent the recurrence of similar CIP exemption billing errors. The Commission may wish to consider an additional audit investigation on whether further CIP billing errors exist in the Vertex billing system or, at the very least, require MERC to make a compliance filing in this docket reporting the results of its billing system review.

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[230] MERC Ex. 24, DeMerritt Rebuttal at pp. 8 and 13-14 and EVIDENTIARY HEARING TRANSCRIPT, at 36-37 (DeMerritt)

[231] Docket No. 10-977 and 13-617

Decision Alternatives:

1. Adopt MERC's pledge to perform a series of tests to review its CIP billing process. or

2. Adopt MERC's pledge to perform a series tests to review its CIP billing process and require MERC to submit a compliance filing in this docket reporting its findings from this review process. or

3. Require MERC to have a third party auditor develop an audit methodology to review the Vertex billing system for CIP and other billing errors. or

4. Consider MERC's previous Vertex billing system responses as sufficient and further consider prior Commission precedent as a deterrent to MERC to police its billing system, and require no further action.

(Note: This decision alternative corresponds to alternatives 78 through 81 on the deliberation outline.)

Reference to Record
MERC Ex. 21, DeMerritt Supplemental Direct at p. 4
MERC Ex. 24, DeMerritt Rebuttal at pp. 8 and 13-14
Evidentiary Hearing Transcript, at 36-37 (DeMerritt)

Conservation Improvement Program (CIP) Expenses (Uncontested & Contested)

PUC Staff: Bob Brill

Introduction

The establishment of the appropriate Conservation Cost Recovery Charge (CCRC) factor is dependent on the test year CIP expense amount and the test year sales volumes approved by the Commission in this rate case. The calculation of the CCRC factor calculation includes all non-CIP exempt customers' sales and transportation volumes. The other CIP-related issues raised in this rate case will require adjustments to MERC's CIP tracker accounts and will not directly affect the CCRC base factor.

Background

Prior to Docket No. G007,011/GR-08-835, MERC, and its predecessor Aquila, had CCRC factors established in rate cases, used CIP tracker accounts to record CIP revenues and expenses, but did not have an annual adjustment mechanism for recovering the difference between CIP expenditures and revenues. Instead, the tracker balances were trued up and recovered through rate cases.

In its 08-835 rate case, MERC received Commission approval to update the CCRC factors to reflect its annual CIP program costs plus the balances remaining in the Company's CIP tracker accounts, amortized over three years. Further, MERC received Commission approval to implement a Conservation Cost Recovery Adjustment (CCRA) mechanism. This permitted MERC to annually adjust its CCRA factor for any over/(under)-recovery, DSM incentive, and any other changes that occur outside of a rate case.

The final rates from the 08-835 rate case were effective January 1, 2010. The initial CCRA was set at $0.0000. MERC's first annual adjustment filings were made in Dockets G-011/M-10-407 (PNG) and G-007/M-10-409 (NMU). These CCRA rates were implemented on November 1, 2010.[232]

In the Minnesota Laws 2011[233], the Minnesota legislature enacted legislation that established broad categories of large customers who could request exemption from CIP-related charges. One change was to allow qualifying large customers to request exemption based on their natural gas usage levels. Under the prior CIP exemption statutes, eligibility was determined by electricity demand levels, but customers who qualified and were approved for exemption by the Commissioner of the Department of Commerce automatically had their natural gas usage exempted also.

A number of MERC's large customers were CIP exempt prior to the 2011 statutory changes due to their high levels of electric demand. A number of additional MERC customers became CIP-exempt effective January 1, 2012 under the 2011 law, including many, but not all, of the customers covered by the CCRA suspension in dockets 10-407 and 10-409.

The table below summarizes the various customer exemptions currently established in statute:

Exemption Category	*Date Enacted*	*Statutory Definition*	*Summary Description*	*Summary of Conditions*	*Decision-maker*
Large Customer Facility-Electric	1999 modified 2011	216B.241, subd. 1 (i) (1)	Customer facility with electric demand ≥ 20 MW	-Facility has taken reasonable measures to identify, evaluate and implement energy conservation & efficiency improvements -If qualifies for electric, gas usage eligible	DOC
Large Customer Facility –Gas	2011	216B.241, subd. 1 (i) (2)	Customer facility using ≥ 500,000 MCF annually	-Facility has taken reasonable measures to identify, evaluate and implement energy conservation & efficiency improvements -If qualifies for gas, electric usage eligible	DOC

[232] On December 1, 2010, MERC submitted "emergency" petitions in Dockets 10-407 and 10-409, requesting a suspension of the CCRA surcharge for certain large customer classes. MERC contended that the rate impact of the recently-implemented CCRA for certain customers was creating financial hardship and could cause some of the customers to by-pass MERC's distribution system.
On January 24, 2011, the Commission issued an Order allowing MERC to suspend the CCRA for the Large Volume Interruptible Flex, Super Large Volume Joint Mainline customer classes with certain conditions and requiring additional filings. Staff noted that the CCRA suspension was not intended to be a permanent resolution of the issues, and that the CCRC was not suspended for these customers.
On May 9, 2013, the Commission issued its ORDER ENDING SUSPENSION, EXEMPTING ELIGIBLE CUSTOMERS FROM RATE RECOVERY OF CONSERVATION COSTS, SETTING REFUND AND REPAYMENT REQUIREMENTS, AND REQUIRING FURTHER FILINGS.
[233] See Minn. Laws, Chapter 97, Sections 18, 19, 21 and 30

Exemption Category	*Date Enacted*	*Statutory Definition*	*Summary Description*	*Summary of Conditions*	*Decision-maker*
Commercial Gas Customer	2011	216B.241, subd. 1a (c)	Customer who can bypass the LDC	-Customer demonstrates capability to bypass LDC distribution system by obtaining gas directly from supplier not regulated by PUC -Gas usage only	DOC
Large Energy Facility	2007	216B.241, subd. 1 (j)	Electric generating facility ≥ 50 MW	-Facility is an electric generator as defined in 216B.2421, subd.2 (1) -Gas usage only	PUC

In Docket No. G-007,011/GR-10-977, the Commission approved MERC's request to update its CCRC factor, but did not address MERC's CCRA factor in that proceeding. The Commission further addressed MERC's request to consolidate its current MERC-PNG and MERC-NMU CCRC factors into one charge. The Commission approved MERC's CCRC consolidated request effective July 1, 2013; the approved factor was $0.01513.[234]

In its initial Order[235] for this rate case, the Commission requested that MERC provide certain information pertaining to its CIP program in supplemental direct testimony within 30 days from the Order date.

> The Commission required MERC to provide the following information:
>
> 1. Additional information regarding the Company's tracking and handling of CIP expenses in the development of the test year operating expenses.

Introduction to the Issues

MERC and the parties have addressed several issues related to MERC's CCRC, CCRA, and CIP cost recovery. Most of the issues were not contested or the parties have reached agreement during the course of the proceeding. Staff will discuss the following uncontested and contested issues:

<u>Uncontested CIP Issues</u>

A. Commission Order[236] requirements:
    - MERC's tracking and handling of CIP expenses in the development of the test year operating expenses
B. Minn. Stat. 216B.16, subd.1 requirements
C. Test Year CIP Expenses
D. CCRC factor calculation for final rates
E. Department's adjusted sales forecast projection
F. Unamortized Balance in the CIP Tracker Account

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[234] See MERC Docket No. G-007,011/GR-10-977, Compliance Filing dated April 12, 2012, Attachment E
[235] November 27, 2013 Commission Order - NOTICE AND ORDER FOR HEARING
[236] November 27, 2013 Commission Order - NOTICE AND ORDER FOR HEARING

G. Carrying Charges in MERC's CIP tracker

Contested CIP Issues

H. Impact on Revenue Deficiency (Are CIP revenues and expenses revenue neutral for the purpose of determining MERC's revenue requirement?)

The ALJ addressed CIP-related issues in his Report on pages 82-90, Findings 552-613

MERC's tracking and handling of CIP expenses in the development of the test year operating expenses (Uncontested)

Introduction

In its briefing papers,[237] PUC staff stated that it is unclear from the record at this point whether the Company's proposed test year operating expenses include any other CIP related expenses. Staff recommended that, in order to have a clear record for the total amount of CIP expenses included in the proposed test year, the Commission request additional information regarding MERC's tracking and handling of CIP expenses in the development of the test year operating expenses.

This issue is uncontested.

MERC

In its Direct Testimony, MERC stated that its test year CIP expenses included in the initial petition were reflected at the 2013 CIP expenses approved in Docket No. 12-548[238] of $8,920,481. In its response to DOC Information Request 105[239], MERC stated that it agreed with the Department and should have used the 2014 CIP expenses of $9,396,422 for its test year O&M expenses that were approved in Docket No. 12-548.

ALJ

The ALJ does not make a recommendation on this issue.

PUC Staff Comment

PUC staff believes that MERC has satisfied the Commission March 27th Order requirements and no further action is necessary.

Decision Alternatives for the November 27th Commission Order requirements

1. Accept MERC's response as satisfying the Commission's March 27th Order requirements. or

[237] Dated November 7, 2013
[238] MERC's Triennial CIP Report
[239] MERC Ex. 21, DeMerritt Supplemental Direct at Exhibit SSD-3

2. Determine that MERC's response has not sufficiently satisfied the Commission's March 27th Order requirements.

(Note: This decision alternative corresponds to alternatives 82 and 83 on the deliberation outline.)

Minn. Stat. 216B.16, subd. 1 requirements (Uncontested)

Introduction

The Minnesota Legislature requires utilities to make certain CIP expenditures pursuant to Minn. Stat. § 216B.241, and it has established a requirement for cost recovery of these expenses in utility rates. Minn. Stat. § 216B.16, subd. 6b,[240] mandates recovery of CIP expenses in utility rates, and allows a public utility to file rate schedules providing for annual recovery of the cost of CIP programs.

Minnesota Statutes section 216B.16, subd. 1, states in relevant part that if a utility filing a general rate case does not have an approved conservation improvement plan on file with the Department, that utility must include, in its general rate case notice, an energy conservation plan pursuant to Minn. Stat. §216B.241.

This issue is uncontested.

MERC

MERC filed its triennial CIP plan in Docket No. 12-548 and it was approved by the Department on April 30, 2013. MERC's initial petition included O&M CIP expenses of $8,920,481.

Department

The Department stated that MERC has satisfied the requirements specified in Minn. Stat. §216B.16, subd. 1.

ALJ

The ALJ does not make a recommendation on this issue.

PUC Staff Comment

PUC staff agrees with the Department's conclusion that MERC has met Minn. Stat. §216B.16, subd. 1 requirements.

Decision Alternatives for Minn. Stat. 216B16, subd. 1 Requirements

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[240] Minn. Stat. § 216B.16, subd. 6b(a) allows utilities to recover costs of relevant conservation improvements; except as otherwise provided in this subdivision, all investments and expenses of a public utility…incurred in connection with energy conservation improvements shall be recognized and included by the commission in the determination of just and reasonable rates as if the investments were directly made or incurred by the utility in furnishing utility service.

1. Adopt the Department's finding that MERC has met the requirements of Minn. Stat. 216B.16, subd. 1.

(Note: This decision alternative corresponds to alternative 84 on the deliberation outline.)

Test Year CIP Expenses (Uncontested)

Introduction

As previously mentioned, the CCRC base factor is adjusted in every rate case. The Commission has previously approved this methodology.

This issue is uncontested.

MERC Direct[241]

MERC proposed to recover 2013 test year CIP program expenses of $8,920,481 as shown on Exhibit (SSD-24) from it 2013-2015 CIP Triennial plan.[242] The test year expenses include the 2013 CIP program costs approved by the Commissioner of the Department of Commerce.

MERC stated in the Department's Information Request No. 105[243] that it was under the impression that it was to use the approved 2013 CIP expenses for its test year projection.

MERC Rebuttal

After its review, MERC stipulated to use the Department recommended 2014 proposed CIP expenses of $9,396,422 and MERC agreed with the Department's recommendation.

Department Direct[244]

The Department disagreed with MERC's initial use of the approved 2013 CIP expense as its test year cost level. The Department proposed that the CCRC factor should be based on MERC's approved 2014 Triennial CIP report cost level of $9,396,422 for an adjustment increase of $475,941.[245]

The Department recommended that MERC update its test year CIP costs to 2014 CIP Triennial Plan level as opposed to 2013.

Department Surrebuttal

The Department concluded that MERC and the Department are in agreement.

ALJ

In findings 581, the ALJ agreed with the parties and recommended a test year CIP expense level of $9,396,422.

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[241] See MERC Ex. 19, DeMerritt Direct at pp. 42-43
[242] See Docket No. G007,G011/CIP-12-548 and MERC Ex. 19 DeMerritt Direct at pp. 41-42
[243] Department Ex. 217 St. Pierre Direct at Exhibit MAS-15
[244] Department Ex. 217 St. Pierre Direct at p. 13
[245] Department Ex. 217 St. Pierre Direct at Exhibit MAS-16

PUC Staff Comment

PUC staff agrees with the parties' recommendations that the 2014 test year CIP expenses should be $9,396,422.

Decision Alternatives for Test Year CIP Expenses

1. Adopt the ALJ finding that MERC recover $9,396,422 in test year CIP expenses.

(Note: This decision alternative corresponds to decision alternative 85 on the deliberation outline.)

CCRC Calculation for Final Rates (Uncontested)

This issue is uncontested.

MERC Direct[246]

The CCRC factor is a separate component of MERC's distribution rate charged to non-CIP exempt customers. In this docket, MERC initially proposed a CCRC factor of $0.02432 per therm.[247]

MERC stated its calculation is consistent with Commission precedent that was approved in its last rate case. MERC has calculated the CCRC factor on a volumetric basis by taking the CIP test year expenses and dividing by test year sales volumes less the volumes attributed to those customers who have opted out of CIP. This calculation method has been previously reviewed and approved.

MERC stated that it removed the volumes associated Northshore Mining (Northshore)[248] from the sales forecast used to calculate the CCRC factor since Northshore has been made CIP exempt effective January 1, 2014.

MERC Rebuttal

MERC agreed with the Department's recommendation. MERC stated that it is willing to update the CCRC in final rates based on the higher CIP expense and change in sales forecast from filing, along with making a CIP tracker balance adjustment.

Department[249]

The Department recommended that the Commission require MERC to report in its final rates compliance filing in the rate case, the calculation of the CCRC rate based on the Commission's Order regarding the level of CIP expenses divided by the approved level of sales.

The Department recommended the Commission approve a revised CCRC factor based on the Company's proposed volumetric method and test year sales approved by the Commission and to

[246] MERC Ex. 19 DeMerritt Direct at pp. 42-43
[247] See MERC Ex. 19, DeMerritt at Exhibit SSD-24
[248] See the below Northshore discussion on the uncollected CCRC revenues from prior years that resulted from MERC's billing error.
[249] See Department Ex. 217, St. Pierre Direct at p. 16

include in the calculation of the CCRC factor the sales forecast from all customers that are not exempted from CIP.

ALJ

In finding 567, the ALJ stated that MERC should report in its final rates compliance filing the calculation of the CCRC rate based upon terms of the Commission's Order.[250]

PUC Staff Comment

Staff agrees with the parties' recommendation on how to calculate the final CCRC factor.

Decision Alternatives for CCRC Calculation for Final Rates

1. Adopt the ALJ recommendation that the final rates compliance filing include the calculation of the CCRC rate based upon terms of the Commission's Order.

(Note: This decision alternative corresponds to alternative 86 on the deliberation outline.)

Effect of the Department's sales forecast projection (Uncontested)

This issue is uncontested

Department - Direct

The Department adjusted[251] MERC's sales forecast increasing it by 26,791,937 therms.

MERC Rebuttal

MERC has agreed with the Department's sales forecast adjustment.

Department Adjusted Sales Forecast in therms	MERC's Original Sales Forecast in therms	Increase/(Decrease) in therms
689,625,514	662,833,577	26,791,937

ALJ

In finding 613, the ALJ recommended that MERC should report in its final rates compliance filing the calculation of the CCRC rate based upon the Commission's Order, with respect to the level of CIP expenses divided by the level of sales approved by the Commission.

PUC Staff Comment

Staff agrees with the Department's adjusted sales forecast.

Decision Alternatives for the effect of the Department's sales forecast projection

1. Adopt the ALJ recommendation and approve the Department's adjusted sales forecast for calculating the final compliance report's CCRC factor.

[250] See Department Ex. 219, St. Pierre Surrebuttal at pp. 13-14 and Department Ex. 217, St. Pierre at pp. 15-17.
[251] See Department Ex. 212 Otis Direct at pp. 28-32 and Ex. LBO-12, pp. 1-2

(Note: This decision alternative corresponds to alternative 87 on the deliberation outline.)

Unamortized Balance in the CIP Tracker Account (CCRA) (Uncontested)

Introduction

As stated above, in Docket No. 08-835, MERC received Commission approval to establish a CCRA factor to flow-back/collect any over/under-collection that may occur when MERC's CCRC factor revenue collections are compared to actual expenses in its CIP tracker account. The CCRA factor is adjusted in MERC's annual petition, filed by May 1 of every year.

This issue is uncontested.

MERC Direct[252]

MERC stated that it is not seeking recovery of the unamortized balance in the CIP tracker accounts through its re-calculation of the CCRC base rate in this docket, but rather MERC proposed to recover this unamortized balance through the CCRA tracker mechanism.

MERC has stated that its current CCRA factors were approved by the Commission and have not been adjusted by interim rates in this docket.

MERC Rebuttal

MERC agreed to report the un-recovered CIP information its final rates compliance filing.

ALJ

The ALJ does not make a recommendation on this issue.

PUC Staff Comment

Staff agrees with the parties' proposal.

Decision Alternatives Unamortized Balance in the CIP Tracker Account (CCRA)

1. Allow MERC to keep its on-going CIP tracker balance within its CCRA tracker mechanism and do not require MERC to "roll-in" its CIP tracker balance into MERC's CCRC calculation.

(Note: This decision alternative corresponds to alternative 88 on the deliberation outline.)

Carrying Charge in MERC's CIP Tracker Account (Uncontested)

Introduction

In Docket No. 08-835, the Commission approved a CIP carrying charge at MERC's overall rate of return approved in that rate case. The carrying charge was a carried-over to Docket No. 10-977. This issue is uncontested.

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[252] See MERC Ex. 19, DeMerritt Direct at p. 43

MERC Direct[253]
MERC requested that the Commission approve a similar carrying charge for MERC's CIP tracker account balance equal to the overall rate of return approved in the current case.

MERC Rebuttal[254]
MERC agreed with the Department carrying charge recommendation.

Department Direct[255]
The Department recommended that the Commission require MERC to update its carrying charge at final rates determination. This is consistent with past Commission practice and should be updated to the approved overall rate of return.

ALJ
In findings 586, the ALJ recommends that the Commission should require MERC to update the CIP carrying charge used in the CIP tracker to the rate of return approved in this rate case.

PUC Staff Comment
PUC staff agrees with the recommendations of all the parties.

Decision Alternatives for Carrying Charges in MERC's CIP tracker

> 1. Adopt the ALJ recommendation to allow MERC to apply to its CIP tracker account carrying charges that are equal to the overall rate of return approved for MERC in this general rate case.

(Note: This decision alternative corresponds to alternative 89 on the deliberation outline.)

Impact on Revenue Deficiency (Are CIP revenues and expenses "revenue neutral"?) (Contested)

MERC Direct[256]
MERC stated that for revenue deficiency purposes, it has included the updated CIP costs, but has not adjusted revenues for an updated CCRC costs. Further, MERC stated that it was not "revenue neutral" in this docket

MERC stated that:

> In MERC's last rate case Docket No. G007,011/GR-10-977 MERC inputted revenues to offset the increase in CIP expenses due to an increased CCRC for interim rate purposes. This created a revenue neutral effect in interim rates for purposes of the increased CCRC,

[253] See MERC Ex. 19, DeMerritt Direct at p. 43
[254] See MERC Ex. 24, DeMerritt Rebuttal at p. 13
[255] See Department Ex. 217, St. Pierre Direct at p. 15
[256] See MERC Ex. 19 DeMerritt Direct at p. 43

> but did create some confusion among parties. Therefore, prior to this current rate case, MERC contacted Commission Staff to work on how to address the increase in the CCRC in interim rates. Commission Staff gave the guidance that MERC should include the increased expense in the interim rate calculation, so that is the approach MERC took in this current docket.

MERC Rebuttal[257]

MERC did not agree with the Department's recommended $3,758,090 adjustment. MERC stated that by imputing CIP revenues of $3,758,090 to offset the increase in CIP expense, the Department is effectively reducing MERC's revenue requirement based on revenue that will never be collected in its financial statements. MERC stated that its CIP revenue is in the revenue requirement because the test year sales revenue is calculated at present rates rather than forecasted final rates.

Further, at the evidentiary hearing, MERC explained that the Department's recommended CIP revenue increase incorrectly lowers the revenue deficiency while the CIP expenses actually increases. In other words, the Department is recommending an overall rate increase of $3.3 million, while CIP expenses alone are increasing $3.8 million. This has the effect of reducing rates $500,000 for all of MERC's other costs included in this case.[258]

Based on subsequent discussions between MERC and the Department following the submission of the Department's Direct Testimony, MERC understood that the Department's ultimate goal was to remove the CCRC from base rates completely, thereby allowing all CIP expenses to flow through the CCRA. In order to accomplish this, MERC understood the Department to propose that MERC remove all CIP expenses from the revenue deficiency. MERC would then seek recovery for any under-collection of CIP expenses via a separate docket filed for the CCRA.[259] MERC testified that it would not be opposed to this approach provided that the dockets related to the CCRA are finalized and an order is issued in a timely fashion. In addition, if changing the CCRC to $0.00000 were to occur in the current docket, MERC would request that its currently recommended CCRC of $0.02462 be added to the CCRA on January 1, 2015, or with implementation of final rates, whichever occurs later, so as not to delay the recovery of these expenses.[260]

MERC does agree with the Department recommendation to increase its test year CIP expense level from $8,920,481 to 9,396,422.[261] Further, MERC agreed to the Department's adjusted sales forecast.[262] Both of these adjustment resulted in MERC re-calculating its test year CCRC to $0.02462. [263]

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[257] See MERC Ex. 22, DeMerritt Rebuttal at pp. 5-6
[258] Evidentiary Hearing Transcript at 23 (DeMerritt) (May 13, 2014).
[259] See MERC Ex. 24, DeMerritt Rebuttal at 6
[260] See MERC Ex. 24, DeMerritt Rebuttal at 6 and Schedule SSD-1
[261] See MERC Ex. 24, DeMerritt Rebuttal at p. 7
[262] See MERC Ex. 24, DeMerritt Rebuttal at p. 7 and MERC Ex. 39, John Rebuttal at 13
[263] For calculation details, see MERC Ex. 24, DeMerritt Rebuttal at Exhibit SSD-1

MERC stated that it was currently charging in interim rates its filed position CCRC factor of $0.02432 and that the CIP revenue billed to customers is reflected as a credit in its CIP tracker account.[264] [265]

MERC further stated that by changing the interim CCRC factor from the filed level of $0.02432 to $0.02462 would require MERC to fund additional amounts to the CIP tracker account which could result in reducing any potential interim period refund to customers.

MERC stated that based on discussions between the Department and itself following the submission of the Department's Direct Testimony, it was MERC's understanding that the Department's ultimate goal was to remove the CCRC from base rates completely, thereby allowing all CIP expenses to flow through the CCRA in the CIP tracker account. In order to accomplish this, the Department proposed that MERC remove all CIP expenses from the revenue deficiency. MERC would then seek recovery for any over/under-collection of CIP expenses through a separate docket filed annually.

MERC stated that it would not be opposed to this approach provided that the dockets related to the CCRA are finalized and an order is issued in a timely fashion. In addition, if changing the CCRC in the distribution rate to $0.00000 were to occur in the this docket, MERC would request that its currently recommended CCRC of $0.02462 be added to the CCRA factor on January 1, 2015, or with implementation of final rates, whichever occurs later, so as not to delay the recovery of these expenses.

Department Direct[266]

The Department calculated its test year CIP revenues at $5,382,049, by taking the CIP applicable volumes of 355,720,357 therms times the 10-977 CIP rate of $0.01513. The Department then adjusted its CIP revenues by adding $256,283[267] which represented the CIP revenue caused by the sales forecast adjustment[268] for its adjusted test year CIP revenue of $5,638,332. By comparing its adjusted test year CIP revenues of $5,638,332 to its proposed test year CIP expense level of $9,396,422, the Department concluded that the test year CIP revenues did not equal MERC's revised test year CIP expense and MERC was not "revenue neutral" in its financial statements.

The Department was concerned that MERC was recovering additional CIP expense through its interim rates, but it appears that MERC failed to adjust its CCRC factor at January 1, 2014. The Department stated that this would artificially inflate MERC's revenue requirement deficiency.[269]

The Department recommended that MERC make its CIP revenues and expenses "revenue neutral" similar to how the base cost of gas is treated in the test year.[270] Specifically, the CIP

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[264] See MERC Ex. 24, DeMerritt Rebuttal at p. 7 and Exhibit SSD-2

[265] The CIP tracker account reflects a carry-over balance of the previous month and adds monthly CIP expenses to the balance and subtracts monthly CIP revenue collection to calculate the monthly ending CIP tracker account balance

[266] See Department Ex. 217 St. Pierre Direct at pp. 14-15 and Exhibit MAS-16

[267] See Department Ex. 212, Otis Direct at Ex. LBO-12, pp. 1-2

[268] MERC has agreed to the Department's adjusted sales forecast, see MERC Ex. 39, John Rebuttal at p. 13

[269] See Department Ex. 217 St. Pierre Direct at pp. 14-15

revenues should equal the CIP expenses; by doing this, the revenue requirement deficiency reflects no impact from CIP costs. The Department recommended that the Commission require MERC to increase its CIP Revenue by $3,758,090.[271] [272]

Further, the Department stated that in its final compliance filing in this rate case, MERC should assign or calculate the CIP revenues for the interim rate period and make a delayed lump sum credit to the CIP tracker.

Department Surrebuttal[273]
In response to MERC's rebuttal testimony, the Department continued to support its Direct Testimony position that CIP revenue and expense should offset each other so that the test year revenue deficiency is "revenue neutral", similar to how the cost of gas calculation works.[274] MERC continues to recommended to the Commission that MERC be require to increase its natural gas revenues by $3,758,090 for CIP revenues that will produce a revenue neutral position for CIP in MERC's revenue requirements.

The Department continued to recommend that CCRC revenues be accounted for similar to how the cost of gas is accounted for in base rates since both the cost of gas and CIP costs are in trackers. The Department recommended using the same method for CIP costs as used for gas costs, since both cost categories have trackers that run through rate cases and subsequent to rate cases. The new CCRC should be implemented at the beginning of a rate case as well as at final rates. The Department's reasoning for its recommended approach was for consistency since the more consistently that the trackers are treated, the less confusion and time that needs to be spent on auditing the tracker.

As previously stated above by MERC, it increased its CCRC recovery at the beginning of the interim rate period, therefore, MERC is currently collecting the higher CCRC revenues and the CCRC factor will be adjusted again at the conclusion of the rate case. MERC does not need to calculate additional revenue requirements for the CIP revenues. Finally, MERC is allowed to have a tracker that keeps track of revenues and costs, which forms the basis of rates to true-up any difference between these amounts.

In MERC's Direct Testimony, it stated the Department's ultimate goal was to remove CCRC from base rates completely, thereby allowing all CIP revenues and expenses to flow through the CCRA tracker mechanism. The Department stated that this was not its intention, but to merely set CIP revenues equal to the CIP expenses. The Department reasoning for not recommending

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[270] The base cost of gas revenues are clearly stated in MERC's revenue schedule and in its financial statements, thus it is easy to determine if the base cost of gas revenue and expenses are "revenue neutral"
[271] Test year CIP expenses of $9,396,422 minus CIP revenues of $5,638,332
[272] See Department Ex. 217 St. Pierre Direct at Ex. MAS-16
[273] See Department Ex. 219, St. Pierre Surrebuttal at pp. 11-19 and Exhibit MAS-S-16
[274] In the cost of gas calculation, the gas revenues equal the gas expense, thus, there is no impact on the revenue deficiency. MERC does not include the cost of gas in the revenue requirement because the test-year sales revenue related to gas costs is matched to the projected gas costs rather than calculated at present rates. CIP, on the other hand, is in the revenue requirement because the test-year sales revenue is calculated at present rates rather than forecasted final rates. A new base cost of gas rate is implemented at the beginning of a rate case as well as at final rates, CIP should receive similar treatment.

this method at this time was because it is easier to understand and accept if the CCRC is determined similar to way that the base cost of gas is determined.

The Department accepted MERC's explanation that it had adjusted its CCRC factor at the beginning of the interim period.[275]

The Department recommended that the Commission require MERC to change the CCRC factor for funding the CIP tracker at the beginning of interim rates and again at final rates in future rate cases. The Department stated that this recommendation will keep the CIP tracker in sync with the change in interim rates as well as for final rates.

In its rebuttal testimony, MERC stated that if it re-calculates the CCRC factor should consistent with the test year CIP expenses of $9,396,422 and the Department's adjusted sales forecast, the CIP account could be under-funded because of the CCRC factor change. If this under-collection occurs, MERC proposed to increase the CIP account balance by reducing any refunds due to its customers after the interim rate period ends. The Department stated that this methodology seems reasonable.

Department Conclusions:
MERC and the Department agree on the following items:

- require MERC to increase CIP expense by $475,941 to a CIP expense level of $9,396,422;
- update, at the time of final rates, its CIP tracker carrying charge based on the overall rate of return approved in this general rate case;
- report in its final rates compliance filing, the calculation of the CCRC rate based on the Commission's Order; and
- change the CCRC rate at the beginning of interim rates and again at final rates.

MERC and the Department disagree on the following item and the Department continues to recommend:

- require MERC to increase Natural Gas Revenue by $3,758,090 for CIP revenue.

ALJ
The ALJ addressed CIP-related issues on pages 82-90, Findings 552-613

Final Rates Compliance Filing
In findings 566, the ALJ recommended that MERC should report in its final rates compliance filing the calculation of the CCRC rate based upon terms of the Commission's Order.

In findings 612, the ALJ recommended that MERC's CCRC calculation is reasonable, contingent upon MERC updating the CCRC in final rates and making a CIP balance adjustment, the CCRC factor should be approved.

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[275] See Department Ex. 219, St. Pierre Surrebuttal at p. 16

Under-Collected CIP revenues and expenses during the Interim Rate Period caused by updating the CCRC factor at final rates compliance filing

In findings 565, the ALJ recommended to the Commission that MERC's proposal to credit the CIP tracker balance, in the event that it under-collects CIP expense during interim rate period, is reasonable.

The Department's "Revenue Neutral" adjustment of $3,758,090
In findings 580 and 581, the ALJ recommended that balancing test-year CIP revenue with test-year CIP expenses, and reflecting the appropriate charges as part of the final approved CIP rate, will increase transparency in ratemaking and potentially reduce future audit costs and rate case expenses and further recommended setting the CIP revenue equal to the CIP expense so that final rates include CIP revenue and CIP costs of $9,396,422.

In findings 582, the ALJ recommended that the CCRC should be added to the CCRA on January 1, 2015, or with implementation of final rates, whichever occurs later.

In findings 613, the ALJ summarized his recommendations on the "revenue neutral" issue:

- MERC should report in its final rates compliance filing the calculation of the CCRC rate based upon the Commission's Order, with respect to the level of CIP expenses divided by the level of sales approved by the Commission;
- CIP would be recovered through one line item on a customer's bill (MERC CCRA); and
- in future general rate-case filings, MERC should change the CCRC rate at the beginning of interim rates and again at final rates.

Exceptions

MERC
MERC requested clarification on the following ALJ recommendations:

> 580. The Administrative Law Judge finds that balancing test-year CIP revenue with test-year CIP expenses, and reflecting the appropriate charges as part of-the final approved CIP rate, will increase transparency in ratemaking and potentially reduce future audit costs and rate case expenses.
>
> 581. The Administrative Law Judge recommends setting the CIP revenue equal to the CIP expense so that final rates include CIP revenue and CIP costs of $9,396,422.
>
> 582. Additionally, the Administrative Law Judge recommends that the CCRC should be added to the CCRA on January 1, 2015, or with implementation of final rates, whichever occurs later.

MERC requested that the Commission clarify these findings to make clear that MERC's CCRC be set to $0.00000 and as of January 1, 2015, or the implementation of final rates, whichever is later, and that the calculated CCRC in this case will be added to the CCRA tracker mechanism and charged to customers. Specifically, MERC requested that the CCRC factor be added to the final CCRA factor to be approved in Docket No. G011/M-14-369. For simplicity, the consolidated factor should be renamed to avoid customer confusion and should be implemented at the same time as MERC's pending consolidated CCRA in Docket No. G011/M-14-369. Additionally, MERC requested clarification that, under the proposed treatment of CIP expense, MERC will increase the CIP tracker balance by the amount of CIP expense recognized for the time interim rates were in effect, and reverse out the CIP expense recognized during that time. Currently, MERC is collecting revenue from customers and crediting the CIP tracker balance at MERC's filed CCRC factor of $0.02432.

MERC requests the following clarifications to Proposed Findings 580 through 582 and the addition of further findings related to treatment of CIP expense as follows:

> 580. The Administrative Law Judge finds that balancing test-year CIP revenue with test-year CIP expenses <u>by removing CIP expense and revenue from the Income Statement</u>, ~~and reflecting the approximate charges as part of the final approved CIP rate,~~ will increase transparency in ratemaking and potentially reduce future audit costs and rate case expenses.
>
> 581. The Administrative Law Judge recommends ~~setting~~ <u>removing</u> the CIP revenue ~~equal to the~~ <u>and</u> CIP expense <u>from the Income Statement</u> ~~so that final rates include CIP revenue and CIP costs of $9,396,422~~
>
> 582. Additionally, the Administrative Law Judge recommends that the CCRC <u>be removed from MERC's Distribution Rates and</u> ~~should~~ be added to the CCRA on January 1, 2015, or with implementation of final rates, whichever occurs later.
>
> #. <u>Because MERC's CCRC will be set to $0.0000, MERC will have over-recorded CIP expense during the time that the Company's interim rates were in effect.</u>
>
> #. <u>The Administrative Law Judge recommends that MERC debit the CIP tracker balance to offset for over-collection of CIP expense during the interim rate period and credit the CIP Amortization account for the same amount.</u>

MERC generally agreed with the ALJ's factual recounting of the calculation of the CCRC (Findings 597-611) and agreed with the ALJ's recommendation that MERC's CCRC is reasonably contingent on MERC updating the CCRC in final rates and making a CIP tracker balance adjustment (Finding 612). Regarding changing the CCRC rate at the beginning of interim rates and again at final rates, MERC notes that this applies only if the CCRC is not removed from base rates. Thus, MERC requested the following clarification to ALJ Finding 613:

> 613. The Administrative Law Judge recommends that:
>
> (1) MERC should report in its final rates compliance filing the calculation of the CCRC rate based upon the Commission's Order, with respect to

the level of CIP expenses divided by the level of sales approved by the Commission;

(2) CIP would be recovered through one line item on a customer's bill (MERC CCRA); and

(3) in future general rate-case filings, <u>if the CCRC is not removed from rate base,</u> MERC should change the CCRC rate at the beginning of interim rates and again at final rates.

Department

The Department seeks clarification on the ALJ Report that makes an erroneous recommendation regarding CCRC at paragraph 613 that should be corrected as follows:

613. The Administrative Law Judge recommends that:

(1) MERC should report in its final rates compliance filing the calculation of the CCRC rate based upon the Commission's Order, with respect to the level of CIP expenses divided by the level of sales approved by the Commission;

(2) CIP would be recovered through one line item on a customer's bill (MERC CCRA); and

(3) <u>If the Commission decides to keep the CCRC in the Distribution rate, then</u> in future general rate-case filings, MERC should change the CCRC rate at the beginning of interim rates and again at final rates.

PUC Staff Comment

Revenue Deficiency Calculation Methodology in Rate Cases

In MERC last rate case,[276] PUC staff believed that the test year CIP expense should be assigned to the interim CCRC rate[277] and that the increased CCRC revenues should be put into the CIP tracker account.[278] In its final compliance filing, MERC stated that for purposes of calculating the interim refund, the increase in CIP expenses was removed from the final ordered increase.[279] MERC assigned or calculated the CIP revenues generated from the increased interim CCRC factor and made a delayed lump sum credit to the CIP tracker. While this imputation of revenue had the effect of balancing (or creating revenue neutrality within) the interim rates, the practice resulted in confusion for those who were reviewing the Company's rate-related filings.

Prior to this rate case, MERC sought advice from the PUC staff as to the best way to reflect increases in CCRC in interim rates. Commission staff advised MERC to reflect increase

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[276] Docket No. 10-977

[277] Or alternatively, calculate the CIP revenues during the interim rate period generated from the increased interim CCRC factor

[278] See Docket No. 10-977, Staff Briefing Paper for May 22 and 24, 2012 Agenda Meetings at 183

[279] Docket No. 10-977 Compliance Filing, September 21, 2012 at Section entitled "Refund Plan," first page.

expenses in the interim rate calculation.[280] For its revenue deficiency calculation, MERC used the Docket No. 10-977 CCRC factor of $0.01513 and projected sales forecast to calculate its CIP revenue while using the test year CIP expense level of $8,920,481 (initially) and later $9,396,422 (parties agree upon level). MERC's methodology calculated annual CIP revenues of $5,548,880[281] compared to its as filed test year CIP expenses of $8,920,481 the result adds $3,371,601 to the revenue deficiency reflected by MERC.

On July 24, 2013, PUC staff responded to MERC request regarding the method of handling CCRC revenue and expense.[282] PUC staff stated:

> In the nest rate case, **instead of imputing a revenue amount to offset the increase in CIP expenses, you should include the full amount of the test-year CIP expense in the interim rate revenue deficiency and start collecting that with interim rates.** The CCRC in the CIP tracker will get recalculated at the end of the case going back to the start of interim rates. CIP expenses are usually considered of the same nature and kind from one year to the next. That's the way most of the other companies handle increases in test-year CIP expenses. [Emphasis added]

PUC staff believes that MERC followed its interpretation of PUC staff's sentence, in that MERC placed its initial petition's CIP expense in the revenue deficiency and started collecting the revised CCRC factor in revenues and crediting that amount in the CIP tracker. However, MERC did not include the revised CCRC factor and associated revenues in its revenue deficiency calculation. PUC staff interpretation was that MERC should start collecting the revised CCRC factor, but PUC staff's assumption was that the CIP revenue would carry-over to MERC's revenue deficiency. By using PUC staff interpretation of how the CIP method should work, MERC's revenue deficiency would be "revenue neutral" for CIP revenues and expenses. In other words, the CIP revenue and expense should not have an impact on MERC's revenue deficiency analysis.

The Department recommended that MERC add $3,758,090 to its revenue in its deficiency calculation to make MERC "revenue neutral" for CIP revenues and expenses. The CIP revenue increase takes into account the Department's adjustments to MERC's CCRC factor calculation, the increase in test year CIP expense and its sales forecast.

PUC staff believes that MERC is already collecting the CCRC revenue and that amount is being funded in MERC's CIP account, thus MERC should not be reflecting a revenue deficiency amount associated to CIP. PUC staff believes that MERC's CIP method in its revenue deficiency is overstating its overall rate case deficiency and that by accepting MERC's methodology would lead to double-collecting the CIP revenue shortfall. As discussed in its Direct testimony, PUC staff believes that the Department's adjustment to CIP revenues is appropriate. MERC's revenue deficiency analysis should reflect the same CIP revenues and expenses; therefore, CIP does not impact MERC's deficiency analysis.

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[280] See PUC staff Ex. 250
[281] MERC's CCRC applicable volumes of 366,746,833 times its 10-977 CCRC factor of $0.01513, for volume detail, see MERC Ex. 19, DeMerritt Direct at Exhibit SSD-24
[282] See PUC staff Ex. 250

PUC staff agrees with the ALJ's recommendations in findings 580 and 581, that balancing test-year CIP revenue with test-year CIP expenses, and reflecting the appropriate charges as part of the final approved CIP rate, will increase transparency in ratemaking and potentially reduce future audit costs and rate case expenses and further recommended setting the CIP revenue equal to the CIP expense so that final rates include CIP revenue and CIP costs of $9,396,422.

In order to prevent further confusion in subsequent rate cases, PUC staff recommends to the Commission that it require MERC to meet with the Department and PUC staff before filing its rate cases in the future. PUC staff suggests a meeting similar to how the Commission's required pre-filing meeting on sales forecast is structured.

Test Year CIP Expenses

MERC filed for a test year CIP expense level of $8,920,481 which represented the 2013 CIP Triennial Report level which has received the approval from the Department of Commerce. The Department's review recommended that the test year CIP expense level should $9,396,422 which is the 2014 CIP Triennial level. MERC has agreed to that CIP expense level.

CIP Expense Summary

	MERC-As Filed	Department-Direct	PUC staff Recommendation
CCRC Expense Level	$8,920,481	$9,396,422	$9,396,422

PUC staff believes that for a 2014 test year, the CIP expense level should be the 2014 CIP Triennial Report expense level of $9,396,422 and recommends to the Commission that it approve that CIP expense level to be reflect in MERC's final rates compliance filing.

As previously indicated, this issue is uncontested, all parties are in agreement.

Test Year Sales Forecast

In its as filed CCRC factor calculation, MERC used CCRC applicable sales volumes of 366,746,833 therms. In the Department Direct testimony, it adjusted the sales forecast by 26,791,936 therms, MERC has agreed to this adjustment. Of the 26,791,936 sales forecast adjustment increase, 17,079,366 therms is associated with the sales forecasted CCRC applicable volumes.

In MERC Rebuttal testimony, its revised CCRC factor calculation erroneously excluded the sales forecast volumes associated the SVI-NNG transport customers in the amount of 2,104,347 therms, as reflected in the below table. The omission does impact MERC's revised CCRC factor calculation, discussed further below.

PUC staff believes that MERC's error should be corrected when it files its final rates compliance filing in this docket.

Sales Forecast Summary for CCRC factor calculation

In Therms	MERC-As Filed	Department-Direct	MERC-Revised	PUC staff Recommendation
MN Sales Forecast	662,833,577	689,625,513	687,521,166	689,625,513
CIP Exempt Volumes	296,086,744	305,799,314	305,799,314	305,799,314
CCRC Applicable	366,746,833	383,826,199	381,721,852	383,826,199

As previously discussed above, this issue is uncontested; all parties are in agreement, except for MERC's Rebuttal testimony error.

Interim Rate Period CCRC Factor

In Docket No. 10-977, MERC's approved CCRC factor was $0.01513/therm, this resulted in an increase $0.00919/therm or a 60.74% increase over MERC's initial petition's CCRC factor calculation of $0.02432.

The primary driver for the CCRC factor increase is the number of MERC customers who have become CIP exempt since the last rate case. For comparison purposes, see the following chart which illustrates this phenomena:

Description	10-977[283]	13-617[284]	Difference	% Change
Sales volume	683,768,889	662,833,577	- 20,935,312	-3.06%
Less: CIP Opt-out volumes	125,111,337	296,086,744	170,975,407	136.66%
CCRC applicable Volumes	558,657,552	366,746,833	-191,910,719	-34.35%

As reflected in the below table, MERC's initial petition CCRC factor was $0.02432 based on its CIP test year cost and its applicable CIP volumes. In its Direct testimony, the Department subsequently adjusted the test year CIP expense from 2013 to 2014 Triennial Report CIP expense level and further adjusted MERC's initial petition's sales forecast, as discussed above. MERC agreed to both of these adjustments and its Rebuttal testimony provided a revised CCRC factor calculation of $0.02462 based on its assumption reflected in the below calculation.

Interim period CCRC factor calculation summary:

	MERC Direct	MERC Rebuttal	PUC Staff Recommended
CCRC Expense	$8,920,481	$9,396,422	$9,396,422
CIP Volume	366,746,833	381,721,852	383,826,199

[283] See MERC Docket No. G-007,011/GR-10-977, Compliance Filing date April 12, 2012, Attachment E.
[284] See Seth DeMerritt Direct Testimony, Exhibit SSD-24.

CCRC Rate	$0.02432	$0.02462	$0.02448

In findings 612, the ALJ recommended that MERC's CCRC calculation was reasonable, contingent upon MERC updating the CCRC in final rates and making a CIP balance adjustment, the CCRC factor should be approved. PUC staff believes that the CCRC calculation method is reasonable, PUC staff respectfully disagrees with MERC's interim rate period CCRC factor of $0.02462 is reasonable. PUC staff believes that MERC's revised CCRC factor calculation is incorrect because of its mistake in calculating its adjusted sales forecast as discussed in the above discussion. The PUC staff's revised calculation derives a CCRC factor of $0.02448 as reflected in the above table.

PUC staff recommends to the Commission that it approves PUC staff revised calculation for the interim rate period and require MERC to make the necessary corrections in its final rates compliance filing. Therefore, PUC staff agrees with ALJ findings 566 and 613 that MERC should report in its final rates compliance filing the calculation of the CCRC rate based upon terms of the Commission's Order.

In findings 613, the ALJ recommended that in future general rate-case filings, MERC should change the CCRC rate at the beginning of interim rates and again at final rates.

Over/Under Collected Interim Period CIP Revenues

Over/Under-Collected CIP revenues and expenses occur during the Interim Rate Period are caused by updating the CCRC factor at final rates compliance filing.

As previously stated, MERC is collecting its interim rate period CCRC factor of $0.02432 and is funding its CIP tracker with those revenues. If the CCRC factor is changed from $0.02432 during the interim period, MERC's CIP tracker could be either over/under collected and would require an adjustment if the ALJ recommended CCRC factor of $0.02462 or PUC recommended CCRC factor of $0.02448 is adopted by the Commission.

MERC addressed that by accepting the Department's test year cost adjustment and the Department's adjusted sales forecast by stating:

> …..a slight adjustment will need to be made at the time of final rates. Currently, in interim rates, MERC is collecting revenue from customers and crediting the CIP tracker balance at MERC's filed CCRC of $0.02432. Rebuttal Exhibit_____(SSD-2) shows the CIP tracker balance as of February 28, 2014, based on the interim CCRC factor of $0.02432. If MERC's CCRC of $0.02462, as recommended in MERC's rebuttal testimony, is approved in this proceeding, MERC will have under-collected CIP expense during the time frame that the Company's interim rates were in effect. In the event that a CCRC of $0.02462 is approved and MERC has under-collected CIP expense, MERC would recommend crediting the CIP tracker balance (Account No. 182705) by $0.00030 ($0.02462 - $0.02432) x actual sales during the period interim rates were in effect, and debiting the CIP Amortization account (Account No. 407710) for this same amount. This adjustment would increase MERC's CIP expenses that should have been recognized

during interim rates, which would be offset by a lower refund to customers because of the 4 higher revenue requirement generated by the increased CIP expenses.

MERC proposed accounting entities are:

	Debit	Credit
407710 CIP Amortization Expense	$114,517	
182705 CIP Costs-Current Year		$114,517

(Note: $114,617 = $0.00030 ($0.02462 - $0.02432) times 381,721,852 therms)

As previously discussed, the Department stated that MERC suggested method of handling the potential over/under collection as reasonable.

In findings 565, the ALJ recommended to the Commission that MERC's proposal to credit the CIP tracker balance, in the event that it under-collects CIP expense during interim rate period, is reasonable.

PUC staff agrees with the ALJ's recommendation, but would like to add "to debit the CIP balance, in the event that it over-collects the CIP expense during the interim period, is reasonable."

Presentation of CCRC and CCRA in the future

In its rebuttal testimony, MERC stated that based on discussions between the Department and itself following the submission of the Department's Direct Testimony, it was MERC's understanding that the Department's ultimate goal was to remove the CCRC from base rates completely, thereby allowing all CIP expenses to flow through the CCRA in the CIP tracker account. The Department proposed that MERC remove all CIP expenses from the revenue deficiency. MERC would then seek recovery for any over/under-collection of CIP expenses through a separate docket filed annually.

MERC stated that it would not be opposed to this approach provided that the dockets related to the CCRA are finalized and an order is issued in a timely fashion. In addition, if changing the CCRC in the distribution rate to $0.00000 were to occur in the this docket, MERC would request that its currently recommended CCRC of $0.02462 be added to the CCRA factor on January 1, 2015, or with implementation of final rates, whichever occurs later, so as not to delay the recovery of these expenses.

In response to MERC's statement, in the Department's Surrebuttal testimony, the Department stated that this ***was not*** its intention, but to merely set CIP revenues equal to the CIP expenses. The Department's reason for not recommending this method at this time was because it is easier to understand and accept if the CCRC is determined similar to the way that the base cost of gas is determined.

In findings 582, the ALJ recommended that the CCRC should be added to the CCRA on January 1, 2015, or with implementation of final rates, whichever occurs later, and

In findings 613, the ALJ recommended that CIP would be recovered through one line item on a customer's bill (MERC CCRA).

PUC staff believes that the ALJ's recommendations could be interpreted in different ways. It is not clear to PUC staff how the ALJ wanted MERC to proceed in the future in regard to CIP revenues and expenses. PUC staff believes that the ALJ recommendations could be interpreted as follows:

A. MERC could remove the CCRC factor from its base distribution rate along with the CIP expenses and account for the entire program through its CIP tracker account. This would combine the CCRC and CCRA into one CIP charge that would be adjusted through MERC's CIP annual tracker mechanism, in accordance with current tariff provisions. **or**

B. MERC could calculate its CCRC factor as it currently does, but instead of including the CCRC charge in its base distribution rate, MERC could combine its CCRC base factor and the current CCRA factor into one line item on its customer's bills. **or**

C. MERC could calculate its CCRC factor as it currently does, but instead of including the CCRC charge in its base distribution rate, MERC could separately state its CCRC base factor and the current CCRA factor on separate lines on its customer's bills.

PUC staff does not have a preferred methodology, but whatever the Commission decides, PUC staff would like the calculation to be transparent and easy for MERC's customers and all other parties to understand.

Decision Alternatives - Impact on Revenue Deficiency (Are CIP revenues and expenses "revenue neutral"?

Revenue Deficiency Calculation Methodology in Rate Cases

1. Adopt the ALJ's recommendations in findings 580 and 581 that require MERC to balance test-year CIP revenue with test-year CIP expenses, and reflect the appropriate charges as part of the final approved CIP rate by setting the CIP revenue equal to the CIP expense so that final rates include CIP revenue and CIP costs of $9,396,422. The ALJ states that will increase transparency in ratemaking and potentially reduce future audit costs and rate case expenses and further.

2. Adopt PUC staff's recommendation that would require MERC to have a pre-meeting with the Department and PUC staff before filing subsequent rate cases. (structured similar to the required pre-filing meeting on sales forecast)

Interim Rate Period CCRC Factor

3. Adopt the ALJ's recommendation that MERC CCRC calculation methodology is reasonable, but adopt PUC staff's recommendation to require MERC to update its CCRC factor to reflect the Department recommended 2014 CIP expenses of

$9,396,422 and to correct its CIP applicable volumes to the Department recommended level in its final rates compliance.

4. Adopt the ALJ recommendation that would require MERC to report in its final rates compliance filing the calculation of the CCRC rate based upon terms of the Commission's Order.

5. Adopt the ALJ recommendation that in future general rate-case filings, MERC should change the CCRC rate at the beginning of interim rates and again at final rates.

Over/Under Collected Interim Period CIP Revenues

6. Adopt the ALJ recommendation to the Commission that MERC's proposal to credit the CIP tracker balance, in the event that it under-collects CIP expense during interim rate period, is reasonable

7. Adopt the ALJ recommendation and in addition adopt PUC staff recommendation to add "to debit the CIP balance, in the event that it over-collects the CIP expense during the interim period, is reasonable."

Presentation of CCRC and CCRA in the future

8. Adopt the ALJ recommendation assuming that MERC removes its CCRC factor from its base distribution rate along with the CIP expenses and account for the entire program through its CIP tracker account. Require MERC to combine the CCRC and CCRA into one CIP charge that would be adjusted through MERC's annual CIP tracker mechanism, in accordance with current tariff provisions.

9. Adopt the ALJ recommendation assuming that MERC calculates its CCRC factor as it currently does, but instead of including the CCRC charge in its base distribution rate, require MERC to combine its CCRC base factor and the current CCRA factor into one line item on its customer's bills.

10. Adopt the ALJ recommendation assuming that MERC calculates its CCRC factor as it currently does, but instead of including the CCRC charge in its base distribution rate, require MERC to separately state its CCRC base factor and the current CCRA factor on separate lines on its customer's bills.

11. Require no change to MERC's current handling of its CIP revenues and expenses. Require MERC to continue its current CCRC calculation methodology by including the CCRC factor in its base distribution rate and maintain its CCRA factor in its current format.

(Note: These decision alternatives corresponds to alternatives 90 through 100 on the deliberation outline.)

Reference to Record
MERC Docket No. 10-977, Compliance Filing dated April 12, 2012, Attachment E
MERC Triennial CIP Report
MERC Ex. 19 DeMerritt Direct at pp. 41-44 and Ex. SSD-24
MERC Ex. 21 DeMerritt Supplemental Direct at pp. 3-5 and Exhibits SSD-1, SSD-2, and SSD-3
MERC Ex. 24, DeMerritt Rebuttal at pp. 5-7, 13, Schedule SSD-1, and Schedule SSD-2
MERC Ex. 39, John Rebuttal at p. 13
MERC Ex. 40 Walters Direct, GJW-1, Schedule 3 Summary, p.1 and Schedule 5 Summary, p.1
Department Ex. 217, St. Pierre Direct at pp. 13-17 and Exhibit MAS-16
Department Ex. 219, St. Pierre Surrebuttal at pp. 11-19 and MAS-S-16
Department Ex. 212 Otis Direct at pp. 27-32 and LBO-12 at pp. 1-2
Evidentiary Hearing Transcript at 23 (DeMerritt) (May 13, 2014)
Docket No. 10-977, Staff Briefing Paper for May 22 and 24, 2012 Agenda Meetings at 183
Docket No. 10-977 Compliance Filing, September 21, 2012 at Section entitled "Refund Plan," first page.
PUC staff, Ex. 250
ALJ Report, pp. 82-90, findings 552-613

Cost of Gas

Base Cost of Gas

PUC Staff: Bob Brill

Introduction

With every rate case petition a utility company must accompany its petition with a miscellaneous rate change petition to adjust its base cost of gas; demand and commodity base cost of gas rates. The base cost of gas is further adjusted monthly through MERC's Purchased Gas Adjustment (PGA) for any differences between the base cost of gas and current gas costs.

MERC's natural gas system is designed having two PGA systems, MERC-NNG and MERC-Consolidated. This PGA structure was requested by MERC and approved by the Commission in Docket No. G007,011/GR-10-977. Previous to the 10-977 docket, MERC operated its system with a 4 PGA structure.

Background

Minnesota Rules 7825.2700, subpart 2 requires:

> A new base gas cost must be submitted as a miscellaneous rate change to coincide with the implementation of interim rates during a general rate proceeding. A new base gas cost must also be part of the rate design compliance filing submitted as a result of a general rate proceeding. The base gas cost must separately state the commodity base cost and the demand base cost components for each class. The base gas cost for each class is determined by dividing the estimated base period

> cost of purchased gas for each class by the estimated base period annual sales volume for each class.

MERC filed its Docket No. 13-617 rate case on September 30, 2013. On the same day, MERC filed its base cost of gas petition in Docket No. G011/MR-13-732[285] and the Department concluded that MERC's base cost of gas petition was compliant with the requirements of Minn. Rules 7825.2700, Subp. 2.

The Commission's November 27, 2014 ORDER SETTING NEW BASE COST OF GAS, Docket No. G011/MR-13-732, approved MERC's new base cost of gas in the amount of $173,411,039, and required MERC to provide updated commodity cost of gas information at least once during the contested rate case proceeding, to be filed both in the base cost of gas docket and the general rate case docket.

In the rate case proceeding, the Commission's November 27 Order[286] required MERC to provide the following information:

> 2. The potential impact of updated sales forecasts and commodity pricing forecast updates on the demand and commodity cost of gas rates. MERC shall provide updated sales forecasts and commodity pricing forecasts from its general rate case and information on the potential impact of these updates on its per-dekatherm demand and/or commodity cost of gas rates. These updates should be filed in this docket and the related base cost of gas matter, in Docket No. G-011/MR-13-732.

Base Cost of Gas Summary

MERC's initial 13-732 petition proposed new base cost of gas rates for each of its PGA systems. The total monthly costs for 2014 are added together to calculate the total annual gas cost for each PGA system and are divided by the projected annual sales forecast for the respective PGA system in order to separately develop the demand and commodity base cost of gas rate components. The initial petition's commodity costs assumption was based on the May 15, 2013 NYMEX pricing. The demand and commodity costs and rates are summarized in Tables 1-6, Col. 2.

On April 15, 2014, MERC filed its updated Base Cost of Gas petition in Docket No. 13-732. The petition was updated for March 27, 2014 NYMEX commodity pricing forecasts. The commodity costs were updated, but the demand costs and sales forecast did not change from the initial Docket No. 13-732 petition. The updated commodity costs increased by $30,498,186 over the initial petition, as reflected in Table 5, Col. 3 minus Col. 2.

The Department commented that MERC's NYMEX pricing and calculations were reasonable. However, the Department adjusted MERC's sales forecast[287] by 26,791,937 therms and MERC

[285] A miscellaneous rate proceeding
[286] Commission Order dated on November 27, 2013 in Docket No. 13-617- NOTICE AND ORDER FOR HEARING
[287] See Department Ex. 212, Otis Direct at pp. 28-32

later agreed to and accepted the adjustment.[288] Since MERC's April 15 petition did not update the sales forecast to the agreed upon level, the Department requested that MERC provide an updated base cost of gas calculation reflecting the March 27, 2014 NYMEX pricing and the agreed upon adjusted sales forecast.[289] After receiving the updated base cost of gas calculation, the Department concluded the calculations to be reasonable.[290]

The Department commented that MERC's approach was similar to other utility companies and recommended that the Commission approve MERC's final rates based on the revised April 15th commodity gas pricing and the updated test year sales forecast.[291]

Base Cost of Gas <u>Rates</u> Summary

Table 1: General Service Total Base Cost of Gas Rates

PGA System	Initial Petition $/therm[292] [293]	April 15, 2014 Update $/therm[294]	Adjusted for Sales Forecast $/therm[295]
MERC – NNG	0.63590	$0.73062	$0.73839
MERC - Consolidated	0.53083	$0.68510	$0.69489

Table 2: Commodity Base Cost of Gas Rates applicable to all customers

PGA System	Initial Petition $/therm[296]	April 15, 2014 Update $/therm[297]	Adjusted for Sales Forecast $/therm[298]
MERC – NNG	0.45635	$0.55107	$0.56271
MERC – Consolidated	0.44825	$0.60252	$0.61412

[Staff Note: MERC did not update the underlying volumes in its April 15, 2014 petition from the initial petition in Docket No. 13-732]

288 See MERC Ex. 37, John Rebuttal at p. 13
289 See Department 214, Otis Surrebuttal at pp. 9-14 and Ex. LBO-S-4
290 Id.
291 See Department Ex.214, Otis Surrebuttal at pp. 9-10 and Evidentiary Hearing Transcript, Otis at pp. 208-209
292 Includes both demand and commodity costs and volumes, demand costs and volumes remain un-changed throughout the docket
293 See Docket No. 13-732, Initial Petition, Ex. MJA, Exhibit No. 1, pp. 22-23
294 See Docket No. 13-732, April 15, 2014 Updated Petition, Ex. MJA, Exhibit No. 2, pp. 22-23
295 See Department Ex. 214, Otis Surrbuttal at pp. 9-13 and Ex. LBO-S-4, pp. 22-23
296 See Docket No. 13-732, Initial Petition, Ex. MJA, Exhibit No. 1, pp. 22-23
297 See Docket No. 13-732, April 15, 2014 Updated Petition, Ex. MJA, Exhibit No. 2, pp. 22-23
298 See Department Ex. 214, Otis Surrbuttal at pp. 9-13 and Ex. LBO-S-4, pp. 22-23

Table 3: General Service Demand Base Cost of Gas Rates

PGA System	Initial Petition $/therm[299]	April 15, 2014 Update $/therm[300]	Adjusted for Sales Forecast $/therm[301]
MERC – NNG	$0.17955	$0.17955	$0.17568
MERC – Consolidated	$0.08258	$0.08258	$0.08077

Base Cost of Gas Summary

Table 4: Total Gas Costs

	Initial Petition[302]	April 15,2014 Updated Petition[303]	Adjusted for Sales Forecast[304]
Twelve Months Ended 12/31/14 – NNG	$145,592,129	$167,798,558	$176,953,679
Twelve Months Ended 12/31/14 – Consolidated	$27,818,910	$36,110,667	$37,904,883
Total Costs	$173,417,039	$203,909,225[305]	$214,858,562[306]

Table 5: Commodity Costs

	Initial Petition[307]	April 15,2014 Updated Petition[308]	Adjusted for Sales Forecast[309]
Twelve Months Ended 12/31/14 – NNG	$106,986,753	$129,193,182	$138,348,086
Twelve Months Ended 12/31/14 - Consolidated	$24,092,899	$32,384,656	$34,178,710
Total Commodity Costs	$131,079,652	$161,577,838	$172,526,796

299 See Docket No. 13-732, Initial Petition, Ex. MJA, Exhibit No. 1, pp. 22-23
300 See Docket No. 13-732, April 15, 2014 Updated Petition, Ex. MJA, Exhibit No. 2, pp. 22-23
301 See Department Ex. 214, Otis Surrbuttal at pp. 9-13 and Ex. LBO-S-4, pp. 22-23
302 See Docket No. 13-732, Initial Petition, Ex. MJA, Exhibit No. 1, pp. 11-23
303 See Docket No. 13-732, April 15, 2014 Updated Petition, Ex. MJA, Exhibit No. 2, pp. 11-23
304 See Department Ex. 214, Otis Surrbuttal at pp. 9-13 and Ex. LBO-S-4, pp. 11-23
305 PUC staff notes that when the cost of gas rates developed in this petition were applied to the agreed upon forecast in MERC Ex. 42, Walters Rebuttal it results in a $212,285,349 gas cost instead of $203,909,225 as reflected in Table 4. The April 15 Petition did not include the agreed upon sales forecast in its calculations
306 PUC staff notes that when the rates developed in these schedules are applied to the agreed upon sales forecast it results in a $214,858,858 gas cost as reflected in the Department Ex. 214, Otis Surrebuttal, Ex. LBO-S-4 and LBO-S-6. The $296 ($214,858,858 minus $214,858,562) difference is attributed to rounding. Further, the Department's Operating Income Summary (as filed with the Department's post hearing reply brief) reflects purchased gas costs of $221,858,262, whereas the surrebuttal testimony of Department witness Laura Otis suggests that purchased gas costs should be $214,858,858.
307 See Docket No. 13-732, Initial Petition, Ex. MJA, Exhibit No. 1, pp. 11-23
308 See Docket No. 13-732, April 15, 2014 Updated Petition, Ex. MJA, Exhibit No. 2, pp. 11-23
309 See Department Ex. 214, Otis Surrbuttal at pp. 9-13 and Ex. LBO-S-4, pp. 11-23

Table 6: Demand Costs

	Initial Petition[310]	April 15, 2014 Updated Petition[311]	Adjusted for Sales Forecast[312]
Twelve Months Ended 12/31/14 – NNG	$38,605,376	$38,605,376	$38,605,593
Twelve Months Ended 12/31/14 - Consolidated	$3,726,011	$3,726,011	$3,726,173
Total Base Cost of Gas	$42,331,387	$42,331,387	$42,331,766

[Staff Note: MERC recovers Company Use costs as part of its normal Operation and Maintenance Expenses in base distribution rates; therefore, these costs are not included in the above amounts. Company Use gas costs are not recovered in the base cost of gas or in the monthly Purchased Gas Adjustment (PGA) petitions.]

ALJ

In proposed finding 202, the ALJ recommended that the Commission approve a base cost of gas amount based on the updated April 15th commodity gas pricing and the Department's updated test year sales figure. This increases MERC's original gas costs estimate of $173,412,059 to $214,858,562, an increase of $41,446,503.[313] [See Table 4]

PUC Comment

PUC staff does not necessarily disagree with the Department and the ALJ recommendations, but offers the following discussion. In its April 15, 2014 base cost of gas update filing, MERC updated its commodity cost of gas to reflect March 27, 2014 NYMEX pricing. The March 27th NYMEX pricing included the effects of the TransCanada incident that impacted the price of natural gas during the 2013-2014 heating season, see Table 7.

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310 See Docket No. 13-732, Initial Petition, Ex. MJA, Exhibit No. 1, pp. 5 and 19-23
311 See Docket No. 13-732, April 15, 2014 Updated Petition, Ex. MJA, Exhibit No. 2, pp. 5 and 19-23
312 See Department Ex. 214, Otis Surrbuttal at pp. 9-13 and Ex. LBO-S-4, pp. 5 and 19-23
313 See ALJ Report at p. 32, proposed finding 201.

Table 7: Comparison of NYMEX pricing

Receipt Point	Initial Petition[314]	April 15,2014 Updated Petition[315]	Adjusted for Sales Forecast[316]
Ventura Feb. 2014	$4.5070	$7.67	$7.67
Ventura Mar. 2014	$4.4280	$10.49	$10.49
Emerson Feb. 2014	$4.5660	$7.6570	$7.6570
Emerson Mar. 2014	$4.5190	$11.1425	$11.1425

All test year months in the March 27th NYMEX update did change from the initial base gas petition, but the months of February and March 2014 reflected sufficient increases caused by the TransCanada incident. In the other test period months the base gas pricing did not vary dramatically from the initial petition.

As illustrated by Table 7, the March 27th price of gas increased during February and March 2014 by approximately $3/Dth to $6/Dth. The Ventura price increased in March from $4.4280/Dth to a price of over $10.49/Dth and at Emerson the price increased from $4.5190 to $11.1425.[317] In the April 15th update, the cost of gas increased by $30,492,186; see Table 4, Col. 3 minus Col. 2. The gas cost increase in February and March caused the majority of the gas cost increase.

The Department Ex. 214, Otis Surrebuttal Ex. SBO-S-4 reflects the March 27th NYMEX price update included in the April 15th update and the agreed upon sales forecast, which increased the gas cost by $41,446,503, see Table 4, Col. 4 minus Col. 2.

Since the filing of March 27th NYMEX pricing, the price of gas has continued the decline back to previous price level of between $3.75 and $4.50 before the TransCanada incident and all evidence points to the conclusion that the price will remain under $5/Dth during the 2014-2015 heating season.

PUC staff believes that the Commission may wish to require MERC to provide an updated base cost of gas petition reflecting the future pricing for February and March 2015, instead of the extraordinary TransCanada gas pricing circumstances. PUC staff believes that the future pricing method will remove the effects caused by the extraordinary incidents during the 2013-2014 heating season; thus reducing the overall gas costs. The extraordinary gas costs have already been recovered through MERC's monthly PGA calculation. By requiring the update, PUC staff believes the calculation will produce a base gas cost more in-line with the gas prices going forward.

[Staff Note: A change in the base gas calculation may also impact the Uncollectible calculation, Cash Working Capital, Storage Gas Balance, and Interest Synchronization.]

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[314] See Docket No. 13-732, Initial Petition, Ex. MJA, Exhibit No. 1, p. 12
[315] See Docket No. 13-732, April 15, 2014 Updated Petition, Ex. MJA, Exhibit No. 2, p. 12
[316] See Department Ex. 214, Otis Surrbuttal at Ex. LBO-S-4, p. 12
[317] See Docket No. 13-732, Initial Petition, Ex. MJA, Exhibit No. 1, p. 12 and See Docket No. 13-732, April 15, 2014 Updated Petition, Ex. MJA, Exhibit No. 2, p. 12

Decision Alternatives:

1. Adopt the Administrative Law Judge and the Department recommendations to accept MERC's most recent base cost of gas calculation as reflected in the Department Ex. 214, Otis Surrebuttal at Ex. LBO-S-4, pp. 1-24.

2. Require MERC to provide in a compliance petition in this docket and the base cost of gas docket, an update to the base gas cost of gas reflecting a more current NYMEX pricing estimate for February and March 2015 at a price closer to future projections. The compliance filing would be due within 30 days from the date of the Commission Order in this docket.

(Note: These decision alternatives correspond to alternatives 101 and 102 on the deliberation outline.)

Reference to Record
MERC Ex. 37, John Rebuttal at p. 13
Docket No. 13-732, Initial Petition, Ex. MJA, Exhibit No. 1, pp. 5 and 11-23
Docket No. 13-732, Initial Petition, Ex. MJA, Exhibit No. 2, pp. 5 and 11-23
Department Ex. 212, Otis Direct at pp. 28-32
Department Ex. 214, Otis Surrebuttal at pp. 9-14 and Ex. LBO-S-4, pp. 1-24
ALJ Report at p. 32, proposed finding 201
Evidentiary Hearing Transcript, Otis at pp. 208-209

Gas Storage Balance

PUC Staff: Bob Brill

This issue is resolved between MERC and the Department. No other party offered testimony on the issue.

Introduction

As part of its gas procurement for a heating season, MERC has purchased storage reservation and capacity contracts from Northern Natural to storage working gas to meet its winter needs. This storage gas is treated as a rate base item for cost of service purposes.

Background

The valuation of the Gas Storage Balance is dependent on the Commission's decision on the Base Cost of Gas. The Commission's decision will impact the gas rates used to calculate the Gas Storage Balance.

MERC

MERC filed its initial petition in this docket pricing its storage gas balances at the May 15, 2013 NYMEX as reflected in MERC's companion base cost of gas petition, Docket No. 13-732.

MERC's initial petition included a proposed test year gas storage inventory of $12,013,242[318] in its rate base.

In Docket Nos. 08-835 and 10-977, MERC agreed to update the NYMEX prices to more recent data in its storage gas balance for the final revenue deficiency. MERC has agreed to update in this docket.[319]

Pursuant to Ordering Paragraph 2 of the Commission's November 27th Order, MERC submitted its update to the commodity cost of gas in Docket Nos. G011/GR-13-617 and G011/MR-13-732, based on March 17, 2014 NYMEX prices, filed April 15, 2014. MERC requested to update its gas storage balances included in rate base. By updating the commodity gas costs, the gas storage balance increased by $853,699 to $12,866,941.[320]

Based on the updated April 15th Base Cost of Gas filing in Docket Nos. G011/MR-13-732 and G011/GR-13-617, MERC proposed that its gas storage balance be set at the 13-month average balance of $12,866,941, which was $853,699 higher than the balance included in its initial filing.

Department

The Department's review resulted in it issuing an Informal Information Request to MERC requesting additional detail on how the gas storage balance was calculated. MERC responded with its updated gas storage balance calculation; equivalent to the 13-month average of the gas storage amounts for the period December 2013 to December 2014 using the March 27th NYMEX pricing. The Department concluded that MERC's gas storage balance calculation methodology was the same as Docket No. 10-977.

The Department agreed with MERC's proposal.[321]

No other party filed testimony on this issue. This issue is uncontested.

ALJ

In Finding Point 368, the ALJ found that MERC's gas storage balance should be $12,866,841 for the 2014 test year.

Staff Comment

PUC staff agrees with the Department and ALJ recommendation, subject to the Commission's decision on the base cost of gas in Docket No. G011/MR-13-732. If the Commission decides to make any change to the gas pricing used in the April 15th Petition, the gas storage balance would require re-calculation.

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[318] For calculation, see Docket No. 13-732, MJA Ex. 1, pp. 12-13
[319] See MERC Ex. 19, DeMerritt Direct at p. 9
[320] For calculation, see Docket No. 13-732, MJA Ex. 2, pp. 12-13 (updated for the March 27th NYMEX pricing) and MERC Ex. 24, DeMerritt Rebuttal at p. 29 and Ex. SSD-4, p. 2

[321] See Department Ex. 216, La Plante Surrebuttal at p. 8 and Department Ex. LL-S-3

Decision Alternatives

1. Adopt the Administrative Law Judge and the Department recommendations to accept MERC's proposed gas storage balance of $12,866,841 for 2014 test year.

2. Adopt another gas storage balance number based on the Commission's base cost of gas decision.

3. Adopt some other gas storage balance number.

(Note: These decision alternatives correspond to alternatives 103, 104 and 105 on the deliberation outline.)

<u>Reference to Record</u>
Docket No. 13-732, MJA Ex. 1, pp. 12-13
Docket No. 13-732, MJA Ex. 2, pp. 12-13 (Updated for the March 27th NYMEX pricing)
MERC Ex. 19, DeMerritt Direct at p. 9
MERC Ex. 24, DeMerritt Rebuttal at p. 29, and SSD-4 at pp. 2-3
Department Ex. 216, La Plante Surrebuttal at pp. 7-8 and Department Ex. LL-S-3

Cost of Capital/Rate of Return

PUC Staff: Clark Kaml

Statement of the Issues

What is the appropriate capital structure for MERC?
What is the appropriate cost of debt for MERC?
What is the appropriate cost of equity for MERC?
What is the appropriate rate of return for MERC?

Background

The ALJ addressed cost of capital issues on pages 12 through 28 of his Report.

MERC addressed these issues on pages 2 through 25 of its Initial Brief, and pages 1through 12 of its Reply Brief.

Department discussion of these issues can be found on pages 11 through 56 of its Initial Brief, pages 2 through 14 of its Reply Briefs, and pages 2 through 14 of its Exceptions to the ALJ Report.

The Office of the Attorney General discussed the cost of capital on pages 20 through 33 of its initial brief, pages 16 through 19 of its Reply Briefs, and pages 19 through 24 of its Exceptions to the ALJ Report.

Three parties sponsored ROE witnesses. The Department witness Dr. Amit recommended a return on equity of 9.29; MERC witness Mr. Moul recommended a cost of equity of 10.75 percent; and OAG witness Dr. Chattopadhyay recommended a cost of equity of 8.62 percent.

The Company and the Department agreed on an appropriate capital structure and cost of debt. No party disagreed with their recommendations.

The parties' and ALJ's recommendations are summarized in the table below:

	Capital Structure	**Cost of Capital Components**							
	Proposed	**MERC**		**DOC**		**OAG**		**ALJ**	
	Ratio	Cost	Weighted Cost	Cost	Weighted Cost	Cost	Weighted Cost	Cost	Weighted Cost
Long-Term Debt	44.64%	5.5606%	2.4822%	5.5606%	2.4822%	5.5606%	2.4822%	5.5606%	2.4822%
Short-Term Debt	5.05%	2.3487%	0.1186%	2.3487%	0.1186%	2.3487%	0.1186%	2.3487%	0.1186%
Equity	50.31%	10.75%	5.4084%	9.29%	4.6737%	8.62%	4.3367%	9.79%	4.9253%
WACC			8.0092%		7.2745%		6.9375%		7.5262%

The OAG did not provide a recommendation on the capital structure or cost of debt. For comparative purposes, staff calculated a WACC using the OAG's proposed cost of equity and the Company's proposed capital structure and cost of debt.

Capital Structure

All other things equal, more equity in a capital structure makes investing a safer decision for an outside investor. A greater proportion of equity reduces the possibility that there will not be enough earnings to pay interest on the (reduced amount of) debt and, additionally, it increases the probability that sufficient earnings remain to pay dividends on the equity. Where the proportion of debt is small, lenders will also have reduced concerns about recovering their investment in the event of bankruptcy.

Since it is the highest cost form of capital, equity in too great a proportion increases costs to ratepayers, who both pay for too much high-cost equity and too little low-cost debt, and it reduces shareholders' chances to leverage a higher return out of their investment. It is necessary, therefore, to strike an appropriate balance with enough equity for safety but not so much that costs are unnecessarily high.

MERC proposed a capital structure comprised of 50.31percent common equity, 44.64 percent long-term debt, and 5.05 percent short-term debt.

MERC

Page 5 of initial brief.

The Company proposed to use the projected capital structure for the test year, 2014.

Department

Pages 54 through 56 of the Department's Initial Brief.

The Department accepted the Company's proposed capital structure.

Administrative Law Judge

The ALJ addressed capital structure in findings 66 through 69. In finding 69 the ALJ stated that MERC's proposed capital structure is reasonable and should be adopted in this case.

Capital Structure Alternatives

Some Commission alternatives for the capital structure are:

1. Use the Company's proposed capital structure comprised of 50.31 percent common equity, 44.64 percent long-term debt, and 5.05 percent short-term debt. (MERC, DOC, ALJ)

2. Determine that another capital structure is more appropriate.

(Note: These decision alternatives correspond to alternatives 106 and 107 on the deliberation outline.)

Cost of Debt

MERC

Page 5 of MERC's Initial Brief.

To calculate long-term cost of debt, MERC proposed using its actual cost of long-term debt of 5.5606 percent and a short-term debt rate of 2.3487 percent.

Department

Page 53 through 56 of the Department's Initial Brief.

The Department agreed that the proposed cost of debt is reasonable.

Cost of Debt Alternatives

Some Commission alternatives for the cost of debt are:

A. Long Term Debt

3. Adopt MERC's proposed cost of long-term debt of 5.5606 percent. (MERC, DOC, ALJ)

4. Adopt some other cost of long-term debt that the Commission considers more appropriate.

B. Short-term Debt

5. Adopt MERC's proposed cost of short-term debt of 2.3487 percent. (MERC, DOC, ALJ)

6. Adopt some other cost of short-term debt that the Commission considers more appropriate.

(Note: These decision alternatives correspond to alternatives 108 through 111 on the deliberation outline.)

Cost of Equity and Overall Cost of Capital

Background

As noted above, three parties supported cost of capital witnesses. MERC requested a return on equity of 10.75 percent, the Department recommended a return on equity of 9.29 percent, and the OAG recommended a cost of equity of 8.62 percent for rate setting purposes.

The cost of equity witnesses recommended that the Commission should authorize a rate of return on common equity that satisfies the requirements from the *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* 262 U.S. 679 (1923) and the *Federal Power Commission v. Hope Natural Gas Company* 320 U.S. 591 (1944) cases (together the "Bluefield and Hope" decisions). As discussed by Department witness Dr. Amit, the requirements from these cases are that:

1. The rate of return should be sufficient to enable the regulated company to maintain its credit rating and financial integrity.

2. The rate of return should be sufficient to enable the utility to attract capital at reasonable terms.

3. The rate of return should be commensurate with returns being earned on other investments having equivalent risks.

In findings the 74 through 77 the ALJ supported these standards.

Methods for Estimating Cost of Equity

DCF Method

Financial theory postulates that the price of the stock in the present period equals the present value of all the expected future dividends discounted by the appropriate rate of return. If annual dividends grow at a constant rate over an infinite period, the required rate of return on common equity capital can be estimated with the following formula:

> The expected (required) rate of return on equity = the expected dividend yield + the expected growth rate in dividends.

This formula, known as the Discounted Cash Flow (DCF) method, is a market-oriented method that requires the determination of the appropriate dividend yield and the appropriate growth rate to be used in this analysis.

A variation of the DCF model is the Two Growth Rate DCF (TGDCF). This model is sometimes used when an analyst thinks the short-term earnings growth rate may be either unusually low or unusually high and is not expected to be sustained. To the degree that such growth rates may not be sustainable in the long-run, the TGDCF method accommodates two different growth rates: short-term and sustainable, long-term growth rates.

Capital Asset Pricing Model

The Capital Asset Pricing Model (CAPM) defines risk as the relationship of a security's returns with the market's returns. This relationship is measured by beta ("β"), an index measure of an individual security's volatility relative to the market. A beta less than 1.0 indicates lower volatility than the market and a beta greater than 1.0 indicates greater volatility than the market. The CAPM assumes that all non-market, or unsystematic, risk can be eliminated through diversification and that investors require compensation for risks that cannot be eliminated through diversification.

The model is applied by adding a risk-free rate of return to a market risk premium. The market risk premium is adjusted proportionally to reflect the systematic risk of the individual security relative to the market as measured by beta.

Risk Premium Analysis

The Risk Premium Analysis (RP) is based upon the theory that the cost of common equity capital is greater than the prospective company-specific cost rate for long-term debt capital. The cost of equity is the expected cost rate for long-term debt capital plus a premium to compensate common shareholders for the added risk of being unsecured and last-in-line in any claim on the corporation's assets and earnings.

Methods Used by Parties

The Company's recommendation considered the results of the constant growth and multi-stage DCF model, the CAPM, and the Risk Premium approach. As a check on these results, MERC also considered the Comparable Earnings (CE) approach.

The Department based its recommendation on a DCF analysis. The Department also conducted CAPM and ECAPM which it stated was useful in confirming the reasonableness of the DCF estimates for the required rate of return on equity for MERC Energy.

The OAG based its recommendations on DCF with the CAPM as a check on the reasonableness of its DCF.

Cost of Equity Estimates

MERC

MERC addressed these issues on pages 5 through 25 of its Initial Brief and pages 1 through 12 of its Reply Brief.

Background

MERC is a Minnesota public utility solely devoted to providing natural gas service to Minnesota customers. MERC's stock is not traded in public markets. MERC argued that as a result, various financial models must be used to estimate a reasonable return on common equity that should be authorized for MERC.

MERC argued that the authorized return on equity provides a widely understood benchmark that investors can use to compare different investment opportunities. MERC claimed that it presented a full analysis of the appropriate return on common equity, developed through the use of several accepted financial models, and updated this analysis in its rebuttal testimony. Based on its analysis, MERC claimed its return on common equity should be set at 10.75 percent. Based on the increase in capital costs since MERC's last rate, it stated that if the Commission does not agree with a 10.75 percent ROE, the equity return in this case should be at least 10.27 percent.

MERC claimed that the record demonstrates that there are additional risk considerations, not included in the Department's and the OAG's analyses, that must be taken into account in order to determine a reasonable return on common equity for MERC. It claimed that the evidence shows that these additional risk considerations must be reflected in order for the return on common equity awarded in this case to meet the test set forth in Bluefield and Hope.

MERC's Analysis

MERC determined its cost of equity by considering the results of the cost of equity applied to market and financial data developed from a proxy group of the following thirteen gas and electric companies:

AGL Resources
Atmos Energy Corp.
Consolidated Edison, Inc.
Laclede Group Inc.
New Jersey Resources Corp
Northeast Utilities
PEPCO Holdings, Inc.
Piedmont Natural Gas
South Jersey Industries
Southwest Gas Corp
UIL Holding Corporation
WGL Holdings Inc.

MERC's cost of capital expert, Paul Moul, updated his models in Rebuttal Testimony and found that the updated market-based result of the DCF was 9.80 percent, the updated results of the RP model was 12.14 percent, and the updated result of the CAPM was 11.97 percent. The DCF saw a slight increase from Mr. Moul's direct testimony, the RP result showed a decline and the CAPM showed an increase. With one increase, one decrease, and one result remaining mostly unchanged, Mr. Moul maintained his recommendation of a 10.75 percent rate of return on common equity.

Mr. Moul noted that while the DCF is widely used as an input to rate of return determinations in utility rate cases, the model has limitations. The DCF analysis has circularity when applied to the utility industry because investors' expectations for the future depend on decisions of regulatory bodies. The regulatory bodies in turn depend on the DCF model to set the cost of equity, relying on investor's expectations that include an assessment of how regulators will decide rate cases. Therefore, the model may not fully reflect the true risk of a utility.

He also argued that the DCF model has limitations that make it less useful in the rate setting process where the firm's market capitalization diverges significantly from the book value capitalization. Because this limitation leads to a mis-specified cost of equity when applied to a book value capital structure, an analysis needs to incorporate the required adjustment to correct this problem.

Mr. Moul's risk premium analysis utilized the Moody's index of A-Rated Public Utility Bonds along with the forecast of interest rates provided in the Blue Chip Financial Forecast. For an equity risk premium, Mr. Moul looked to the Standard & Poor's (S&P's) Public Utility Index to describe the central tendency of historical returns on utility equity to determine a risk premium. He then adjusted that risk premium, determined from the general public utility index, to a lower number to reflect the risk of the gas group when compared with the S&P Public Utilities Index as a whole. The result was an updated ROE of 12.14 percent.

Using the CAPM model, Mr. Moul calculated a cost of common equity of 10.89 percent, after recognizing that the companies in the proxy group are entitled to a size adjustment based on their market capitalization.

Mr. Moul testified that a single method can provide an incomplete measure of the cost of equity depending on extraneous factors that may influence market sentiment. MERC argued that the record evidence supports Mr. Moul's recommendation of 10.75 percent. Because it is determined by using three financial models that account for different factors, it is more reasonable than a ROE calculation that relies on only one imperfect method.

MERC's Unique Risk Factors

MERC argued that the ROE must reflect the risk factors that are unique to MERC or MERC may be unable to attract sufficient capital. Mr. Moul testified that because Dr. Amit's and Dr. Chattopadhyay's recommended returns on equity do not account for the unique risks to MERC, Dr. Amit and Dr. Chattopadhyay have understated the cost of equity.

Company Size

MERC argued that smaller companies pose greater risks for investors. Mr. Moul testified that there has been extensive academic research that demonstrates the impact of size on investor expected returns. He claimed this is a separate factor from the Beta measure of systemic risk in explaining investor expected returns. All other things being equal, Mr. Moul claimed that, because a given change in revenue and expense has a proportionately greater impact on a small firm, a smaller company is riskier than a larger company.

MERC is several orders of magnitude smaller than the average companies' size in Mr. Moul's proxy group and the S&P Public Utilities Index. In the case of a low-cap market capitalization, a size premium of 1.23 percent is recommended by the 2013 Classic Yearbook for Stocks, Bonds, Bills and Inflation published by Ibbotson Associates. Mr. Moul adopted a size adjustment of 1.12 percent in this case, which represents the mid-cap adjustment. Applying the adjustment contributed to the difference between MERC's CAPM results of 11.97 percent and Dr. Amit's and Dr. Chattopadhyay's CAPM results of 9.79 percent and 10.09 percent.

MERC argued that Dr. Amit's reasoning for excluding the size adjustment is not properly applied in this case. It argued that Dr. Amit's proxy group is not comprised of utilities that are sufficiently similar to MERC.

MERC noted that Dr. Amit explicitly recognized that MERC has more financial risk than the comparison group used in his cost of equity analysis. Given that the Company's risk is observably different and absent a valid comparison between MERC and Dr. Amit's comparison group, a generically derived cost of equity obtained from Dr. Amit's group has little bearing on MERC's return requirements.

MERC noted that, with one exception, all of the companies in Dr. Amit's comparison group are mid cap in size, with an average capitalization of $2.6 billion. MERC's capitalization of approximately $205.9 million puts it in the small cap group. Dr. Amit's comparison group has no small cap companies like MERC.

MERC claimed that Dr. Chattopadhyay's reasons for declining to adopt a size adjustment are inappropriate in this case. MERC argued that the article cited by Dr. Chattopadhyay to discount the effect of size was authored twenty-one years ago and utilized data back to the 1960s. The article noted that non-regulated companies' Betas were higher than utilities' Betas. MERC argued that lower Betas do not invalidate the additional risk associated with small size and Beta is not the tool that should be employed to make a size determination.

MERC also noted that Dr. Chattopadhyay failed to include companies that would have made the risk portfolio of his proxy group more accurately reflect MERC's risk profile.

The idea that a size adjustment is not needed in this case is inaccurate. The central question is whether MERC, when compared to similarly situated companies, will be able to attract investors. Mr. Moul testified that all other things being equal, a smaller company is riskier than a larger company and unless MERC's cost of equity compensates for that additional risk, MERC is placed at a disadvantage against its larger counterparts.

Reliance on Large Volume Customers

MERC's risk profile is greatly influenced by the natural gas that it sells or delivers to large volume customers, representing approximately 79 percent of MERC's total throughput. MERC argued that with regard to these customers:

The large volume users have the ability to bypass the Local Distribution Company (LDC). MERC is at the mercy of the business cycle, the price of alternative energy sources, and pressures from competitors.

External factors can influence MERC's throughput to these customers because cost factors can impact their operations relative to alternative facilities located outside of MERC's service territory.

Mr. Moul's cost of equity accounts for this risk. Dr. Amit's does not.

Earning Variability, Operating Ratio, and Interest Coverage

Mr. Moul testified that when compared to the S&P Public Utilities and his proxy group of natural gas companies, MERC:

Has experienced much higher variability in its returns in a five-year period.

Has a higher five-year average operating ratio.

Had a lower interest coverage.

MERC claimed that these factors indicate a higher risk for MERC than for other natural gas companies and regulated utilities. Utilities with these characteristics will have a more difficult time attracting capital than a company that does not have them.

MERC noted that Mr. Moul's proposed cost of equity accounts for this risk while Dr. Amit's and Dr. Chattopadhyay's do not.

Additional Risk Factors

MERC claimed that there are additional risks not reflected in Dr. Amit's and Dr. Chattopadhyay's proposed cost of equity. Mr. Moul testified that leverage adjustments to the DCF and CAPM are necessary and that investors perceive additional risks in making equity investments. As a result, a conservative cost of equity is necessary for MERC to have the opportunity to attract capital. Dr. Amit's and Dr. Chattopadhyay's failure to consider these additional risk factors is unreasonable.

Mr. Moul computed a leverage adjustment for his DCF and CAPM analyses to reflect the fact that the market determined cost of equity used in the DCF and CAPM reflects a level of financial risk that is different from the capital structure stated at book value.

MERC argued that Dr. Amit's and Dr. Chattopadhyay's failure to compute a leverage adjustment in their DCF and CAPM analyses results in a market-determined cost of equity that understates MERC's necessary return on common equity.

Bluefield and Hope Factors

MERC argued that the rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher the required rate of return necessary to compensate for that risk. If public utilities are to attract the necessary investment capital on reasonable terms and because investors will consider the risk involved when seeking the highest rate of return available, the rate of return must at least equal the investor-required, market-determined cost of capital.

MERC claimed that Dr. Amit and Dr. Chattopadhyay are recommending costs of equity that are well below what investors would require from MERC. MERC compared Dr. Amit's recommended ROE to several other measures and stated:

> Of the eleven national rate cases for natural gas utilities decided by state utility commissions in the fourth quarter of 2013, the allowed average return was 9.83.
>
> Of the nineteen national rate cases for electric utilities decided by state commissions in the fourth quarter of 2013, the allowed average return was 9.89 percent
>
> Value Line's average rate of return for natural gas utilities is 11.49 percent for the 2017 through 2019 period.
>
> An update of the Commission's prior 9.70 percent approved equity return in MERC's last rate case results in a current return of 10.27 percent.
>
> The ROE approved by the Commission in the 2013 CenterPoint Energy gas rate case was 9.59 percent; and the ROE approved by the Commission in the 2012 Northern States Power electric rate case was 9.83 percent.

MERC claimed that, based on the returns established in other natural gas and electric regulatory proceedings, the returns that investors expect gas utilities to achieve, and the general state of capital markets, the Commission should not provide MERC with an equity return lower than 10 percent.

MERC claimed that Dr. Amit's cost of equity is on the lower end of the ROE as compared to at least one other gas utility in Minnesota. MREC claimed that Dr. Amit's proposed ROE would prohibit MERC from having a rate of return similar to a Minnesota natural gas LDC with comparable risk.

OAG witness Dr. Chattopadhyay's range of reasonable allowed returns on equity is 8.60 to 9.10 percent. His recommended cost of equity is 213 basis points below MERC's recommended ROE and the upper end of his ROE range is 165 basis points below MERC's recommended ROE. MERC argued that Dr. Chattopadhyay's ROE is so low that it is not credible in this case.

MERC argued that capital costs have increased since the Company's last rate case. The increase on Treasury bonds' yield demonstrates that Dr. Chattopadhyay's proposal in this case will not result in a reasonable return for MERC. Dr. Chattopadhyay seems inclined toward a low return because he bases his ROE recommendation, in part, on the fact that the Minnesota economy is performing well in comparison to other regions of the U.S. However, Dr. Chattopadhyay fails to show that MERC has benefitted from this general Minnesota phenomenon. MERC has experienced historically high earnings variability and its operating ratio is well above average; therefore, MERC requires an above average return on equity to compensate for its above average risk.

Market to Book

MERC noted that Dr. Chattopadhyay based his recommended ROE on the proposition that when market-to-book ratio is greater than one, the DCF results in an upwardly biased estimate of the cost of equity. Both MERC and the Department disagree with Dr. Chattopadhyay's conclusion that, when the market-to-book ratio is greater than one, the DCF analysis results in an upwardly biased estimate of the cost of common equity.

Mr. Moul testified that a review of the annual market-to-book ratios for natural gas utilities since 1958 illustrates that market-to-book ratios equal to 1.0 are unusual and market-to-book ratios greater than 1.0 are common. The average market-to-book ratio over the past 55 years is 1.6. Both regulators and investors are aware that market-to-book ratios exceed one and, even though regulators are aware of these market-to-book ratios, they still grant utilities' rate increases. If Dr. Chattopadhyay's theory were correct, regulators would grant lower rate increases and lower authorized returns on equity any time those ratios were above one.

Dr. Amit testified that the market-to-book ratios for both Dr. Chattopadhyay's and Mr. Moul's comparison groups remained significantly above one for the period 2008 through 2013 and trend upward over the period 2009 through 2013. Dr. Amit's comparison group's market-to-book ratio did not go below 1.719 during the period 2003 through 2013. If Dr. Chattopadhyay's hypothesis is to be believed, investors investing in the gas comparison group have received excessive returns for a period of least ten years. Such a sustained excessive return over such a long time period is counter to basic financial principles. If excessive returns were true, they would have produced a run on gas utility stocks until the excessive profits were eliminated and market-to-book ratios would have reverted to (near) one which did not happen. MERC argued that the financial literature cited by Dr. Chattopadhyay does not support his upwardly biased ROE claim and, when the market-to-book ratio equals one, Dr. Chattopadhyay's own empirical studies produce unreasonably low ROEs.

The record evidence demonstrates that, when compared to the widely-referenced Value Line industry forecasts for 2017-2019, Dr. Amit's recommended ROE of 9.29 percent is 220 basis points lower and Dr. Chattopadhyay's recommended ROE of 8.62 percent is 287 basis points lower.

Mr. Moul testified that to obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. Therefore, if investors are requiring a rate of return that is consistent with the industry forecasts, Dr. Amit's and Dr. Chattopadhyay's costs of equity would harm MERC's chances of meeting investor expectations. MERC argued that Dr. Amit's and Dr. Chattopadhyay's rates of return are not sufficient to enable the utility to attract capital, and do not meet the Bluefield and Hope test for a fair and reasonable rate of return.

Flotation Cost

MERC argued that, in order to allow a utility to earn its reasonable rate of return, a flotation cost adjustment is common and necessary. MERC's inclusion of a flotation cost adjustment conforms to the Commission's past practice of recognizing the issuance expense of capital when calculating a reasonable return with unadjusted stock prices. Dr. Amit testified that, when companies issue equity, new shares' price paid by investors is higher than the proceeds per share received by the company. The difference, known as issuance or flotation costs, is the issue's fees and expenses paid by the Company.

Based on his calculations, Mr. Moul proposed a 14 basis points flotation cost adjustment and Dr. Amit proposed a 15 basis points adjustment.

OAG witness Dr. Chattopadhyay testified that the flotation cost should not be recognized in this case. Dr. Chattopadhyay argued that, where the market-to-book ratio is greater than one, the DCF produces a ROE that is upwardly biased and, therefore, already accounts for flotation cost adjustment.

MERC claimed that Dr. Chattopadhyay's argument is without merit because failure to modify the DCF analysis for flotation costs results in an understatement of the required rate of return on common equity. Moreover, Dr. Chattopadhyay's inclusion of external financing growth in his DCF analysis mandates a flotation cost adjustment. Dr. Chattopadhyay incorrectly argued that, with his proposed rate of return on common equity, there is an adequate cushion to cover flotation costs. MERC argued that these costs exist regardless of the market-to-book ratio and are no different than the recovery of issuance expenses associated with selling long-term debt to investors.

MERC Reply Brief

Pages 1 through 12 of MERC's Reply Briefs.

Response to ROE Criticisms

MERC's Reply Briefs restated many of its arguments. It argued that its ROE recommendation is supported by three recognized financial models.

MERC stated that the fact that the fourth quarter 2013 Commission decisions may be based on data from 2012 and early 2013 only substantiates MERC's assertion that, to account for the increase in MERC's capital costs since the Company's last rate case, the Company's ROE must increase. It noted that the fourth quarter 2013 highest ROE of 10.25 percent is only 2 basis points lower than the 10.27 percent ROE that MERC has indicated it would accept.

In response to the Department's claim that MERC's "updating" argument regarding the cost of equity is unreasonable and must be rejected, MERC claimed that it has sufficiently demonstrated that an update of the Commission's prior 9.70 percent approved equity return in MERC's last rate case results in a current return of 10.27 percent.

Response to DCF, RP, and CAPM Criticisms

MERC argued that, for its dividend yield calculations, it was appropriate to use six month historical prices rather than shorter-term (i.e., one to three month) prices because the use of the six-month average dividend yield will reflect current capital costs, while avoiding spot yields.

DCF

MERC and the Department agreed that the flotation cost calculation should be 3.90 percent. The Department disagreed with MERC's adjustment procedure, but not the flotation cost adjustment amount. Since MERC engaged in a detailed growth rate analysis, the Company stated that the Department's claim that MERC's projected growth rate is subjective and, therefore, unreasonable is false. Further, MERC's expected growth rate of 5 percent falls within the array of earnings per share growth rates shown by the relevant analysts' forecasts and is actually lower than Dr. Amit's 5.12 percent mean projected growth rate.

RP Analysis

MERC claimed that the Department improperly criticized MERC's yield and risk premium for the Company's RP analysis and MERC's risk-free rate of return and market premium choices for the Company's CAPM analysis.

Despite the Department's concerns, MERC's historical risk premium approach is appropriate in this rate case and MERC did not use the wrong yield on A-rated utility bonds nor the wrong risk premium. Despite recent financial literature indicating that prospective risk premiums may be preferable to risk premiums estimated based on historical data, the use of historical data is appropriate here. MERC claimed that the use of yields on A-rated utility bonds is preferable for this case because it allows the RP approach to conform with a forward-looking cost of equity and aligns the premium derived from historical data with the prospective level of interest rates.

CAPM

MERC claimed that the beta of 0.86 is appropriate and reflects the financial risk associated with a rate-setting capital structure that is measured at book value. The yield on thirty year Treasury bills does represent a risk-free yield. MERC stated that forecasts of interest rates must be emphasized in selecting the risk-free rate of return in the CAPM. The Company's risk-free yield considers not only the Blue Chip forecasts, but also the recent trend in the yields on long-term Treasury bonds.

MERC explained that it used a different risk premium for its RP analysis than its CAPM analysis because the equity risk premium component of MERC's RP model is aligned with the yields on A-rated public utility bonds and the market premium in the CAPM is aligned with the risk-free rate of return.

The ten year Treasury Bond rates used by the OAG in its CAPM analysis are inappropriate because they result in a rate that is too low for the risk-free rate of return component of the CAPM for the 2014 test year and the rate's effective period.

CE Analysis

MERC claimed that the CE method is valuable because, unlike the DCF and CAPM, the results of the CE method, when the market capitalization and book capitalization diverge significantly, can be applied directly to the book value capitalization and does not contain the potential misspecification contained in market models.

MERC's Unique Risk Factors

Size

MERC stated that the Department's and the OAG's Proxy Groups do not include a size adjustment and do not properly reflect MERC's unique risk factors. MERC's proxy group contained thirteen gas and electric companies and their inclusion is appropriate because the electric companies included in MERC's proxy group are primarily delivery companies. MERC claimed that its investment risk is higher than that of MERC's proxy group.

Addressing the Department's discussion of macro and micro risk analysis, MERC stated that, to ensure that the Company's ROE is not understated, it is necessary to consider MERC's unique risk factors. It claimed that the Department incorrectly argued that MERC's proposed size adjustment would isolate a unique risk factor for MERC and would disregard all other risk factors that may be unique to other utilities in the Company's comparison group.

MERC noted that the Department has explicitly recognized that MERC has more financial risk than the proxy group used in the Department's equity analysis. The OAG admits that its proxy group contains several companies with substantial nonregulated activities that present a different risk profile than MERC; however, investment risk profile difference between the OAG's proxy group and MERC's proxy group does not benefit MERC.

MERC claimed that the OAG's failure to recognize a size adjustment is flawed because the OAG relied on dated academic research and removed companies that would have made the OAG's proxy group's risk portfolio more accurately reflect MERC's risk profile. The record demonstrates that a size adjustment is necessary because MERC is smaller than the companies in MERC's, the Department's, and the OAG's proxy groups, and the average utility.

Leverage Adjustment

MERC restated its argument that a leverage adjustment is appropriate. It added that, contrary to the Department's and the OAG's assertions, MERC's leverage adjustment does not ignore the fact that utility investors are aware that a utility's earnings are based on an allowed return granted by regulators on the utility's book value. A leverage adjustment is appropriate because it recognizes that a market determined cost of equity reflects a level of financial risk that is different from the capital structure stated at book value using standard rate setting practices.

MERC argued that the Department's and the OAG's failure to compute a leverage adjustment in their DCF and CAPM analyses results in a market-determined cost of equity that understates MERC's necessary return on common equity.

Flotation Cost

MERC stated that the OAG's analysis is flawed because it fails to include a flotation cost adjustment. It noted that both the Company and the Department argued that a flotation cost adjustment is necessary.

MERC Recommendation

MERC Energy requested that the Commission approve the following capital structure and overall cost of capital for the Company:

Capital Component	Percent of Capital Structure	Cost of Component	Weighted Cost
Long-Term Debt	44.64 %	5.5606 %	2.4822 %
Short-Term Debt	5.05 %	2.3487 %	0.1186 %
Common Equity	50.31 %	10.75 %	5.4084 %
Total	100.00 %		8.0092 %

Department ROE Analysis

Department discussion of these issues can be found on pages 11 through 56 of its Initial Brief, and pages 2 through 14 of its Reply Briefs.

Fair Rate of Return for MERC

The Department noted that the cost of equity capital to MERC is the rate of return that it may pay to investors to induce them to invest in its regulated operations. To estimate this cost, Department witness Dr. Amit used a market oriented approach and relied on the concept of "opportunity costs." The Department initially recommended an ROE of 9.40 percent on MERC's common equity capital and an overall rate of return of 7.3299 percent on MERC's total capital.

Relying on the most recently available dividend yields and expected growth rates for companies in his comparable group, Dr. Amit, in the Department's Surrebuttal Testimony, updated his ROE recommendation to 9.29 percent, with an overall cost of capital of 7.27 percent. Dr. Amit's updated ROE recommendation is eleven basis points lower than his initial recommendation of 9.40 percent, and is a decrease in the overall cost of capital of six basis points, from 7.33 percent to 7.27 percent.

Cost of Equity

Dr. Amit relied primarily on the Discounted Cash Flow method of determining a reasonable cost of common equity for MERC. Dr. Amit, in his Direct Testimony analysis, applied the Two Growth Rate DCF to one company (NJR) because of the company's relatively low growth rate in comparison to the mean expected growth rate for a group of comparable companies he called the Natural Gas Distribution Comparison Group (NGCG). In Surrebuttal, Dr. Amit applied the TGDCF to three companies (ATO, NWN and PNY) because he determined that the updated projected growth rates for the three companies were outside the reasonable range of the comparable group.

The Department recommended that the Commission adopt an ROE of 9.29 percent for MERC based on the Department's DCF analysis, as confirmed by other analyses.

Comparable Group

Because MERC is a subsidiary of Integrys Energy Group and not publicly traded, a DCF analysis cannot be directly performed on MERC. Alternative applications of the DCF model are to perform a DCF on the parent company or a group of companies with investment risks similar to that of the company, in this case, MERC.

The Department stated that in 2012, Integrys received a fairly small percent of its net income from its natural gas distribution operations (33.1 percent). Therefore, a DCF analysis directly applied to Integrys could not provide important or useful information regarding the cost of equity for MERC. The Department added that a DCF analysis on one company alone may be more sensitive to the random nature of stock prices and the analyst's specific growth-rate predictions. For these reasons, Dr. Amit did not include a DCF analysis of Integrys.

The Department performed a DCF analysis on a group of companies with investment risks similar to that of the division company (MERC). To estimate the cost of equity for MERC, Dr. Amit used DCF and TGDCF analyses for comparable groups. He used the Capital Asset Pricing Model (CAPM) to check the reasonableness of the results of the DCF and TGDCF analyses.

Because companies with similar investment risks are expected to have similar required rates of return, the goal of selecting a comparable group for a DCF analysis is to find companies, from an investor's perspective, with investment risks similar to MERC's. MERC's main line of business is natural gas distribution, which has the Standard Industrial Classification (SIC) code of 4924. The Department chose a group of companies that have investment risk comparable to MERC by applying the following criteria or screens:

Are listed on the Compustat Research Insight data base of September 30, 2013, and

Have an SIC code of 4924,

Are traded on one of the stock exchanges,

Have Standard & Poor's (S&P) bond ratings within the range of BBB to AA (the rating of MERC's holding company, Integrys, is A-),

In 2012, had at least 60 percent of total net operating income from natural gas distribution operations.

Added companies that were listed in Value Line Investment Survey of September 6, 2013 as natural gas utilities and met the above criteria.

Have both a beta and standard deviation of past price changes that deviated by no more than one standard deviation from the mean of the companies that met the five screens noted above.

The Companies that met these criteria are:

Company	Ticker
AGL Resources	GAS
Atmos Energy	ATO
Laclede Group, Inc.	LG
New Jersey Resources Corp	NJR
Northwest Natural Gas	NWN
Piedmont Natural Gas	PNY
South Jersey Industries Inc	SJI
WGL Holdings Inc	WGL

Department witness Amit called this group "The Natural Gas Distribution Comparison Group" (NGCP). Based on common equity ratios and long-term debt ratios for NGCG and MERC, and the fact that MERC and the companies in the NGCP are in the same line of business (natural gas distribution), and are similarly state-regulated, Dr. Amit concluded that MERC's investment risks are reasonably similar to the investment risks of the companies in the comparison group.

DCF Analysis

Expected Growth Rate

Under DCF methodology, the required rate of return is equal to the expected growth rate of dividends plus the expected dividend yield. For the first component, Dr. Amit testified that historical growth rates in the NGCG may be poor indicators of their future growth rates because most utilities' returns on equity and dividend payout ratios have not remained constant, and growth in book value has occurred due to retained earnings as well as issuance of new shares of common stock.

For the growth rate, Department witness Dr. Amit used the projected growth rates in earnings per share (EPS) provided by three widely-used and respected investor services: Zacks Investment Research (Zacks), The Value Line Investment Survey (VL), and First Call Consensus long-term earnings growth rate estimate provided by Thomson Financial Network (Thomson).

The Department argued that the analysts' projected growth rates are superior to historical growth rates and, among projected growth rates, the EPS growth rate is the most appropriate to use. Sole reliance on the projected EPS growth rate only is reasonable for several reasons including that the long-run sustainable dividends' growth is solely driven from earnings' growth.

In Surrebuttal, the Department, based on the most recently available projected growth rates, updated the projected growth rates for the NGCG. They ranged from 4.14 percent to 6.25 percent with an average of 5.12 percent. Dr. Amit argued that some projected growth rates for certain companies in the NGCG were not reasonable to be used as proxies for the DCF's long-term sustainable growth. To adjust for these, Dr. Amit applied a TGDCF to ATO, NWN and PNY, for an average dividend yield for the NGCG of 5.27 percent.

Expected Dividend Yield

The other component, the expected dividend yield, is calculated using the current price and the dividend in the next year. The Department argued that, because share prices are very volatile in the short run, using historical prices in calculating the expected dividend yield would be inappropriate.Therefore, it is necessary to use a recent period of time that is short enough to avoid irrelevant historical prices and long enough to avoid short-term aberrations in the capital market. To address these concerns, the Department used the most recently available 30-day closing prices for the calculation.

In Surrebuttal Testimony the Department updated the dividend yield estimate to reflect more recent data. It used the 32-day closing prices for the period ending April 14, 2014. These ranged from a low of 3.84 percent to 3.88 percent, with a mid-point of 3.86 percent. The Department's dividend yield included an increase by one half of the expected growth rates.

DCF Recommendation

Based on the updated analysis, the Department's DCF analysis ranged from 8.23 percent to 10.19 percent with a mean of 9.14 percent. After adjusting for flotation costs, the cost of equity ranged from 8.38 percent to 10.35 percent with a midpoint of 9.29 percent.

CAPM Analysis

As a check on the results of the DCF/TGDCF, Dr. Amit updated his CAPMM estimates. With flotation costs, his CAPM was 9.79 percent.

Flotation Costs

The Department agreed with MERC that the DCF and TGDCF analyses must be adjusted to allow for the cost of issuing new shares of common stock without causing dilution. The Department argued that recovery of flotation costs, even if no new issuances are planned in the near future, is appropriate because failure to do so may deny MERC the opportunity to earn its required rate of return in the future.

Dr. Amit agreed with the Company's flotation cost calculation of 3.90 percent and used it to adjust his DCF results.

The Department argued that the OAG's recommendation to exclude a flotation cost is based on a view that the DCF methodology produces an upward biased ROE when the market-to-book ratio (M/B ratio) of comparable companies is greater than one. Because this premise is not well-supported, the Department concluded that the OAG's objection to the inclusion of flotation costs is without foundation.

Comments on the Company's Analyses

The Department stated that MERC failed to demonstrate that a 10.75 percent ROE for MERC, with flotation costs, is reasonable. The Department stated that its main disagreements with the Company's analysis are:

The leverage adjustments for DCF and CAPM analyses.

The size adjustment to the CAPM.

Mr. Moul's choices of the yield and risk premium for the risk period analysis.

Selection of Comparable Group

The Department stated that a key error in the Company's selection of a comparable group was the inclusion of four non-natural gas utility companies with higher risk profiles than natural gas utilities such as MERC. The Department argued that it is reasonable to expect a higher average required rate of return for the four companies than for the Delivery group excluding the four companies. An appropriate comparable group would result in a lower required rate of return than that indicated by Mr. Moul's Delivery Group. Because it does not have a comparable risk profile to that of MERC, the comparable group for Mr. Moul's DCF analysis is flawed and, therefore, inappropriate.

DCF Flaws

The Department claimed that flaws in Mr. Moul's DCF analysis include:

His dividend yield calculations.
Calculation of the adjustment for flotation costs.
The projected growth rate.

The Department stated that Mr. Moul's dividend yield calculations were flawed by his use of month-end prices over of six-month period rather than current stock prices over a short period, such as a one to three month period. Under the basic financial premise that financial markets are efficient the Department argued that it is important to use current rather than non-recent historical prices for the dividend yield. Mr. Moul's use of prices over a six-month period to calculate his dividend yields may be inappropriate. Using a six-month average dividend yield may create a mismatch between such dividend yields and the more recent projected growth rates.

Regarding the flotation cost adjustment Dr. Amit agreed with MERC's calculation of flotation costs of 3.90 percent, but not Mr. Moul's adjustment to the dividend yield which is well-recognized in the financial literature as follows: Dividend yield/1-F, where F is the percentage flotation cost or 0.039 in this case.

Mr. Moul's projected growth rate in dividends used projected earnings per share, yet he concluded that an expected growth rate of five percent is a reasonable growth rate to use for his DCF analysis. To eliminate any subjective judgment, Dr. Amit proposed to average analysts' projected growth rate, 5.21 percent, and to substitute that average for Mr. Moul's proposed 5.00 percent.

The Department noted that Mr. Moul's Rebuttal Testimony did not correct these flaws in his DCF analysis.

MERC's Risk Premium Analysis

The Department claimed that MERC's risk premium analysis is flawed for several reasons. Mr. Moul used the wrong yield on A-rated utility bonds and the wrong risk premium for his Risk Premium analysis; as a result, his RP analysis should be rejected.

The Department stated that Mr. Moul, for his Risk Premium analysis, used the wrong methodology to estimate the yield on A-rated utility bonds; therefore, his proposed yield is upwardly biased. Mr. Moul inappropriately used mismatched time periods (he added a yield spread between twenty-year Treasury bills and A-rated utility bonds to the yields on thirty-year Treasury bills), he did not calculate average yield spreads based on the most recently available information (his six-month or twelve-month averages may reflect outdated information), and he used estimated spreads rather than the preferable direct information on A-rated utility bonds.

The Department stated that Mr. Moul's determination of the yield for his risk premium is somewhat arbitrary and; therefore, inappropriate. Based on recent financial literature, there is a consensus that risk premiums vary based on the specific financial and economic environments; therefore, prospective risk premiums may be preferable to risk premiums estimated based on historical data. Although Mr. Moul used a historical risk premium approach, he failed to establish an exact analytical relationship between the level of interest rates and the level of risk premium. His estimated risk premium is based on his own judgment that is not supported by any rigorous analysis.

The Department stated that Mr. Moul incorrectly calculated his risk premium based on mismatched measurements. The risk premiums estimated by Mr. Moul are measured incorrectly as the return on large common stock minus the return on long-term corporate bonds. The appropriate risk measures should be calculated as the difference between the return on common stock of A-rated utility companies and the return on long-term A-rated utility bonds.

The Department stated that, in his rebuttal testimony, Mr. Moul repeated the same Risk Premium analysis' errors committed in his Direct Testimony. He provided no additional explanation regarding his choice of the yield on A-rated utility bonds and the risk premium. The Department concluded that Mr. Moul's Risk Premium analysis is unreasonable.

Company CAPM methodology

Department witness Dr. Amit claimed that there were significant flaws in Mr. Moul's CAPM analysis. To perform a CAPM analysis there are three main parameters: beta, the risk-free rate, and risk premium. Mr. Moul's CAPM analysis is flawed as to each of the parameters and he repeated the same errors in his Rebuttal Testimony.

MERC's beta is unreasonably high. For beta, Mr. Moul appropriately selected Value Line's beta of 0.67, then adjusted it to 0.71 to account for MERC's alleged higher financial risk. Based on the Company's failure to demonstrate such a higher financial risk, Dr. Amit disregarded Mr. Moul's proposed beta adjustment.

For the risk-free rate, based on the Blue-Chip forecast of 3.70 percent yield on thirty-year Treasury bills for the third quarter of 2014, the Company used 3.75 percent. The Department identified two key concerns with Mr. Moul's risk-free rate. First, the yield on thirty-year Treasury bills includes interest risk premium and therefore does not represent a true risk-free yield. Second, because current yields on long-term Treasury bills fully reflect current investors' expectations about the future economic and financial environment, Mr. Moul's use of Blue-Chip's forecast of future yields for current yields is inappropriate; doing so simply introduces another element of uncertainty in the application of the CAPM.

For these reasons, Dr. Amit substituted the current (September, 2013 average yield) 3.53 percent yield on twenty-year bonds for Mr. Moul's proposed risk-free yield of 3.75 percent.

For the risk premium, Mr. Moul's methodology is inconsistent and unreasonable. Specifically, the Company used a 7 percent premium for the Risk Premium analysis and 8.69 percent for its CAPM historical risk premium. Further, Mr. Moul's use of a historical risk premium for his CAPM analysis is inappropriate as is Mr. Moul's use of the average of current and historical risk premiums. Dr. Amit argued that Mr. Moul's methodology of calculating the historical risk premium is incorrect, both for Mr. Moul's Risk Premium analysis and for his CAPM.

Finally, although Mr. Moul's calculations of the market's rate of return are reasonable, his use of a risk-free rate of return of 3.75 percent rather than 3.53 percent was not.

Comparable Earning Analysis

The Department stated that, together with the arbitrary elimination of companies from the comparison group, the Company's Comparable Earning analysis' results, show that the analysis is without merit and must be rejected. Dr. Amit argued that the results of Mr. Moul's analysis indicate that his selected group includes many companies that are not risk comparable to the investment risks of his Delivery group. Before Mr. Moul arbitrarily eliminated companies from the group with returns greater than 20 percent, his average returns were 48.9 percent and 17.9 percent for the historical and projected periods, respectively.

Other indicators of problems with the Comparable Earning analysis include:

> Historical returns include returns as low as 3 percent and as high as 726.5 percent;
>
> Projected returns range from a low of 4.5 percent to a high of 41.5 percent;
>
> About thirty-nine percent of the companies have average historical returns above twenty percent; and

> About thirty-two percent of the companies have average projected returns greater or equal to twenty percent.

MERC Risk-Specific Adjustments

The Department stated that the risk adjustments to ROE proposed by Mr. Moul are without merit. He included the same risk indicators in his Direct and Rebuttal Testimonies, divided into two groups:

> Risk indicators for which Mr. Moul did not provide specific upward adjustments of his recommended ROE; and
>
> Risk indicators for which Mr. Moul provided specific upward adjustments of his recommended ROE a size and a leverage adjustment.

Regarding Mr. Moul's first group of claimed risk indicators, Dr. Amit argued that there is no valid basis to conclude that MERC's investment risk is greater than Mr. Moul's Delivery Group investment risk.

As to the second group of claimed risk indicators, Dr. Amit argued that Mr. Moul's proposed upward adjustments to his ROE estimates are without merit.

The Department claimed that selection of a comparison group requires a macro risk analysis, not Mr. Moul's proposed micro risk analysis. Mr. Moul's micro risk analysis of companies in his comparable or Delivery group is an unreasonable basis for MERC's ROE adjustment.
A macro risk analysis is based on using well accepted, readily available business and financial risk indicators. Companies in the comparison group must have similar business and financial risk indicators, which may include lines of business, credit rating, beta, and standard deviation of price changes. Although each company in the comparison group may have unique characteristics that impact its investment risk, there are two key reasons why using micro risk analysis to identify such characteristics is not appropriate for the purpose of selecting a comparable group. First, since each utility has a somewhat different set of risk characteristics, screening for micro risk factors would divide the group too finely such that no company would qualify to be selected for the overall comparison group. Second, the macro risk analysis uses well accepted risk measures that already reflect the unique characteristics of each company. Performing a micro analysis would overemphasize the micro characteristic and, thus, is unreasonable.

The Department stated that Mr. Moul did not show that, according to his CAPM analysis, his upward ROE adjustment for MERC's size is reasonable. He stated that, based on various studies and the financial literature, smaller size companies are riskier than larger size companies and; therefore, smaller size companies' required rate of return is higher. He identified a 1.12 percent risk premium for his CAPM projected ROE for a Mid-Cap company and used that premium as an adder for his CAPM result. There exists a "risk premium" for smaller size companies, but only if all other investment risk characteristics of a group of companies are the same. For two identical companies, in all aspects other than size, the company that is significantly smaller would have a higher required rate of return. Mr. Moul made no such showing as for MERC.

MERC's size is only one aspect of the Company's overall financial and business risk. The Department argued that it is inappropriate to choose one specific factor of the overall investment risk and use it increase MERC's required rate of return to a level that is higher than the rate of return for the comparison group.

The Department argued that Mr. Moul's 48 basis points upward ROE adjustment based on a "leverage" is also unreasonable. Mr. Moul used two equations that would be appropriate equations to account for significant differences in the debt-to-equity ratios for two companies with otherwise similar investment risks, but neither equation is applicable for MERC and Mr. Moul's Delivery group. Mr. Moul's application of these equations contradicts the fundamental financial principle that financial markets are efficient and that current stock prices fully reflect all publicly available information. This principle applies as well to investors' expectations regarding risk premiums.

For these reasons, making an upward "leverage adjustment" to MERC's ROE is not reasonable and should be denied.

Response to MERC's Additional Arguments

In his Rebuttal Testimony, Mr. Moul made three new arguments for a higher MERC ROE, Mr. Moul claimed that:

> In view of the rates of return allowed by state utility commissions in 2013, Dr. Amit's recommendation of rate of return of 9.40 percent is too low.
>
> Dr. Amit's recommended rate of return of 9.40 percent is too low because Value Line projects an average rate of return of 11.49 percent for its natural gas utility companies over the 2017–2019 period.
>
> Based on the Commission's Order in Docket No. G007,011/GA-10-977, the required rate of return for MERC should be 10.27 percent.

In response to these comments, the Department stated:

> Recent state utility commission decisions do not support Mr. Moul's proposed ROE for MERC. Contrary to Mr. Moul's claim, recent commission decisions do not show that Dr. Amit's recommended ROE is too low. The average ROE for the group of eleven natural gas rate cases determined in the fourth quarter of 2013, was 9.83. The range of those allowed ROEs went from a low of 9.08 percent to a high of 10.25 percent. Based on Mr. Moul's own argument, his recommended ROE of 10.75 percent is unreasonably high.
>
> There are at least two reasons why Mr. Moul's contention that Value Line's projected expected ROE of 11.49 percent for the period of 2017–2019 does not show Dr. Amit's recommended MERC ROE to be too low. First, as Dr. Amit provided in his Rebuttal Testimony at pages 2 and 3, when the market-to-book (M/B) ratio is greater than one, as is the case for Dr. Amit's comparison group,

then the expected rate of return is greater than the cost of common equity. The issue in this rate concerns a reasonable cost of common equity (the required rate of return or ROE) for MERC. Second, the Value Line data is internally inconsistent.

The Commission's Order in MERC's last rate case, Docket No. G007,011/GA-10-977, does not support an ROE in this case of 10.27 percent. Mr. Moul employed a circular argument to erroneously claim that the Commission's prior ROE, which was based on 2011 data, is appropriate to use in determining the ROE in the present rate case of 10.27 percent. Also, Mr. Moul assumed, without support, that today's interest rate environment required his historical risk premium that was incorrectly determined in the past to be adjusted downward by 50 basis points.

Comments on the OAG's Analysis

The Department claimed that the OAG's recommendation of an 8.62 percent ROE is fundamentally unreasonable and based on the erroneous assumption that when the M/B ratio is greater than one, the DCF produces an upwardly biased DCF estimate of ROE. The OAG's projected growth rate is based on a subjective average of several growth rates that achieves a low ROE, but with no explanation of why it would not be reasonable to employ a similarly subjective average of growth rates to achieve a higher ROE.

Dr. Amit disagreed with certain aspects of Dr. Chattopadhyay's DCF ROE analysis and recommendation. Dr. Amit's final recommended ROE for MERC of 9.29 percent differs from Dr. Chattopadhyay's 8.62 percent recommendation largely due to Dr. Chattopadhyay taking an average of the results of four different DCF methods and his view that application of DCF analysis results in an upward bias to ROE where, as here, the market-to-book (M/B) ratio of comparable companies is over one.

Dr. Amit's disagreements with Dr. Chattopadhyay's analyses include:

Dr. Chattopadhyay's use of various expected growth rates.

Dr. Chattopadhyay used Value Line projected 2014 dividend rates.

Dr. Chattopadhyay based his overall recommendation on the premise that when the market to book ratio is greater than one, the DCF results in an upward bias estimate of the cost of equity.

Dr. Chattopadhyay's hypothesis, for at least the last ten years investors in natural gas utilities received returns above the cost of equity.

Dr. Chattopadhyay's objection to the inclusion of flotation costs is solely based on his argument that the DCF produces an upwardly biased ROE when the market-to-book ratio is greater than one.

Growth Rates

The Department stated that Dr. Chattopadhyay's calculation of the expected growth rates by averaging the expected EPS, DPS and BPS is based on a flawed assumption. The Department argued that econometric models support the use of projected EPS-only growth rates. The Department stated that Dr. Chattopadhyay incorrectly argued that, because investors consider various factors when they price utility stock, it is reasonable to average expected earnings per share, dividends per share and book value per share values to reflect investors' expectations of dividend growth rates.

The Department stated that Dr. Chattopadhyay is correct that the DCF assumes the same growth rates for EPS, DPS and BPS. However, it is incorrect to obtain the projected sustainable growth rate for DCF analysis by averaging projected EPS, DPS and BPS. It stated that the long-run DPS and BPS (sustainable) growths are derived from EPS growth. Therefore, conceptually, the issue of unequal short-term growth rates is more appropriately resolved by assuming convergence of the DPS and BPS growth rates to the sustainable EPS growth rates, not by averaging the EPS, DPS and BPS growth rates.

The Department argued that the importance of dividends to the investor community is irrelevant. Although investors, in making their investment decisions, rely on factors other than earnings per share, the issue in this rate case is which projected growth rate is the most appropriate to use in a DCF analysis.

The Department argued that Dr. Chattopadhyay's growth rate regression analysis did not show that DPS or BPS projected growth rates are useful in predicting natural gas utilities' stock prices. To be able to compare his regression analysis with Dr. Chattopadhyay's, Dr. Amit ran three regressions and concluded that his econometric models' results support his position that projected EPS growth rates are the most appropriate for a DCF analysis. Dr. Amit noted that Dr. Chattopadhyay's selection of the particular growth rates to use in his DCF analysis is not adequately supported by theory nor by the regression analysis in Dr. Chattopadhyay's Direct or Rebuttal testimonies. For example, the weights that Dr. Chattopadhyay assigned to each of his selected growth rates "are arbitrary." The Department argued that all of the analyses indicate that the EPS growth rate is the most appropriate to use in DCF analyses.

Market to Book Ratio

The Department disagreed with the OAG's argument that when the M/B ratio is significantly higher than one, the DCF analysis would produce a required rate of return greater than the cost of equity capital. The Department claimed that the theory of an upward bias for ROE based on a M/B ratio greater than one fails to recognize that, in a rate case, the issue is to determine a reasonable cost estimate of common equity rather than to estimate investors' expected realized rate of return on their investment. The OAG's analysis fails to recognize that the DCF analysis produces an estimate for common equity costs, not the expected realized rate of return.

In a rate case, it is necessary to estimate the cost of common equity, which may or may not be, equal to he expected realized rate of return. The fact that, when M/B>1, the required rate-of-return on equity is smaller than the expected return does not indicate an excessive ROE for ratemaking purposes.

The Department argued that Dr. Chattopadhyay did not show that the DCF analysis results in an upward bias in the estimate of the cost of equity. Under the fundamental principle that financial markets are efficient, stock prices fully reflect all available public information. Thus, the DCF analysis fully reflects all publicly available information via stock prices. Further, investors are fully aware of the fact that M/B ratios for gas utilities are greater than one. Therefore, DCF analyses for the comparable groups of Dr. Chattopadhyay, Mr. Moul, and Dr. Amit fully account for the information that M/B ratio is greater than one, and do not produce an upward biased estimate of the cost of common equity for MERC.

Dr. Amit explained that Dr. Chattopadhyay's M/B ratio analysis only shows that, when the M/B ratio is greater than one, the expected realized rate of return is greater than the cost of common equity. Nowhere in his testimony did he show that, under such circumstances, the DCF analysis results in an upward bias in the estimate of the cost of equity.

OAG Elimination of Flotation Costs

The Department restated its argument that the required rate of return on equity must include a flotation cost adjustment. The Department disagreed with the argument that, when the M/B ratio is greater than one, flotation costs should be excluded because it resulting upward bias in the DCF estimate. The Department argued that such a bias has not been demonstrated and that it would be inappropriate to disallow a legitimate cost.

Department Reply Brief

Pages 2 through 14 of Reply Brief.

Department Response to MERC

The Department stated that, consistent with the testimony of MERC witness Mr. Moul, the Company's Initial Brief urges the Commission to adopt MERC's flawed analyses of three financial methods, DCF, CAPM and Risk Premium and to use subjective judgment to blend those analyses into a final ROE for MERC.

Proxy Group

The Department stated that MERC's proxy group is not comparable in risk to MERC. A key flaw is the inclusion of four non-gas companies that have higher risk characteristics than MERC's. Because those companies have risk profiles higher than the remaining companies in Mr. Moul's proxy group, it is reasonable to expect a higher average required rate of return for those companies than for MERC's proxy group without the non-gas companies.

The Department stated that MERC's criticisms of Dr. Amit's proxy group are not valid. The Department noted that Dr. Amit used objective factors to screen for companies with risk comparable and to identify companies without risk comparable to MERC's. By analyzing the objective measure of such companies' rate of return volatility, Dr. Amit checked the likely risk profiles of the companies that passed his screens when compared to MERC's. The Department noted that this was discussed in its initial brief.

The Department concluded that MERC's proxy group is flawed; therefore, MERC's ROE analyses that rely on that proxy group are not reasonable and must be rejected. The Department stated that, as explained in its Initial Brief at pages 36-37, choosing any unique risk factor, such as size, for MERC while failing to attempt to identify unique risk factors for the companies in the proxy groups is inconsistent, subjective and results in unfair risk comparison.

DCF, CAPM and RP

The Department stated that, to arrive at its recommended ROE, MERC failed to demonstrate the results' reasonableness for each of the three financial models. The Department noted that its Initial Brief includes significant explanation of the many flaws of Mr. Moul's application of his DCF, CAPM and Risk Premium analysis.

The Department noted that the Company's Initial Brief failed to show that its "method" of mixing the results of its inappropriate DCF, CAPM and RP analyses resulted in a reasonable recommended ROE. The Department agreed that use of the DCF method, if properly applied and checked for reasonableness against an also properly applied CAPM, is reasonable to determine ROE; however, MERC committed significant errors in its application of the DCF analysis, as well as in the applications of the DCF, CAPM and RP analyses. MERC's reliance on the three methods resulted in an upwardly biased ROE estimate.

The Department noted practical difficulties with the CAPM that result in the Department using it only as a check on the reasonableness of the DCF analysis and result.

Regarding MERC's Risk Premium analysis, the Department identified specific and serious flaws in Mr. Moul's application of that analysis resulting in upward ROE bias. Based on these flaws, the Department explained that MERC's Risk Premium analysis must be rejected.

MERC's "Risk" Adjustments

The two main risks emphasized by MERC are an upward leverage adjustment to its DCF and CAPM, and an upward size-related adjustment only to its CAPM analysis. The Department noted that it has fully addressed this issue in its Initial Brief. It restated that the principal flaws in the upward adjustment rationale are:

Rather than the macro risk analysis that is required for a reasonable ROE analysis, MERC inappropriately used a micro risk analysis of companies in Mr. Moul's proxy group.

Since MERC's size is only one aspect of the Company's overall financial and business risk, an upward adjustment to ROE due to size is appropriate only if all other investment risk characteristics of a group of companies are the same. It is inappropriate to choose one specific factor of the overall investment risk and use it [to] increase MERC's required rate of return to a level that is higher than the rate of return for the comparison group. Therefore, any "risk premium" associated with a size-only comparison for MERC is inappropriate.

The leverage argument is that there are significant differences between the market debt-to-equity ratio and the book debt-to-equity ratio for the companies in its proxy group such that an upward ROE adjustment for MERC is warranted. The Department restated its arguments including the comment that investors are well aware of the fact that, in recent years, market debt/equity ratios for utilities in Mr. Moul's delivery group have been lower than their book debt/equity ratios. Therefore, the common stock prices of companies in Mr. Moul's Delivery group already reflect any risk associated with the discrepancy between book and market ratios of debt/equity and no additional adjustment is required.

The Department stated that MERC failed to demonstrate the reasonableness of any of its proposed upward adjustments to ROE and, thus, the Company's arguments must be rejected.

Dr. Amit's Recommended ROE of 9.29 Percent

The Company argued that the Department's recommended ROE is so low that it violates the ratemaking principles set forth in the United States Supreme Court's Bluefield and Hope decisions. MERC claimed that any ROE lower than 10 percent "may" jeopardize MERC's ability to attract capital and, therefore, violates the Supreme Court's criteria of reasonableness.

The Department stated that its Initial Brief fully addressed the flaws in MERC's examples of why Dr. Amit's recommended ROE is too low, including:

MERC's incomplete comparisons of recent state utility commission decisions.

The Commission's decisions.

Erroneous reference to Value Line's projected ROEs.

An incorrect argument regarding the Commission's Order in MERC's last rate case, Docket No. G007,001/GR-10-977.

Response to the OAG

The Department claimed that Dr. Amit demonstrated that the ROE recommended by OAG Witness Dr. Chattopadhyay, 8.62 percent, or a figure within his range, 8.60 to 9.1 percent, is unreasonably low and is based primarily on an incorrect assumption that the standard DCF model is biased upward.

The Department stated that its Initial Brief provides a comprehensive discussion of Dr. Chattopadhyay's ROE analysis' many flaws and did not repeat the discussion in the Reply Brief. The Department provided a summary of Dr. Amit's claimed failings of Dr. Chattopadhyay's ROE analyses.

Conclusion

The Department's Recommended ROE of 9.29 percent for MERC is reasonable and appropriate for adoption by the Commission.

OAG

The Office of the Attorney General discussed the cost of capital on pages 20 through 33 of its Initial Brief and pages 16 through 19 of its Reply Briefs.

The OAG argued that MERC's requested return on equity of 10.75 percent is well above the level necessary to balance MERC's and its ratepayers' interests. The OAG claimed that its recommendation relies on a comprehensive analysis and achieves that balance. An ROE of 8.62 percent provides MERC with a reasonable return that is sufficient to attract the capital needed for MERC to fulfill its public functions. The OAG recommended that the Commission reject MERC's excessive request and accept Dr. Chattopadhyay's recommended ROE of 8.62 percent.

OAG ROE Analysis

In determining his recommendation for MERC's ROE, Dr. Chattopadhyay considered the results of two methods rooted in the Discounted Cash Flow construct: the standard single-stage or "constant growth" DCF analysis and the market-to-book method. Additionally, Dr. Chattopadhyay conducted a Capital Asset Pricing Model analysis to inform his range of reasonable ROEs. The OAG argued that, by using several widely accepted economic models, as well as a variety of inputs from respected sources, Dr. Chattopadhyay's analysis captures a broad spectrum of investor behavior and values to establish an appropriate ROE recommendation.

Proxy Group

To develop a proxy with companies similar to MERC, Dr. Chattopadhyay began with the universe of utilities categorized by the Value Line investment service as either gas utilities or gas and electric utilities. In order to ensure that his proxy group was comparable to MERC, Dr. Chattopadhyay eliminated any utility that did not have at least 50 percent of its revenues from its gas distribution business and any utility that did not have at least 75 percent of its assets associated with gas distribution. Dr. Chattopadhyay then applied additional checks related to the S&P credit ratings and dividends. This method resulted in a proxy with investment risks similar to MERC, if not slightly higher. The Companies that met these criteria are:

Company	Ticker
AGL Resources	GAS
Atmos Energy	ATO
Laclede Group, Inc.	LG
Northwest Natural Gas	NWN
Piedmont Natural Gas	PNY
South Jersey Industries Inc.	SJI

The OAG stated that MERC's credit rating and equity ratio are similar to the companies in Dr. Chattopadhyay's proxy. The OAG noted that, compared to the members of the proxy group, Integrys exhibited a similar price-to-earnings ratio, a similar variability of return on equity, superior performance in generating internal funds, superior interest coverage, and a superior operating ratio. Dr. Chattopadhyay cautioned that his proxy contains several companies with substantial non-regulated activities. While these companies present a different risk profile than MERC, to the extent that Dr. Chattopadhyay's proxy does not perfectly reflect the investment risk associated with MERC, it likely does so to MERC's benefit.

Dividend Yield

For the price input in the DCF model, Dr. Chattopadhyay used average daily closing prices for the most recent one-month period ending April 24, 2014. The OAG argued that, while smoothing out daily price movements, using a one-month period provides a reasonable basis to reflect investors' current expectations. For his dividend input, Dr. Chattopadhyay used Value Line's 2014 dividend projections, adjusted upwards to reflect Value Line's expected long-term growth in dividends. The dividend yields ranged from 2.92 percent to 4.32 percent with an average of 3.62 percent.

Growth Rate

To calculate a reasonable growth input in the DCF model, Dr. Chattopadhyay used an average of several published growth metrics. He used earnings growth projections from the Value Line, Yahoo Finance, and Zacks investments services and dividend and book value growth estimates from Value Line. Dr. Chattopadhyay also considered a growth measure based on estimates of the "internal" and "external" growth components. This estimate was calculated by using projected retention ratios and returns for the internal component, projected growth in the number of shares for the external component and current market-to-book ratios.

The OAG claimed that the use of multiple growth metrics to establish the growth component provides several benefits:

> It has been recognized that investors, as a group, do not rely on a single growth metric. Therefore, using an average of several growth metrics better encapsulates investors' collective values than reliance on a single metric.
>
> While the DCF construct assumes that earnings, dividend, and book value all grow at the same rate over the long term; however, since they are limited to periods of three-to-five years, projections by investment services used by analysts show significant differences between these metrics. Therefore, one may reasonably assume that the sustainable long-term growth rate to which earnings, dividends and book value growth rates may converge in the future is represented by their average.
>
> Earnings growth projections tend to be biased upwards when the market-to-book ratio is significantly greater than one, as is the case for MERC. Therefore, Dr.

Chattopadhyay's use of several growth metrics helps correct for this inherent upward bias.

The OAG stated that that Dr. Chattopadhyay's growth estimate is predominantly, but not exclusively, influenced by earnings growth. Earnings growth is assigned more than 80 percent of the weight in Dr. Chattopadhyay's growth estimate, and less than 17 percent of the weight is made up of dividend and book value growth.

DCF Estimates

After performing all of these analytical steps, Dr. Chattopadhyay's DCF analysis developed a range of results from 8.21 percent to 8.89 percent depending on the specific growth projection. To determine his final ROE recommendation, Dr. Chattopadhyay also incorporated the results of his market-to-book and CAPM analyses.

OAG Market-to-Book Analysis

The OAG stated that the market-to-book method utilized by Dr. Chattopadhyay is rooted in the DCF construct, but estimates the cost of equity as the sum of the "internal" return and "external" returns. In other words, to calculate an ROE, rather than using dividend and growth projections from investment analysts, the market-to-book method utilizes projections of investment analysts regarding a company's retention ratio, return on equity, and growth in the number of shares, as well as the company's current market-to-book ratio. Dr. Chattopadhyay's market-to-book analysis resulted in an ROE of 8.69 percent.

OAG CAPM Analysis

For his "risk-free" return, Dr. Chattopadhyay incorporated the current return for the ten-year treasury. Dr. Chattopadhyay noted that a truly risk-free rate would be captured better by using short-term bonds, however, the higher rate of the ten-year Treasury Bond balances the need for a risk-free rate with the fact that utility rates are typically set for periods longer than short-term treasury bills.

Dr. Chattopadhyay developed a forward-looking estimate of the market risk premium by comparing the returns provided by ten-year treasuries to estimates of market return provided by the S&P 500 and Value Line investment service. Dr. Chattopadhyay's CAPM estimate resulted in an ROE of 10.09 percent. This was used to establish the upper-end of his recommended range of reasonable ROEs.

ROE Recommendation

After conducting his analysis, Dr. Chattopadhyay developed a range from 8.6 percent to 9.1 percent with a point estimate of 8.62 percent. The OAG recommended that the Commission approve, an ROE of 8.62 percent.

Comments on the Department's Analysis

The OAG noted that the Department recommended an ROE of 9.29 percent but did not provide a range of reasonable results. It noted that, by relying primarily on the DCF method for his recommendation and using the CAPM method as a "check" on his DCF results, in many ways, DOC witness Dr. Amit's analysis is similar to the analysis conducted by Dr. Chattopadhyay. Dr. Amit also limited his proxy group to companies whose "main line" of business is natural gas distribution and, therefore, present investors with similar investment risk as MERC.

Despite the many similarities between the two analyses, the Department's recommendation is excessive as a result of several important differences. The difference between the OAG and Department final ROE recommendations relates predominately to their positions on two issues. First, Dr. Amit relied exclusively on a single growth metric, earnings growth. Second, Dr. Amit artificially increased his recommended ROE by separately adding floatation costs to the results of his economic models.

Growth Rate

The OAG stated that the Department fails to demonstrate why earnings growth should be the only growth metric used in a DCF analysis. Dr. Amit admits that investors consider factors other than earnings when making investment decisions but then claimed that, rather than incorporating multiple metrics as done by Dr. Chattopadhyay, analysts are somehow required to choose among separate growth metrics to conduct a DCF analysis.

From this premise, Dr. Amit summarized a self-selected sample of financial literature explaining the merits of using earnings growth in the DCF and conducted a technical analysis to demonstrate the statistically strong relationship between earnings growth and a company's price to earnings ratio.

The OAG claimed that Dr. Amit's analysis does not demonstrate that the overall growth component used by Dr. Chattopadhyay leads to an unreasonable result. The OAG claimed that Dr. Chattopadhyay's statistical analysis demonstrated that his overall growth component has a stronger statistical relationship with a company's price-to-earnings ratio than using earnings growth alone. Therefore, Dr. Amit's position that earnings growth is the "best" growth metric for the DCF does not support his conclusion that it should be the only growth metric used. The OAG claimed that Dr. Chattopadhyay's growth component, which uses earnings growth to from 80 percent of its estimate and dividend and book growth for 17 percent of the estimate, provides a superior metric for explaining all investor behavior.

Flotation Cost

The OAG stated that, contrary to Dr. Amit's implication, no authority exists for the proposition that denying an explicit floatation cost adjustment is contradictory to the purpose of rate of return regulation. Rather, the Commission needs to ensure that the ROE it sets is sufficient to fulfill the standards set forth in the Bluefield and Hope cases, while recognizing that flotation costs will be paid by investors when the company issues stock. If the Commission has fulfilled these legal standards without explicitly adjusting the ROE for flotation costs, any additional adjustment for flotation costs is both inappropriately duplicative and unfair to ratepayers.

The OAG stated that each party's ROE recommendation, without an additional floatation cost adjustment, results in a return sufficient for MERC to attract the capital it needs; therefore, the Commission should reject making a duplicative upward adjustment to MERC's ROE.

Comments on MERC's Analysis

The OAG stated that, in contrast with Dr. Chattopadhyay and Dr. Amit, MERC' witness Mr. Moul presents an analysis that attempts to justify the highest possible ROE and lacks any value. As a threshold matter, Mr. Moul suggested that an allowed ROE below 10 percent is de facto unreasonable. This proposition flies in the face of recent trends both nationally and in Minnesota. The Department noted that since 2008, ROEs below 10 percent have become the norm. As Mr. Moul points out, there were eleven rate cases for natural gas utilities decided in the fourth quarter of 2013 in which authorized ROEs ranged from 9.08 percent to 10.25 percent. Of the eleven natural gas rate cases cited by Mr. Moul himself, the highest ROE authorized was fifty basis points below his own recommendation. The OAG noted that the Commission authorized an ROE of 9.59 percent for CenterPoint's Minnesota gas operations only weeks ago.

The OAG stated that Mr. Moul's predisposition to an inflated ROE is demonstrated by his reliance on a series of novel and unreliable analytical approaches. The OAG claimed that, in the current environment, some of these methods produce ROE results that border on the absurd. It noted that the RP method utilized by Mr. Moul produces an ROE of 12.14 percent and his CAPM analysis produced an ROE of 11.97 percent.

The OAG stated that, when they exceed the highest natural gas ROE decision cited by Mr. Moul by well over 150 basis points, the Company's analyses produce results that are not reasonable. The OAG noted that it is unclear from Mr. Moul's analysis exactly how he is blending the results of his various approaches to come to his overall recommendation of 10.75 percent. Mr. Moul's final recommendation is not the median or mean of the results of his various approaches, and he did not provide an equation or other methodology to explain how he derived his final result from the outcomes of his various creative analytical approaches. Mr. Moul's only support for his overall recommendation of 10.75 percent is that it fits well within his range of analytical results. The OAG noted that, when the results of Mr. Moul's analytical methods changed in rebuttal testimony, his final recommendation did not.

The OAG claimed that Mr. Moul's approach is insufficient to support a finding of fact needed for a quasi-judicial determination.

The OAG noted that Moul's DCF estimate is also inflated by use of a variety of unreliable concepts. Mr. Moul's proxy group is not limited to gas utilities, but includes four companies with significant electric operations. Since these companies have a different risk profile than MERC, their addition increased the ROE produced by Mr. Moul's analysis.

Additionally, Mr. Moul proposed a complicated and unnecessary "leverage adjustment" that artificially increases his DCF results. The OAG noted that Dr. Chattopadhyay and Dr. Amit both explained that Mr. Moul's leverage adjustment ignored the fact that utility investors are aware that a utility's earnings are based on an allowed return granted by regulators on the utility's book value. The OAG noted that leverage adjustment has the perverse effect of increasing a return that is already supporting a market price above a company's book value and would result in the detrimental effect of reducing a utility's ROE when the market value of the stock is below the book value and the utility is facing dilution of stock.

OAG ROE Recommendation

The OAG recommended that the Commission approve an ROE of 8.62 percent, or an ROE within the range of 8.6 percent to 9.1 percent.

OAG Reply Brief

Pages 16 through 19.

The OAG stated that MERC's requested return on equity is unreasonable and unsupported by the record. A return on equity greater than the minimum necessary for MERC to attract the capital needed to perform its public functions would result in an inappropriate transfer of wealth from ratepayers to shareholders. The OAG stated that the ROE recommendations by the Department and MERC are excessive because their recommendations are based on flawed analysis.

The OAG stated that its analysis demonstrates that an ROE of 8.62 will allow MERC to attract the required capital.

MERC's Risk Factors

The OAG argued that MERC's suggestion that its investment risk is higher than the companies in each party's proxy group and, due to a few self-selected factors, that its ROE should therefore be higher is not reasonable for multiple reasons.

> First, a company's investment risk cannot be properly evaluated by reviewing a selection of individual risk factors.
>
> Second, even if analysts could review each individual risk factor for every comparable company, the record in this case reflects several risk factors ignored by MERC that would serve to lower MERC's investment risk as compared to the companies in each party's proxy group.
>
> Finally, Minnesota's economic conditions are superior to regions where many of Dr. Chattopadhyay's proxy group's companies operate, which indicates a comparatively lower risk than utilities in other regions.

For these reasons, MERC's suggestion that its ROE should be increased due to a few specific and isolated risk factors is not reasonable and should be rejected.

Reliance on a Single Growth Metric

The OAG stated that multiple growth metrics reflects the reality that investors look at many factors. The Department argued that the DCF method should rely on only a single growth metric, earnings growth. The OAG stated that the Department did not support its position by explaining why investors who consider dividend or book value growth should be ignored or why Dr. Chattopadhyay's overall growth component was flawed. The Department argues that financial literature, economic theory, and econometric analysis support the use of earnings growth.

The OAG noted that the Department suggested that only earnings growth should be used in a DCF analysis because earnings growth forecasts are published by many investment services, whereas only Value Line provides comprehensive long-term dividend growth forecasts. The Department's position of ignoring dividend growth entirely, however, suggests that Value Line is publishing a dividend growth forecast that is not considered by any investors. The fact that Value Line perceives a market for dividend growth forecasts indicates that these forecasts are valuable to some investors and, therefore, should be incorporated into a DCF analysis.

The OAG argued that, because it contemplates the values of different investors, Dr. Chattopadhyay's growth component has a stronger statistical relationship with a company's price-to-earnings ratio than using earnings growth alone. It argued that the Department has failed to demonstrate that, other than earnings growth, it is reasonable to ignore growth metrics such as dividend growth and book value growth. Accordingly, the OAG's growth component is reasonable and should be considered in a proper DCF analysis.

Administrative Law Judge

The ALJ addressed cost of equity issues on pages 13 through 28 of his Report

Discounted Cash Flow

Market to Book Adjustment

In Finding 98 the ALJ found that the DCF model does not produce upwardly biased estimates of the cost of equity capital.

Flotation Cost

In Finding 99 ALJ found that recovery of flotation costs is appropriate because, without such an issuance cost adjustment, MERC may be denied the opportunity to earn its required rate of return.

In Finding 100 the ALJ found that he DCF and TGDCF results are appropriately adjusted by using flotation costs of 3.90 percent.

Comparable Group

In Findings 115 through 117, the ALJ stated that, because of the differing risk profiles, each of the proposed comparison groups has its drawbacks. Mr. Moul's Delivery Group includes four combination electric and natural gas delivery companies with higher risk profiles than MERC. Dr. Amit's NGCG included companies whose risk profiles were lower than MERC's – presumably with easier access to capital. Dr. Chattopadhyay's DCF Proxy Group contained several companies that have substantial non-regulated activities. This grouping thus presents a very different risk profile than MERC.

Growth Rate

In Finding 122 the ALJ stated that because the rates of returns on equity and dividend payouts are oftentimes uneven for a utility, a utility's historical growth rate may be a poor indicator of future performance. To account for this volatility, it is a better practice to project growth rates based upon rises in earnings per share. Genuine, long-run and sustainable growth in dividends is driven by growth in earnings.

Dividend Yield

In Finding 125 the ALJ stated that when undertaking a DCF analysis, selection of the review period for share prices is important. It is the best practice to use a period that is both recent enough to reflect current conditions for the utilities and long enough to avoid short-term, aberrational volatility in prices.

In Finding 131 the ALJ found that Dr. Amit reasonably used the thirty day closing prices to calculate the expected dividend yield, September 1, 2013 through September 30, 2013.

In Finding 132 the ALJ found that Dr. Amit later updated the expected dividend yield for companies in the NGCG by using the then-most recently available thirty-two day period closing prices (between March 14 and April 14, 2014).

Growth Rates and Dividend Yields

In Finding 134 the ALJ noted that MERC's updated dividend yield, with the forward-looking adjustment, is 4.05 percent.

In Finding 141 the ALJ stated that based on Dr. Amit's DCF and TGDCF analyses for the NGCG group, the required rate of return for MERC ranged from a low of 8.61 percent to a high of 10.14 percent, with flotation costs.

In Finding 142 the ALJ noted that Dr. Amit concluded that the most reasonable required rate of return on common equity for MERC inside this range was the mean of 9.40 percent.

In Findings 143 and 144 the ALJ stated that Dr. Chattopadhyay's "traditional" DCF analysis resulted in a recommended ROE of 8.21 percent. His market-to-book analysis resulted in a recommended ROE of 8.69 percent. Dr. Chattopadhyay combined four different DCF analyses to produce his overall recommended ROE of 8.62 percent.

Capital Asset Pricing Model

In Finding 151 the ALJ stated that Mr. Moul upwardly adjusted the CAPM risk measurement to account for the difference between MERC's market-debt/equity ratio and book-debt /equity ratio.

In Finding 152 the ALJ found that, because this difference is already accounted for by investors, no additional adjustment is needed.

In Finding 153 the ALJ stated that Dr. Amit reasonably adjusted Mr. Moul's proposed beta by disregarding Mr. Moul's upward adjustment of the Value Line beta of 0.67.

In Finding 154 the ALJ stated that, likewise, with respect to risk-free rates, Mr. Moul's Blue-Chip's forecast of future yields for thirty-year Treasury Bills as signifying current yields is inappropriate. Because current yields on long-term Treasury bills reflect investors' expectations about the future economic and financial environment, Mr. Moul's use of Blue-Chip's forecast overstates the risk-free rate in the CAPM.

In Findings 155 through 157 the ALJ stated that use of the CAPM raises some difficult issues – including difficulties in determining the appropriate beta and the appropriate riskless asset. The best practice is to compare the results of a DCF and TGDCF analysis against the results produced by other analyses – such as CAPM or the ECAPM. For these reasons, the Department reasonably used the CAPM and ECAPM results as checks upon the reasonableness of its DCF analyses.

In Finding 158 the ALJ stated that application of the CAPM to the NGCG resulted in an estimated ROE that was lower, 9.11 percent, than Dr. Amit's DCF/TGDCF-estimated ROE of 9.40 percent with flotation costs.

In Finding 159 the ALJ found that Dr. Amit's updated CAPM, with flotation costs, was 9.79 percent.

In Finding 160 the ALJ stated that application of the ECAPM analysis resulted in an estimated ROE mean for the NGCG of 9.96 percent, with flotation costs.

In Finding 161 the ALJ stated that the ECAPM's ROE was appreciably higher than Dr. Amit's CAPM's ROE and somewhat close to the mean of his DCF's ROE for the NGCG.

In Finding 162, the ALJ stated that Dr. Amit's CAPM and ECAPM results for the NGCG lie within the range of Dr. Amit's DCF/TGDCF estimated ROEs – specifically between 8.61 percent and 10.14 percent.

Risk Premium Analysis

In Findings 163 and 164 the ALJ noted that MERC's Risk Premium produced an updated ROE of 12.14 percent.

In Finding 165 the ALJ found that Dr. Amit persuasively testified that Mr. Moul's analysis results in an unreasonable "mismatch" of financial instruments. Mr. Moul calculates the differences in returns on large-cap common stocks, minus the return on long-term corporate bonds, which he applies as a risk premium to utility bonds.

In Finding 166 the ALJ found that the appropriate risk premium should be calculated as the difference between the return on common stock of A-rated utility companies and the return on long-term A-rated utility bonds.

Other Key Data Points

In Finding 167 the ALJ stated that the average ROE determinations made by state utility commissions for the eleven natural gas rate cases resolved during the fourth quarter of 2013 was 9.83 percent.

In Finding 168 the ALJ noted that the range of those allowed ROEs extended from a low of 9.08 percent to a high of 10.25 percent.

In Finding 169 the ALJ noted that Dr. Amit's final recommended ROE of 9.29 percent is at the lower end of this range of recent determinations. Mr. Moul's suggested ROE of 10.75 percent is beyond this range. Likewise, Dr. Chattopadhyay's "DCF Construct" ROE of 8.62 percent is beyond this range.

Administrative Law Judge's Recommended Return on Equity

In Finding 170 the ALJ found that, because stock prices fully account for all publicly available information, use of the DCF model does not require later adjustments for the discrepancies between the market and book values of equity and debt.

In Finding 171 the ALJ found that the DCF model is a reasonable, market-oriented approach to determine a fair ROE for MERC.

In Finding 172 the ALJ stated that, because MERC's risk profile is higher than the comparison group used by the Department, in his view, Dr. Amit's recommendation of 9.40 percent understates the appropriate return on equity.

In Finding 173 the ALJ stated that, in his view, the results of Dr. Amit's updated CAPM with flotation costs – namely, a recommended ROE of 9.79 percent – yields a better and more reasonable result. This higher percentage is:

(a) more reflective of the investment risks MERC presents when seeking capital;

(b) one basis point from MERC's updated DCF analysis, which rendered a ROE of 9.8 percent;

(c) supported by Dr. Amit's ECAPM analysis, which resulted in an estimated ROE mean for the NGCG of 9.96 percent, with flotation costs;

(d) comfortably within the overall range for Dr. Amit's DCF and TGDCF analyses (with a low of 8.61 percent to a high of 10.14 percent, including flotation costs); and

(e) close to the average ROE determinations made by state utility commissions for the eleven natural gas rate cases that were resolved during the fourth quarter of 2013 – specifically, an average ROE of 9.83 percent.

In Finding174 the ALJ found that based upon the records in these proceedings, a return on equity for MERC of 9.79 percent is reasonable and appropriate.

Exceptions to the ALJ Report

MERC

MERC supported the ALJ's proposed cost of equity.

Department of Commerce

Pages 2 through 14 of the Department's Exceptions to the ALJ Report.

The Department took exception to the ALJ Report's recommended return on equity of 9.79 percent. It stated that the record does not support the ALJ's finding that MERC's risk profile is higher than that of the Department's comparison group such that an ROE higher than the results of Dr. Amit's Discounted Cash Flow analysis is warranted.

The Department also disagreed with the Report's conclusion that the results of Dr. Amit's updated Capital Asset Pricing Model of 9.79 percent with flotation costs is an appropriate basis for MERC's ROE or yields a better and more reasonable result.

The Department took exception to Proposed Findings 112, 116, 172, 173 and 174.

The Department argued that the key to a reasonable ROE for MERC is reliance on a properly applied DCF method, based on reasonable inputs, together with confirmation of the reasonableness of the DCF analysis by use of a properly applied CAPM analysis. Having checked the reasonableness of his DCF analyses through his application of CAPM, the results of Dr. Amit's DCF analysis of 9.29 percent (with flotation costs) is well-supported in the record as a reasonable ROE for MERC.

As further confirmation of the reasonableness of Dr. Amit's analysis, Dr. Amit's corrections for the flaws in Mr. Moul's analysis yielded an ROE of 9.25 percent (with flotation costs), which is only 4 basis points below Dr. Amit's recommendation of 9.29 percent. The Department's Exceptions restated the practical difficulties in application that eliminated the CAPM as a stand-alone method for determining a reasonable ROE. As a result, to the extent that the ALJ Report relies on Dr. Amit's CAPM analysis, the Report necessarily supports Dr. Amit's DCF-produced ROE of 9.29 percent and not the CAPM result.

The Department's Exceptions also disagreed with the Report's conclusion that MERC is "riskier" than the companies in the Department's comparison group and explained why the conclusion is incorrect.

Exception to Proposed Finding 112

The Department explained its disagreement with Proposed Finding 112 and recommended the following modification:

> 112. Based upon his examination of 2012 common equity ratios and 2012 long-term debt ratios for companies in the NGCG and MERC, and based on Dr. Amit's analysis of all the other risk factors for the companies in the NCGC and for MERC, Dr. Amit concluded that the NGCG and MERC present similar investment risks~~, although "MERC appears to be somewhat riskier than NGCG."~~.

Exception to Proposed Finding 116

The Department stated that ALJ Report Proposed Finding 116 states incorrectly that Dr. Amit's NGCG included companies whose risk profiles were lower than MERC's, with citation to Dr. Amit's Direct and Rebuttal Testimonies. The Department stated that Proposed Finding 116 should read:

> 116. Moreover, as noted above, <u>the companies in</u> Dr. Amit's NGCG <u>have an overall risk profile similar to MERC's</u> ~~included companies whose risk profiles were lower than MERC's presumably with easier access to capital~~.

Exception to Proposed Finding 172

Proposed Finding 172 is incorrect; it builds on the ALJ Report's earlier conclusions that MERC's risk profile is higher than that of the Department's comparison group - conclusions that are corrected by the Department's Exceptions to Proposed Findings 112 and 116.

The Department explained its reasoning and stated that Proposed Finding 172 should read:

> 172. <u>Because MERC's risk profile is similar to the NGCG's risk profile. Dr. Amit's recommendation of 9.29 percent with flotation costs presents an appropriate return on equity.</u> ~~Yet, because MERC's risk profile is higher than the comparison group used by the Department, in the view of the Administrative Law Judge, Dr. Amit's recommendation of 9.10 percent understates the appropriate return on equity.~~

Exception to Proposed Findings 173 and 174

In Proposed Findings 173 and 174 the ALJ Report rejects Dr. Amit's DCF result of 9.29 percent with flotation costs and adopts the result of Dr. Amit's CAPM analysis of 9.79 percent as the recommended ROE for MERC. The Department disagreed with these proposed findings, explained its reasons, and stated that Proposed Finding 173 should be stricken and Proposed Finding 174 should read:

> 174. Based upon the records in these proceedings, the Department's updated DCF ROE result of 9.29 percent with flotation costs (Amit Surrebuttal at 2) ~~a return on equity for MERC of 9.79 percent~~ is the most reasonable and appropriate result for MERC's cost of equity.
>
> [The Department added that Footnote 174 regarding the final capital structure should read: Consistent with the recommended Common Equity and Overall Rate of Return on page12 of Dr. Amit's Surrehuttal Testimony, ~~T~~the resulting recommended capital structure should ~~would~~ be corrected to read:

	Capitalization Ratio	Cost Percentage	Weighted Cost
Long-Term Debt	0.4464	0.055606	0.024823
Short-Term Debt	0.0505	0.023487	0.001186
Common Equity	0.5031	0.0929 ~~0.0979~~	0.046738 ~~0.019253~~
Total:	1	**Rate of Return:**	7.2747% ~~7.5262%~~

> [Ex. 202 at 12 (Amit Surrehuttal) [the Department agrees with the ALJ Report's Long-Term Debt and Short-Term Debt numbers]].

Clarifications and Corrections

The Department stated that clarifications and corrections are needed for Proposed Findings 160-162:

> 160. Application of the ECAPM analysis resulted in an estimated ROE mean for the NGCG of 9.76 ~~9.96~~ percent with flotation costs. [FN: Ex. 200 at 33 (Amit Direct)]
>
> 161. In Dr. Amit's Direct Testimony, ~~T~~the ECAPM's ROE was appreciably higher than Dr. Amit's CAPM's ROE and somewhat close to the mean of his DCF's ROE for the NGCG.
>
> 162. In his Direct Testimony, Dr. Amit's CAPM and ECAPM results for the NGCG lie within the range of Dr. Amit's DCF/TGDCF estimated ROEs - specifically, between 8.61 percent and 10.14 percent.

Office of the Attorney General

Pages 19 through 26 of Exceptions to the ALJ Report.

The OAG disagreed with the ALJ's cost of equity recommendation. It stated that the record in this case supports a return on equity substantially lower than the 9.79 percent recommended by the ALJ. The ALJ's recommendation was not supported by any of the three expert witnesses in this case and is based on an incomplete analysis of the record, a misunderstanding of witness testimony, and an overreliance on several irrelevant facts.

The OAG stated that the ALJ appears to have relied on the proxy group selected by the Department, the DCF analysis conducted by MERC, and the Department's ECAPM and TGDCF analyses. The OAG took exception to these specific findings and argued that its analysis produces the most reasonable ROE for MERC.

The OAG stated that the Findings contain several critical flaws that lead to the ALJ's excessive ROE recommendation. First, while the ALJ correctly concluded that the DCF model is a reasonable, market-oriented approach to determine a fair ROE for MERC, his recommended ROE is not the result of any party's DCF analysis. Rather, the ALJ chose to recommend the result of the Department's CAPM analysis after apparently concluding that Department witness Dr. Amit had not appropriately considered MERC's risk profile when making his recommendation.

Specifically, the ALJ concluded that, because MERC's risk profile is higher than the comparison group used by the Department, the 9.29 percent ROE resulting from the Department's DCF analysis understated the appropriate ROE for MERC.

The OAG argued that the record does not demonstrate that MERC's risk profile is higher than the Department's nor any of the three ROE witnesses' comparison groups in this case. Most importantly, when Dr. Amit considered business and financial risk together, he concluded that MERC's investment risks are reasonably similar to the investment risks of the companies in his comparison group. Accordingly, the ALJ's conclusion that Dr. Amit testified that MERC presented a greater investment risk than its peers is incorrect and led to the ALJ's unreasonable ROE recommendation.

The OAG restated its arguments that several factors, compared to the companies in each party's proxy group, serve to lower MERC's risk. The OAG stated that, other than the non-regulated activities of comparable companies, the ALJ ignored all of these factors from the record, which the ALJ characterized as presenting a very "different" risk profile than MERC.

The OAG stated that, if anything, the record demonstrates that MERC's risk profile is likely lower than the companies included in the parties' proxy groups. For these reasons, the ALJ's decision to ignore the "reasonable, market-oriented approach" of using a DCF analysis because he believed Dr. Amit and other experts failed to consider MERC's supposedly higher risk profile is unreasonable and should be rejected.

Second, the Findings refer to "Other Key Data Points" that the ALJ appears to have considered in making his ROE recommendation of 9.79 percent. Specifically, the Findings note that eleven natural gas rate cases were resolved during the fourth quarter of 2013 and that the average awarded ROE for these cases was 9.83 percent. The range of ROEs awarded to these companies extended from 9.08 percent to 10.25 percent. From this information, the ALJ appears to have concluded that his ROE recommendation of 9.79 percent is reasonable because it is "close to the average" of these eleven ROE determinations.

The OAG argued that the record does not demonstrate that using the average of eleven recent ROE decisions is a suitable alternative to selecting a proxy group of companies with a comparable risk profile and performing a thorough analysis applying sound economic modeling. The record does not demonstrate that the average ROE of several recent rate case decisions can appropriately inform or even provide a "check" on the ROE awarded in this case. Put simply, the record does not demonstrate that these eleven companies are similar to MERC in any way other than that they are also natural gas distribution utilities.

The OAG argued that, since one of these decisions awarded an ROE of 9.08 percent while another awarded an ROE of 10.25 percent, these companies have very different risk profiles from each other. The ALJ's apparent conclusion that MERC's specific risk profile falls near the average of these companies is simply an unsupported guess that is not in the record.

The OAG recommended that the Commission reject the ALJ's ROE recommendation and approve an ROE for MERC consistent with the OAG's previous recommendations in this matter.

The OAG acknowledged that the Department's proposed ROE would be preferable to the ALJ's recommendation and better supported by the record in this case.

The OAG recommended that paragraphs 98, 99, 100, 116, 122, and 172-174 be removed from the Findings, and that other paragraphs be changed as follows:

> 97. On behalf of the OAG-AUD, Dr. Chattopadhyay persuasively explained why ~~asserts that~~ floatation costs should not be separated from MERC's ROE determination. Dr. Chattopadhyay ~~argues~~ explains that the DCF methodology already produces an upwardly biased ROE, in cases such as this, where the market-to-book ratio (M/B ratio) of comparable companies is greater than one. ~~In his view,~~ Inclusion of floatation costs is needed to counter-balance (and not further compound) the effects of the DCF model's upward bias.
>
> 112. Based upon his examination of 2012 common equity ratios and 2012 long-term debt ratios for companies in the NGCG and MERC, Dr. Amit concluded that the NGCG and MERC present similar investment risks. ~~, although "MERC appears to be somewhat riskier than NGCG."~~
>
> 120. In his Surrebuttal Testimony, Dr. Amit ~~reasonably~~ updated the expected growth rate of dividends for companies in the NGCG by using the most recent available projected growth rates of Zacks, Value-Line and Thomson.
>
> 121. Dr. Chattopadhyay, on behalf of the OAG-AUD ~~argued~~ explained that, ~~that~~ because investors consider various factors when they price utility stock, it is reasonable to average expected earnings per share (EPS), dividends per share (DPS) and book value per share (BPS) to reflect investors' expectations of dividend growth rates.

> 123. ~~Likewise, a~~Any inequality, during the short term, in the rates of growth of EPS, DPS and BPS is more appropriately resolved by incorporating each growth metric into an overall growth estimate, as done in Dr. Chattopadhyay's analysis. This methodology also considers the fact that different investors place different values on varying growth metrics. ~~assuming a convergence of these rates over the long-term than it is by an arithmetic averaging of the different rates today.~~

The OAG recommended that the Commission adopt the following paragraph in place of the ALJ's findings 172–174:

> 172. The Commission will approve a Return on Equity of 8.62 percent, as recommended by the OAG. This ROE is within the range of results from the DOCs analysis, takes into account the legitimate needs of the Company to attract capital and remain competitive while also resolving any questions in favor of ratepayers, as required by the legislature and the courts.

Commission Decision Options

Some Commission options regarding the cost of equity are:

Comparable Groups

7. Determine that the companies in the Department's NGCG have similar risks to MERC. (Department)

   If the Commission makes this determination it may want to adopt the Department's and OAG's proposed modified Finding 112 and the Department's proposed modified Finding 172.

   Proposed modified Finding 112:

   > 112. Based upon his examination of 2012 common equity ratios and 2012 long-term debt ratios for companies in the NGCG and MERC, Dr. Amit concluded that the NGCG and MERC present similar investment risks. ~~, although "MERC appears to be somewhat riskier than NGCG."~~

   Department proposed modified Finding 172:

   > 172. Because MERC's risk profile is similar to the NCGC's risk profile. Dr. Amit's recommendation of 9.29 percent with flotation costs presents an appropriate return on equity. ~~Yet, because MERC's risk profile is higher than the comparison group used by the Department, in the view of the Administrative Law Judge, Dr. Amit's recommendation of 9.10 percent understates the appropriate return on equity.~~

8. Determine that the companies in MERC's comparable group have similar risks to MERC. (MERC)

9. Determine that the companies in the OAG's comparable group have similar risks to MERC. (OAG)

   If the Commission makes this determination it may want to strike Finding 116 as recommended by the OAG and adopt the Department's and the OAG's proposed modified Finding 112 as discussed above.

10. Determine that MERC has a higher risk profile than the comparison group used by the Department. (ALJ)

Method for Determining Cost of Equity

11. Determine that the discounted cash flow method, checked for reasonableness, is appropriate for estimating the cost of equity for MERC Energy in this proceeding. (DOC, OAG)

    If the Commission makes this determination it may want to strike ALJ Finding 173 as proposed by the DOC and the OAG.

12. Determine that a combination of methods should be used for estimating the cost of equity for MERC Energy in this proceeding. (MERC)

13. Determine that the results of the CAPM, with flotation costs, yields and better and more reasonable result than the DCF. (ALJ)

14. Make no determination on the specific method for determining the cost of equity.

Growth Rate

15. Determine that the record supports the use of the EPS growth rate as the most appropriate projected growth rate for the DCF analysis in this proceeding. (MERC, DOC, ALJ)

16. Determine that the record supports the use of projected dividend growth, book-value growth, and the earnings growth for the projected growth rate in the DCF analysis in this proceeding. (OAG)

    If the Commission adopts the OAG's position it may want to adopt the OAG's recommendation to strike Finding 122 and adopt its proposed modified Findings 120, 121, and 123 as discussed above.

17. Make no determination regarding the appropriate growth rate (dividend, earnings, or book value) to use in the DCF model.

Dividend Yield

18. Determine that, to avoid irrelevant historical prices and short-term aberrations in the capital market, it is appropriate use recent closing prices, such as 30 days, to calculate the dividend yield for a discounted cash flow analysis in this proceeding. (DOC, OAG, ALJ)

19. Determine that, to avoid irrelevant historical prices and short-term aberrations in the capital market, it is appropriate use an average of the daily closing prices for a six month period to calculate the dividend yield for a discounted cash flow analysis in this proceeding. (MERC)

20. Determine that some other time period is appropriate for calculating the dividend yield to use in a discounted cash flow analysis in this proceeding.

21. Make no determination.

Market to Book Adjustment

22. Determine that the DCF analyses in this proceeding do not result in an upward bias to ROE due to the market-to-book ratio of companies in the NGCG. (MERC, DOC, ALJ)

23. Determine that a DCF analysis applied to companies with market-to-book ratios greater than one results in an upward bias. (OAG)

24. Determine that there is not sufficient evidence in the record to conclude that a market-to-book value greater than one results in an upward bias in a DCF analysis.

25. Make no finding.

Flotation Cost

26. Make no specific determination regarding flotation costs.

27. Determine that the cost of equity should not reflect a flotation cost. (OAG)

    If the Commission decides to not make a specific determination regarding flotation costs, or adopts the OAG's position, it may want to strike Findings 98, 99, and 100 and adopt the OAG's proposed modified Finding 97:

    97. On behalf of the OAG-AUD, Dr. Chattopadhyay persuasively explained why asserts that floatation costs should not be separated from MERC's ROE determination. Dr. Chattopadhyay argues explains that the DCF methodology already produces an upwardly biased ROE, in cases such as this, where the market-to-book ratio (M/B ratio) of comparable companies is greater than one. In his view, Inclusion of floatation costs is needed to counter-balance (and not further compound) the effects of the DCF model's upward bias.

28. Determine that the flotation cost adjustment of 3.9 percent used by the Department and the Company is appropriate. (MERC, DOC, ALJ)

Department Clarifications

29. Adopt one or more the Department's clarifications and corrections for Findings 160 - 162:

    A. 160. Application of the ECAPM analysis resulted in an estimated ROE mean for the NGCG of 9.76 ~~9.96~~ percent with flotation costs. [FN: Ex. 200 at 33 (Amit Direct)]

    B. 161. In Dr. Amit's Direct Testimony, ~~T~~the ECAPM's ROE was appreciably higher than Dr. Amit's CAPM's ROE and somewhat close to the mean of his DCF's ROE for the NGCG.

    C. 162. In his Direct Testimony, Dr. Amit's CAPM and ECAPM results for the NGCG lie within the range of Dr. Amit's DCF/TGDCF estimated ROEs - specifically, between 8.61 percent and 10.14 percent.

30. Take no action on the Department's proposed clarification and corrections.

Cost of Equity

31. Adopt the cost of equity of 10.75 percent as requested by the Company. (MERC)

32. Adopt the Department's recommended cost of equity of 9.29 percent. (DOC)

    If the Commission adopts the Department's recommendation it may want to adopt the Department's recommendation to strike finding 173, and adopt its proposed modified Findings 172 and 174 as discussed above.

33. Adopt the OAG's recommended cost of equity of 8.62 percent. (OAG)

    If the Commission adopts the OAG's recommendation it may also want to adopt the OAG's recommendation to remove ALJ Findings 172 through 174 and replace them with the OAG's proposed modified Finding 172 as discussed above.

34. Adopt the ALJ's recommendation of 9.79.

35. Adopt some other cost of equity the Commission considers appropriate.

Overall Cost of Capital

If the Commission has made specific findings regarding capital and the component costs, it does not need to make a specific finding on the overall cost of capital. However, to avoid possible confusion or questions regarding the Commission's decision, it may want to adopt a specific Rate of Return for this proceeding.

Some Commission options regarding the overall cost of capital are:

36. Take no specific action.

37. Adopt an overall cost of capital of 7.5262 percent as reflected by the ALJ recommendations.

38. Adopt an overall cost of capital of 8.0092 percent as recommended by MERC.

39. Adopt an overall cost of capital of 7.2745 percent as recommended by the Department.

40. Adopt an overall cost of capital of 6.9375 percent, reflecting the OAG's recommended cost of equity.

41. Determine that some other overall cost of capital is appropriate and have the staff calculate the proper value, based on the component parts, for inclusion in the order.

(Note: These decision alternatives correspond to alternatives 112 through 146 on the deliberation outline.)

Sales Forecast

PUC Staff: Clark Kaml

Statement of the Issue

What is the appropriate sales forecast for setting rates?

Introduction

MERC addressed this issue on pages 4 and 5 of its initial brief, pages 12 through 20 in reply brief.

The Department addressed this issue on pages 55 through 64 of its initial brief and pages 14 and 15 of its reply brief.

The OAG did not directly address this issue.

The ALJ addressed this issue in proposed findings 176 through 197 of his Report.

Background

Test-year sales volumes affect both revenues and expenses. Generally, lower sales levels produce higher rates, since costs are spread over fewer units. In designing rates, test-year sales volumes are used to allocate costs in the Class Cost of Service Study, a tool which is then used as a benchmark comparison to establish the revenue apportionment. Additionally, when establishing final rates, the test-year sales volumes are used to a) determine the overall revenue requirement and the individual tariffed rates, and b) calculate the Conservation Cost Recovery Charge. Therefore, sales forecasts are an essential part of the ratemaking process. Because sales levels are an integral input in calculating a utility's rates, the method of determining the sales levels must be reasonable.

Development in this Docket

MERC agreed to use the Department's proposed test year sales. In its Initial Brief MERC explained that it accepted use of the Department's proposed test year sales forecast because the Department's forecast benefitted from a full year of calendar 2013 data that was not available to MERC when the Company prepared its test year sales forecast.

The Department recommended an increase in test-year sales of approximately 26,791,937 therms from the Company's originally filed figure of 662,833,577, for a total of 689,625,514 therms. The Department's recommendation increases total test-year revenue by approximately $8,965,273 from the Company's revenue figure of $257,186,462 to $266,151,735.

The increase sales estimate increases total gas cost from $173,412,060 to $180,411,466, an increase of $6,999,406.

The Department recommended that for future rate cases, the Commission require the Company to provide the following:

> A summary spreadsheet that links together the Company's test-year sales and revenue estimates, its CCOSS, and its rate design schedules;
>
> A spreadsheet that fully links together all raw data, to the most detailed information available and in a format that enables the full replication of MERC's process, that the Company uses to calculate the input data it uses in its test-year sales analysis;
>
> If, in the future, MERC updates, modifies, or changes its billing system, a bridging schedule that fully links together the old and new billing systems and validates that there is no difference between the two billing systems;
>
> Any, and all, data used for its sales forecast 30 days in advance of its next general rate case; and
>
> Detailed information sufficient to allow for replication of any and all Company derived forecast variables.

The Company agreed to these conditions in its previous rate case and has committed to complying with all of the Commission's previous sales forecasting requirements in the Company's future rate cases.

The Department stated that it intends to continue working with MERC on issues such as MERC's Statistically Adjusted End-Use, or SAE rate class sales estimates, ongoing refinement of weather-normalization and potentially other sales forecasting.

Department - Reply Comments

In reply comments the Department stated that the OAG's initial brief misrepresents Ms. Otis' Surrebuttal Testimony. The OAG represented that according to Ms. Otis, the presence of heteroscedasticity in MERC's regression means that MERC results are biased and unreliable.

The Department noted that Ms. Otis stated that heteroscedasticity means that the estimated variances and covariances are biased and inconsistent. It does not affect the value of the regression coefficients.

ALJ

In finding 192 the ALJ stated that MERC accepted the Department's recommended alternative test year sales forecast.

In finding 197 the ALJ concluded that the sales forecast agreed to by MERC and the Department is reasonable and should be used for purposes of setting rates in this proceeding.

Commission Forecast Options

Forecast

Some Commission options regarding the forecast are:

1. Adopt the Department's forecast. (MERC, DOC, ALJ)

2. Adopt some other forecast the Commission thinks is more appropriate.

Future Rate Cases

Some Commission options regarding the forecast in future rate cases are:

3. Adopt some or all of the following Department recommendations and require MERC to, in future rate case filings, include:

   A. A summary spreadsheet that links together the Company's test-year sales and revenue estimates, its CCOSS, and its rate design schedules;

   B. A spreadsheet that fully links together all raw data, to the most detailed information available and in a format that enables the full replication of MERC's process, that the Company uses to calculate the input data it uses in its test-year sales analysis;

   C. If, in the future, MERC updates, modifies, or changes its billing system, a bridging schedule that fully links together the old and new billing systems and validates that there is no difference between the two billing systems;

   D. Any, and all, data used for its sales forecast 30 days in advance of its next general rate case; and

   E. Detailed information sufficient to allow for replication of any and all Company derived forecast variables.

4. Add any other requirements the Commission considers appropriate.

(Note: These decision alternatives correspond to alternatives 147 through 150 on the deliberation outline.)

Class Cost of Service Study

PUC Staff: Clark Kaml

Statement of the Issues

Should the Commission:

- Adopt MERC's proposed CCOSS as the starting point in designing rates?
- Modify MERC's proposed CCOSS?
- Adopt the OAG's CCOSS?

Introduction

MERC addressed these issues on pages 75 through 87 of its Initial Brief and pages 44 through 63 of its Reply Brief.

The Department discussed these issues on pages 135 through 150 of its Initial Brief. It did not address the CCOSS in its Reply Brief or Exceptions to the ALJ Report.

The OAG discussed these issues on pages 33 through 57 of its Initial Brief, pages 1 through 8 of its Reply Brief, and pages 2 through 8 of its Exceptions to the ALJ Report.

The ALJ covered the Class Cost of Service issues on pages 91 through 96 of his Report.

Background

As required by Minn. Rules, Part 7825.4300, MERC's application included a class cost of service study. The Commission's rule regarding the preparation of the CCOSS is general and does not specify how the Commission is to use the study. Historically, the Commission has often accepted a company's CCOSS, sometimes with modifications suggested by other parties, and considers it, along with other factors, to set rates. In its May 4, 2009 Order in a Minnesota Power rate case (Docket No. E-001/GR-08-415), the Commission explained:

> Other factors include, inter alia, economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; and ability to bear, deflect, or otherwise compensate for additional costs. (Commission Order at 63.)

As discussed by the parties, the purpose of a CCOSS is to identify, as accurately as possible, the responsibility of each customer class for each cost incurred by the utility in providing service. A CCOSS should reflect cost causality, meaning that the customer(s) who impose a cost on the system should be assigned that cost. The CCOSS can then be used as a factor in determining how costs should be recovered from customer classes through rate design.

According to the January 1992 *Electric Utility Cost Allocation Manual of the National Association of Regulatory Utility Commissioners* (Electric Manual), there are three steps in performing a CCOSS. First, costs are functionalized, or grouped according to their purpose. Second, costs are classified based on how they are incurred. Third, costs are allocated to the various customer classes.

Costs are typically functionalized by the Uniform System of Accounts as provided by the Federal Energy Regulatory Commission (FERC). These accounts group costs into their various functions, such as production (e.g., costs associated with power generation and wholesale purchases), transmission (e.g., assets and expenses associated with the high voltage system) and distribution.

The functionalized costs are classified as "customer," "demand," and "energy" costs according to how they are incurred. "Customer" costs, such as metering costs, billing tracking accounts and responding to customer questions, are those operating and capital costs that vary with the number of customers regardless of the customers' energy consumption. "Demand" costs, such as distribution system size, are those incurred to serve system peak demand and are not affected by the number of customers to be served. "Energy" costs, such as fuel, are those that vary with the quantity of energy produced.

The functionalized and classified costs are usually allocated to customer classes as follows:

- Customer-related costs are allocated among the customer classes based on the number of customers, typically weighted to reflect, for example, differences in metering costs among customer classes;

- Demand-related costs are allocated among the customer classes based on the demand imposed by the class on the system during specific peak hours; and

- Energy-related costs are allocated among the customer classes based on the energy that the system supplies to serve the various customer classes.

Party Positions

MERC

Background

The CCOSS prepared by MERC is a fully allocated, embedded cost of service study similar to the one filed in MERC's 2010 rate case. MERC claimed that, to the extent possible, the assignment of values to rate schedules was done as recommended by the American Gas Association (AGA) in its Fourth Edition of Gas Rate Fundamentals (1987) and the National Association of Regulatory Utility Commissioners (NARUC) in their Gas Distribution Rate Design Manual (1989).

The Company's CCOSS allocated revenue deficiency by customer class, as set forth in the testimony and exhibits of Ms. Hoffman Malueg.

MERC noted that the Department recommended that the Commission:

> Accept MERC's CCOSS as a useful tool for the purpose of setting rates.
>
> In the proposed CCOSS, approve MERC's allocation of income taxes on the basis of the taxable income attributable to each customer class that fully and only reflects the cost of providing service.
>
> Reject OAG recommendation that the Commission order MERC to classify 30 percent of the Mains account as customer costs and 70 percent as capacity costs.

Income Tax Allocation

The Commission's June 29, 2009 Order in Docket No. G-007,011/GR-08-835 required that MERC's future CCOSS's allocate income taxes on the basis of taxable income attributable to each customer class. MERC noted that the Department verified that MERC's proposed allocation of income taxes by class, on the basis the CCOSS, results in an allocation identical to a rate base allocation. MERC noted that it used the same approach in its 2010 rate case, Docket No. G007,011/GR-10-977. MERC claimed that this approach is the only reasonable approach for the allocation of income taxes and is consistent with Commission precedent. MERC added that the Commission should require that, in future rate cases, MERC allocate income tax by class on the basis of taxable income that reflects the CCOSS.

MERC noted that the OAG was the only party to object to MERC's proposed income tax allocation. The OAG argued that income taxes should be allocated within the CCOSS in the same manner that MERC calculates total income taxes for the Minnesota Jurisdiction. MERC noted that the OAG claimed that allocating income taxes by class reflecting the CCOSS means that revenues are not considered when determining taxable income because the CCOSS only allocates costs.

MERC claimed that its allocation of income taxes to customer classes within the CCOSS is consistent with past Commission decisions. MERC stated that transcripts of the Commission's deliberations in MERC's last rate case indicated that the Commission concluded that taking a position on this issue was unnecessary. This conclusion was incorporated into the final rate case Order in MERC's last rate case with the Commission taking no action on the CCOSS methodology proposal agreed to by MERC and the Department. The Commission's decision to take no action on the appropriate approach for allocating income taxes in future CCOSS does not equate to a Commission finding that MERC be required to treat income taxes in a specified way in all future CCOSS.

MERC noted that it and the Department agreed that, in future rate cases, MERC should allocate income taxes by class on the basis of taxable income that fully reflects the CCOSS only.

Allocation to Customer and Demand Cost

MERC stated that calculating the cost of service involves a degree of subjectivity and, as a result, there is no single correct CCOSS for a utility. Based on its CCOSS, the Company determined that 68.3 percent of its distribution mains should be classified as customer costs and 31.7 percent should be classified as demand costs.

At the Department's request, MERC conducted additional analysis to corroborate the Company's initial distribution main classification data. Based on the additional analysis, the Department accepted MERC's proposed classification of distribution mains.

In response to OAG criticisms of its zero-intercept study MERC stated:

> MERC does not need to account for more variables in its zero-intercept study.
>
> Requiring MERC to maintain project level data is inefficient, unsupportable, and cannot be cost justified.
>
> The aggregation and averaging of MERC's data produces the most accurate representation of MERC's entire distribution mains system.
>
> MERC's zero-intercept analysis is the proper tool to determine the classification of MERC's distribution mains.

<u>Additional Variables</u>

MERC claimed that the OAG incorrectly argued that MERC needs to collect data on additional variables to improve the Company's zero-intercept analysis. Many of the variables recommended by the OAG are already included in the Company's zero-intercept analysis. Any missing variables were omitted due to limited data availability. Although MERC may be able to retrieve additional distribution main information, significant financial and personnel resources would be required for the Company to gather this information. Additionally, paper documentation is unlikely to provide a complete picture of all of MERC's distribution installations. Consistent with this reality, the OAG knowledged that the zero-intercept study may include any number of "reasonable" variables and the variables that are ultimately included in the analysis are subject to availability.

<u>Maintaining Project Level Data</u>

MERC objected to the OAG's recommendation that it be required to maintain project level data. MERC claimed that this is a higher standard than that for other Minnesota utilities. It noted that OAG identified only one Minnesota utility, CenterPoint Energy, that collects the type of data the OAG considers to be project level data.

MERC stated that the OAG's recommendation that MERC maintain project level data also fails for practical reasons. First, gathering MERC's historical distribution main data would be time intensive and costly, requiring personnel to physically review MERC's paper documentation, both on an initial and an ongoing basis. Second, once gathered, it would take a substantial outlay of MERC's financial and personnel resources to input and process the data; a task that could only be accomplished through the purchase and maintenance of costly information technology assets. Most importantly, maintaining data at the project level simply for use in periodic rate case zero-intercept studies is not a cost that MERC can, or should be required to, justify to its customers.

Aggregation and Averaging of Data

MERC argued that the aggregation and averaging of MERC's data produces the most accurate representation of MERC's entire distribution mains system. The OAG's argument that aggregating or averaging data renders a zero-intercept analysis invalid is inaccurate and improper in MERC's case. Equally inaccurate and improper is the OAG's recommendation that MERC avoid aggregating or averaging data as a way to improve the company's zero-intercept study.

The purpose of the zero-intercept study is to provide a hypothetical zero-load or zero-sized distribution main on MERC's entire system. MERC uses the end result of this analysis to classify distribution mains as an entire system, separating the distribution mains between the classifications of customer and demand.

MERC stated that its approach is supported by both the NARUC Electric Manual and the NARUC gas Distribution Rate Design manual. The NARUC Electric Manual identifies the data necessary to perform a zero-intercept analysis on various electric assets and states that average installed book cost should be utilized. Gas utilities commonly consult the NARUC Electric Manual for guidance on cost allocation and there is no reason that gas utilities could not follow the NARUC Electric Manual's methodologies for performing a zero-intercept study on gas distribution assets. Both manuals state that the minimum-size and zero-intercept analyses will have similar results and that a minimum size analysis utilizes the average cost of data.

MERC noted that page 11 of OAG witness Mr. Nelson's testimony states that the minimum sized main method simply uses the average unit cost of the smallest main. Therefore, it only makes sense that, if conducted properly, in order for a minimum size analysis and a zero-intercept analysis to have comparable results, both must utilize average unit costs.

Zero-Intercept

MERC argued that its zero-intercept analysis is the proper tool to determine the classification of its distribution mains. It noted that the OAG relied on what it calls a "superior" zero-intercept study in this rate case proceeding and zero-intercept analyses completed in other jurisdictions. Based on these analyses, the OAG concluded that 30 percent of MERC's distribution main costs should be allocated to customers, and 70 percent should be allocated to demand. MERC claimed that the OAG's conclusion is misguided for several reasons:

> It is inappropriate to conduct the zero-intercept analysis, or a minimum size analysis, without considering MERC's current minimum installation practices. It appears that the OAG did not give any consideration to MERC's actual installation practices. In order for MERC's minimum system study to be applicable, it must provide an accurate cost causation picture of MERC's current customers. The minimum system analysis is used in the CCOSS

> as a means to set current rates. Thus, absent information regarding MERC's current installation practices, MERC's rates will not be based on the Company's current practices.
>
> The negative values in Exhibit REN-13 of Mr. Nelson's Direct Testimony demonstrate that the results of his zero-intercept analysis are not appropriate. There are fixed and variable costs associated with both plastic and steel distribution mains and to have a negative coefficient of the size-squared variable is equivalent to stating that there is a negative-sized pipe diameter.
>
> Mr. Nelson's complete exclusion of steel distribution mains from the minimum system study ignores MERC's actual installation practices. Steel mains can be, and are, as much a minimum installation requirement as plastic.

MERC argued that the zero-intercept analyses conducted in other jurisdictions are not a sound basis for the OAG's recommended change to MERC's distribution main classification percentages. MERC has a distinct service territory comprised of unique customers and their associated demands, as well as unique geographic terrain and distribution system requirements. In addition to differences in individual systems, other jurisdictions may have different state regulations or utilize different processes when conducting minimum system studies. Thus, absent assurances of an apples-to-apples comparison, reliance on such analyses would be unsupportable.

MERC noted that its first two minimum size studies produced similar results and corroborated the 68.3 percent customer and 31.7 percent demand distribution main classifications. A third study that did not consider MERC's minimum installation standard of a 2" distribution main was also conducted. This change produced results that are similar to the recommendations made by the OAG which. MERC claimed that this result illustrated the extreme and improper results that can occur when utility-specific minimum installation standards are not considered.

MERC noted that the Department did not recommend any changes in MERC's proposed classification of distribution mains.

Customer Records and Collection (FERC Account 903)

MERC noted that the OAG advocated allocating Account 903 using a weighted customer allocator based on the average cost per customer for meters in each rate schedule. MERC argued that the costs in Account 903 are not costs associated with meters. They are costs associated with labor, materials, and expenses related to working on customer applications, contracts, orders, credit investigations, billing, collection, and complaints. Thus, a weighted customer allocator based on the average cost per customer for meters results in an inaccurate cost causation allocation that has no correlation to the actual costs associated with Account 903.

MERC stated that it recognizes that transportation customers require more account administration and should be allocated more Account 903 costs than a sales customer. MERC addresses this issue by removing the program's administration costs from the account. The remaining costs in Account 903 are primarily related to MERC's employment of its third party external service provider, Vertex. Since there are no significant costs differences amongst

MERC's customer classes for the Vertex costs, MERC bases its CCOSS allocation on customer counts. The OAG's argument that other utilities factor in class complexity when allocating Account 903 lacks merit for the simple reason that there is no complexity in the way that MERC is assessed costs by Vertex.

In response to the OAG's argument that the NARUC gas manual recommends using a weighted customer allocator for Account 903, MERC argued that the manual is inapplicable in this rate case. MERC stated that, while it is a good tool for guidance on cost of service allocations, the NARUC gas manual was created in 1989 when utilities did not outsource their customer service functions and is unsuitable for a utility that does not perform its own customer information systems and services function.

MERC Reply Brief

Pages 44 through 63 of MERC's Reply Brief.

MERC's Reply Brief repeats many of its arguments from its Initial Brief.

Classification of Distribution Mains

MERC noted that OAG acknowledges that the CCOSS is a highly subjective tool. The OAG stated "the Commission has previously recognized that cost of service studies 'cannot establish precise values,' because they 'require considerable judgment and employ certain assumptions that might affect the results.'" MERC argued that it is for the ALJ and the Commission to determine whether MERC's CCOSS is reasonable.

MERC argued that it satisfied the technical requirements of the zero-intercept study in three ways:

> In its regression analysis, MERC utilized data similar to that used by other Integrys subsidiaries in their zero-intercept studies; the same specifications and data parameters.
>
> MERC addressed the OAG's technical concerns by responding to OAG Information Requests 700, 702, 704, and 711.
>
> MERC addressed the OAG's technical concerns by performing multiple minimum-size studies. As discussed in MERC's Initial Brief, the studies produced results similar to MERC's zero-intercept study.

MERC claimed that the OAG, by stating in its Initial Brief that the presence "heteroskedasticity means that MERC's regression is totally unreliable". mischaracterized Department witness Ms. Laura Otis' and MERC witness Mr. Harry John's opinions. MERC claimed that Mr. John stated that the presence of heteroskedasticity does not cause the OLS regression to become biased, nor does it cause the coefficient estimates produced within a regression analysis to be biased.

MERC stated that it conducted best fit plots, which confirmed the fit of the regression equation produced from the Company's zero intercept model.

MERC argued that the OAG placed improper emphasis on its stem and leaf plot analysis, alleging that MERC's data set consists of 30 percent outliers. As detailed in MERC's responses to OAG Information Requests 700, 703, 704, and 707, Ms. Joylyn Hoffman Malueg looked for outliers when she initially conducted MERC's zero-intercept study. She did not find 30 percent of the data to be outliers. MERC's zero-intercept regression analysis is technically accurate and supports MERC's distribution main classifications.

Omitted Variable Bias

Since many of the OAG recommended variables are already included in the Company's zero-intercept analysis, MERC argued that its regression model is correctly specified and does not suffer from omitted variable bias. Variables not included were omitted due to limited data availability. This is particularly true given that 85 percent of MERC's distribution mains have installation dates prior to 2006.

MERC claimed that the OAG's attempts to discredit MERC's zero-intercept study on the basis of omitted variable bias are baseless. OAG witness Mr. Nelson failed to determine whether the utilities he compared to MERC used all of the variables he argued MERC should have used in the Company's zero-intercept analysis. The OAG's variables are simply suggested variables. The OAG confirmed that not every one of Mr. Nelson's suggested variables needs to be in the zero-intercept model.

MERC stated that the OAG incorrectly argued that MERC assumed that only the diameter of the main squared impacts the cost of distribution. MERC's regression analysis evaluated not only the diameter of the main squared, but also the Handy-Whitman Escalated Cost (UHWICOST) variable and a weighted form of the quantity variable. In its Initial Brief, the OAG asserted that MERC's own authority and witnesses indicated that construction costs and contractors' bids affect cost and should have been included in MERC's model; however, it did not cite any authority to substantiate this statement.

MERC stated that of its witnesses, only Ms. Hoffman Malueg testified regarding the zero-intercept study and the variables utilized in its zero-intercept analysis. While other MERC witnesses provided testimony regarding main costs, they did not testify regarding the use of main costs within a zero-intercept study or their inclusion in the CCOSS. MERC's zero-intercept model does include the proper variables and, for items that are not specified as unique variables, those items are still included within the model in book costs. MERC claimed that the OAG mischaracterized Ms. Hoffman Malueg's testimony on this subject.

Regarding fittings' and valves' costs, Ms. Hoffman Malueg's Rebuttal Testimony states that the number of fittings and valves are not tracked by MERC on a historical basis. Any costs of fittings or valves are already included in the book costs MERC utilized in its zero-intercept study. MERC never analyzed the costs attributable to fittings or valves such that the Company could say with any certainty whether they have an effect on the cost of MERC's distribution mains. MERC performed its zero-intercept study based on available, complete, and pertinent data.

Data Manipulation

MERC disagreed with the OAG's claim that MERC's data has been manipulated and, therefore, produces an unreliable result. It argued that the aggregation and averaging of MERC's data produces the most accurate representation of MERC's entire distribution mains system.

MERC stated that the OAG's assertions that MERC's data set is "meaningless" and aggregation can "destroy the relationship that a regression is attempting to model," are supported by nothing more than Mr. Nelson's opinion and are baseless. It noted that the OAG failed to mention that MERC, to arrive at the current cost of all distribution main assets, utilized the Handy-Whitman Index (HWI) that converts all book costs, which vary by year of installation, to "current costs". HWI translating book costs into current costs removes any bias or irregularities that could potentially be brought into the regression analysis attributable to the year of installation.

MERC argued that it did not manipulate the data for unit cost through the use of averaging, as claimed by the OAG. MERC claimed that it has demonstrated that it did not predetermine a relationship between the size of the main and the unit cost.

Project Level Data

MERC restated its arguments that it should not be required to maintain project level data and requested that the Commission not require it to maintain this data for the purposes of its zero-intercept study.

Minimum System Study

MERC restated its arguments that the results of its zero-intercept study are supported by its minimum system study. MERC noted that, based on the dramatic difference between OAG witness Mr. Nelson's Distribution Main classification recommendation (30% of Distribution Mains to be classified as customer cost) and MERC's proposed Distribution Main classification (68% of Distribution Mains to be classified as customer cost), and given the OAG's assertions regarding the reliability of MERC's zero-intercept method, the Department requested that MERC classify the Company's Distribution Mains costs using the minimum-size method as contemplated in the NARUC Gas Manual. MERC noted that the Department explained:

> While serving the same purpose as the zero-intercept method, the minimum-size method has the added advantage that it does not rely on regression analysis. In the most recently decided general rate case by the Commission (Docket No. 13-316), even Mr. Nelson believed that one should verify the results of a costs study under [the] zero-intercept method with the results of a costs study under the minimum-size method because it is difficult to calculate the exact costs of a zero diameter main.

MERC has demonstrated that to accurately portray the cost causation of the Company's current customers, MERC must use a 2 inch pipe in its minimum-size study to reflect MERC's current installation standards. A zero-inch pipe does not exist and is purely theoretical in nature. One-inch, two-inch, three-inch pipes, and sometimes even larger sizes, are what are actually used in in MERC's distribution system today, with the majority of MERC's distribution mains being 2-

inches in size. Thus, using anything less than a 2 inch pipe in MERC's minimum-size study would be inaccurate and improper.

MERC stated that the OAG's complete exclusion of steel distribution mains from the minimum system study ignores MERC's actual installation practices. Steel mains can be just as much a minimum installation requirement as plastic. Because there are fixed and variable costs associated with both plastic and steel distribution mains, the exclusion of these mains from MERC's minimum system study would result in an inaccurate cost causation picture of MERC's current customers, which would result in improper customer rates.

The results of MERC's minimum size study support its zero-intercept analysis, which is detailed in MERC's response to the Department's Information Request 725, and demonstrates, that under a minimum-size study using 2 inch pipes, at least 73 percent of MERC's distribution mains would be classified as customer costs.

MERC noted that the Department points out that "[i]n the end, an analyst needs to consider whether the pipe size under the minimum-size method should be based upon the minimum-size equipment currently installed, historically installed, or the minimum size necessary to meet safety regulations. It is a judgment call."

The MERC argued that it has provided ample support to demonstrate that the use of a 2 inch main is reasonable. It noted that the Department agreed and recommended that the Commission accept MERC's classification of Distribution Main costs and reject the OAG's classification of Distribution Main costs.

The OAG's Zero-Intercept Study

MERC argued that the OAG's zero-intercept study is flawed and must be rejected. MERC stated that it provided the OAG with the raw data, which was not manipulated in any way and was taken directly from MERC's accounting system, used in MERC's regression analysis. If MERC's accounting data and regression analyses suffered from the inefficiencies that the OAG claims, then the OAG should have been able to conduct the statistical testing and processes referenced in Mr. Nelson's Direct and Rebuttal Testimonies and perform what the OAG and Mr. Nelson considered a more efficient regression analysis. They did not do so.

The OAG did a regression analysis that produced a negative zero-intercept, or negative zero-sized pipe value. However, there are fixed and variable costs associated with both plastic and steel distribution mains and to have a negative coefficient of the size-squared variable is equivalent to stating that there is a negative-sized pipe diameter. MERC argued that this demonstrates that the results of the OAG's zero-intercept analysis are not appropriate.

MERC claimed that in Docket No. G-008/GR-13-316 Mr. Nelson advocated that the zero-intercept analysis should be cross-checked with a minimum-size analysis. However, he ignored his own advice and improperly cross-checked the reasonableness of his zero-intercept results by comparing them to the results of zero-intercept studies conducted by other utilizes across the nation. At the Evidentiary Hearing Mr. Nelson admitted that he did not conduct any research regarding the specific steps the utilities in his review used to conduct their zero-intercept studies;

therefore, he cannot confirm that those utilities determine their distribution main classifications in a manner similar to MERC.

The Department and MERC rejected the OAG's analysis because it is inappropriate. MERC's third minimum-size study, which most closely approximates the results of the OAG's zero-intercept study, does not take into consideration the Company's minimum installation standards and was provided by MERC to show the extreme results that occur when current minimum installation practices are not considered. The fact that the OAG's zero-intercept study produces results that are similar to MERC's third minimum-size study discredits the OAG's zero-intercept analysis and demonstrates that it is inappropriate for determining mains distribution in the current rate case.

MERC requested that the Commission approve MERC's Distribution Mains account classification of 68.3 percent customer costs and 31.7 percent capacity costs.

Customer Records and Collection Expenses (FERC Account 903)

MERC stated that the only significant cost differences between MERC's customer classes related to FERC Account 903 are the costs from administering MERC's transportation program. MERC recognizes that transportation customers require more account administration and should be allocated more Account 903 costs than a sales customer. MERC accomplishes this by segregating the costs from administering MERC's transportation program from Account 903, and allocating those segregated costs to MERC's transportation customers within the CCOSS.

The OAG's argument that other utilities factor in class complexity when allocating Account 903 lacks merit for the simple reason that there is no complexity in the way that MERC is assessed costs by Vertex. The treatment of these expenses by other natural gas companies in Minnesota is inapplicable to MERC.

MERC claimed that OAG witness Mr. Nelson claims that he is aware that CenterPoint and Xcel outsource their customer service because Ms. Hoffman Malueg stated this in her Rebuttal Testimony. However, nowhere in any of Ms. Hoffman Malueg's testimony does she make such a statement.

Cost of Service Study

MERC stated that the OAG's reference in its Initial Brief to a customer service study conducted by Xcel is unpersuasive in this case. The Xcel study shows that interruptible customers' cost of administering customer service is 20 times larger than residential, and yet those interruptible customers are only allocated 1.89 percent of total customer service costs (whereas residential is allocated 69.75 percent of costs). This confirms that even when a weighting factor is incorporated for large customers, they still comprise a very small amount of the total customer service costs. Addressing the OAG's comment that MERC's method assigns approximately 12 percent more costs to the residential customers, MERC stated that Account 903 makes up 2.7 percent of MERC's Total Operating Expenses for test year 2014, and a 12 percent cost shift would be approximately $800,000, or 0.32 percent of Total Operating Expenses for test year 2014.

The benefits of conducting such a large, time and resource intensive study are diminished by the minimal impact on customer service costs. MERC argued that the OAG concedes that it is up to the ALJ and the Commission to determine how much weight to place on the CCOSS. Thus, MERC should not be required to cost-justify such a study to its customers when the study identifies marginal differences in cost. MERC notes that performing such an intensive study would be made even more difficult by the fact that MERC would need to examine Vertex's records and procedures to formulate any type of study as to how Vertex administers MERC's customer service function.

Weighted Allocator

MERC argued that the OAG, in its Initial Brief, engaged in speculation, arguing that Ms. Hoffman "misses the point" of the OAG's weighted allocator argument because she does not address a hypothetical scenario created by Mr. Nelson where Vertex, by pricing all customers equally, may have spread the increased cost of serving large commercial customers across the residential customers. However, Mr. Nelson has provided no evidence that Vertex has spread the increased cost of serving "imaginary" large commercial customers across the "imaginary" residential customers as set forth in his hypothetical scenario. MERC claimed that it is just as likely that it costs Vertex more to serve MERC's residential customers, and MERC's large commercial customers subsidize such costs.

MERC has entered into an arms-length transaction with a third party vendor to provide a defined set of services. MERC has determined that the Vertex contract is reasonable and there are no significant costs differences amongst MERC's customer classes for the Vertex costs. Thus, a weighted allocator is not appropriate for MERC.

Requiring MERC to use the weighted meters customer allocator for FERC Account 381 is nonsensical because the costs in Account 903 are not costs associated with meters. They are costs associated with labor, materials, and expenses related to working on customer applications, contracts, orders, credit investigations, billing, collection, and complaints. Thus, a weighted customer allocator that is based on the average cost per customer for meters results in an inaccurate cost causation allocation that has no correlation to the actual costs associated with Account 903.

MERC claimed it would be neither desirable, nor appropriate, for the Commission to determine the reasonableness of MERC's allocation of Account 903 costs based on the OAG's speculative and unsubstantiated analysis. Where customer cost differs, MERC has appropriately accounted for those differences.

MERC noted that the Department agrees with MERC's allocation of costs in Account 903. Therefore, the Commission should find MERC's allocation of Account 903 costs reasonable.

Income Tax Allocation in the CCOSS

Addressing the treatment of income tax allocation in the CCOSS, MERC's Reply Brief restates many of the arguments made in its Initial Brief.

MERC claimed that, in an effort to discredit MERC's allocation of income taxes in the current rate case, the OAG's Initial Brief attempts to indicate that MERC deliberately failed to comply with prior Commission orders and instructions and, to allocate income taxes only on the basis of rate base, "selectively" ignores the expenses within the CCOSS.

MERC restated that the May 22, 2012 and May 24, 2012 transcripts of the Commission's deliberations in MERC's last rate case indicated that the Commission concluded that it was unnecessary to take a position on this issue. The OAG's argument in its Initial Brief that "MERC claims that it was unable to allocate income taxes based fully and only on the CCOSS" misstates MERC's testimony.

MERC claimed that Mr. Lindell confuses the terms "net taxable income" with "taxable income that fully and only reflects the CCOSS." In her Rebuttal Testimony, Ms. Hoffman Malueg explains in clear detail the two terms, their meanings, and why there is a significant distinction between them. Similarly, the OAG incorrectly states in its Initial Brief that "MERC is unable to allocate income taxes based fully and only on the CCOSS because of a circular reference problem."

MERC is able to allocate income taxes on the basis of taxable income that fully and only reflects the CCOSS by mathematically proving that it is equal to a proportion of rate base; therefore, it utilizes the rate base method to allocate income taxes in the CCOSS.

MERC noted that the Department also determined that the OAG's arguments are erroneous. The Department's review of the formulas used by MERC to calculate income taxes led the Department to conclude that MERC's calculated income taxes are not only mathematically equivalent to a fixed proportion of the rate base, but that the allocation using the rate base method produces a tax rate across customer classes that is the same tax rate that is applied to MERC's Minnesota jurisdiction.

The Department concluded that, in the current rate case, MERC's proposed allocation of income taxes by class is reasonable because MERC showed that the Company allocated income taxes by class on the basis of taxable income that fully and only reflects the CCOSS. Moreover, the Department determined that MERC's proposed classification and allocation of the functionalized accounts is generally consistent with NARUC Gas Manual and cost-causation principles and MERC made the relevant updates to its input data. MERC requested that the Commission accept MERC's proposed CCOSS as a useful tool for the purpose of setting rates.

Allocation of Meter Reading Expenses FERC Account 902

MERC stated that it addressed FERC Account 902 only to provide clarification in the record on this matter. The Department and MERC agreed on MERC's allocation of Account 902: Meter Reading Expense. The OAG and MERC initially disagreed regarding the allocation of Account

902. However, the OAG later rescinded its objection to MERC's allocation methodology. Therefore, the Commission should approve MERC's proposed allocation of this Account.

Department

Analysis of MERC's Proposed CCOSS

The Department examined MERC's foundations for its proposed cost allocations and is satisfied that the studies MERC used to produce the inputs used in its proposed CCOSS are reasonable and are based upon reasonably current data. The Company provided the Department with a list and short description of all such studies, which were based on current data at the time of the rate case filing (less than three years old).

The Department noted that the Commission's June 29, 2009 Order in Docket No. G-007,011/GR-08-835 required that MERC's future CCOSSs allocate income taxes on the basis of taxable income attributable to each customer class. The Department stated that it was able to verify that allocating income taxes by class on the basis of taxable income that fully and only reflects the CCOSS results in an allocation identical to a rate base allocation under MERC's current circumstances.

The Department concluded that, under current circumstances, MERC's proposed allocation of income taxes by class is reasonable. The Department stated that MERC's proposed classification and allocation of the functionalized accounts are generally consistent with Gas Manual and cost-causation principles and MERC demonstrated that it made the relevant updates to its input data. The Department recommended that the Commission accept MERC's proposed CCOSS as a useful tool for the purpose of setting rates.

Tax Allocation

The Department noted that OAG witness Mr. Lindell disagreed with MERC's recommended CCOSS on the basis of a belief that it allocates income taxes based on each class's share of rate base, not on the share of taxable income attributed to each customer class as the Commission has ordered. Mr. Lindell recommended that the "allocation of income taxes to customer classes be based on taxable income for each class."

The Department concluded that MERC's proposed CCOSS, which appears to allocate income taxes by class on the basis of rate base, is reasonable under MERC's current circumstances.

The Department stated that while income taxes are a fixed portion of taxable income, it is still necessary to know the Company's revenue requirements to be able to calculate the taxable income that fully and only reflects the CCOSS, and hence income taxes. The Department stated that MERC used the tools of basic linear algebra to address the circular reference problem. The Department noted that, as shown in exhibit SO-R-1 to DOC witness Dr. Ouanes Rebuttal Testimony, the ratio of income tax by taxable income for each customer class is identical to the ratio of the Minnesota Jurisdiction income tax by the Minnesota Jurisdiction taxable income.

If the proposed CCOSS allocated income taxes on a taxable income basis, calculated at the current rates, it would include embedded policy judgments as to rate design from the Company's last rate case rather than solely reflecting costs imposed by each class of customers, which is the purpose of a class cost-of-service study. Such an approach would be flawed.

If the proposed CCOSS allocated income taxes on a taxable income basis, calculated at the proposed rates, it would include proposed policy judgments, including rate design proposals, rather than solely reflecting costs imposed by each class of customers, which is the purpose of a CCOSS. This approach would also be flawed.

In his Rebuttal Testimony, Mr. Lindell testified that the Department calculated income taxes for customer classes based on some theoretical algebraic basis, presumably so higher rates can be justified for the captive residential and small customer classes. The Department noted that it recommended that income taxes be allocated in the proposed CCOSS on the basis of the taxable income attributable to each customer class that fully and only reflects the cost of providing service, rather than policy decisions based on rate design from a prior rate case.

The Department argued that this allocation is necessary because a CCOSS should solely reflect cost causality, which means that customer classes that impose costs on the system should be assigned their appropriate share of each cost. To ensure that ratepayers' long-term interests are represented when regulated public utilities propose to change their rates, it is essential not to cloud the CCOSS with policy issues that would be better addressed under rate design.

The Department noted that the OAG also recommended that income taxes should be calculated and assigned to customer classes based on taxable income for each class that reflects revenues and expenses for each class. The Department noted that a CCOSS needs to be based solely on costs. The reference to revenues in this statement is likely to result in an allocation based on factors other than costs. Different levels of revenues could be calculated: at current rates, at proposed rates, or at rates that only allow the Company to recover from each customer class the cost of providing service to that customer class. Only the last definition of "revenues" would result in costs being allocated to classes based solely on costs. Translating costs to revenues and back to costs, however, is needlessly complex.

The Department stated that it appears that Mr. Lindell proposed to use revenues calculated at current rates. The Department stated that if the proposed CCOSS allocated income taxes on the basis of taxable income, calculated at the current rates, such an allocation would include embedded policy judgments as to rate design from the Company's last rate case. The Department argued that while the Commission may choose to continue to use such a policy judgment as it sets rates in this proceeding, the Commission needs to have reasonable information as it makes its decisions. To this end, the goal of the CCOSS is to be based solely on costs imposed by each class of customers.

By contrast, allocating income taxes to customer classes based on policy judgments from MERC's prior rate case would provide skewed information to the Commission. The Department recommended that income taxes be allocated to customer classes in the CCOSS based on taxable income by class that fully and only reflects the CCOSS. The Department stated that the calculation of income taxes by class on the basis of taxable income that fully and only reflects the CCOSS results in an allocation identical to a rate base allocation. This result does not, however, mean that the "correct" income tax allocation should always be a rate base allocation.

The Department recommended that the Commission require the Company in future rate cases to calculate and allocate income taxes by class, on the basis of taxable income by class that fully and only reflects the CCOSS.

Allocation of Meter Reading Expenses (FERC Account No. 902)

The Department noted that the OAG disagreed with the Company's allocation of FERC account 902 that is based on the number of customers within each class. According to the OAG, MERC's allocation of costs does not acknowledge other cost causation factors associated with this account. In particular, large volume customers have different and more complex meters that take more time to read than do meters servicing residential customers. However, this cost causation factor is not reflected in MERC's allocation.

In its response to the Department's Information Request number 726, MERC addressed the issue of allocating meter-reading expenses by the number of customers in each class. According to the Company, FERC account 902 includes labor, materials, and expenses related to reading customer meters and determining customer usage. Most costs within this account are the two labor costs components associated with the physical act of reading meters: a) the act of reading the meter; and b) traveling to the meter to read it. The difference in the act of reading meters among customer classes is minimal: generally between two and thirty seconds. On the other hand, the bigger difference among classes is travel to read the meter. Since General Service customers do not have telemetry meters, they have a travel requirement that telemetry customers do not.

MERC witness Ms. Hoffman Malueg provided examples in support of her claim that, for General Service customers, there is no distinct, consistent variation by customer classes for the second component (traveling to the meter to read it), but there can be much variation among customers within each customer class.

Based on the Department's review of MERC's response to discovery the Department agreed with MERC's assessment.

Allocation of Customer Records and Collection Expenses (FERC Account 903)

The Department noted that the OAG agreed with the Company that FERC account 903 should be classified as customer-related costs, but disagreed with MERC's allocation of costs solely based on the number of customers within each class.

The Department stated that the Company addressed the OAG's concerns with FERC account 903. The Company's response to the Department's Information Request number 727 stated that the only significant cost differences between the customer classes as they relate to FERC account 903 are the costs attributable to administering MERC's transportation program. MERC allocated those costs separately within the CCOSS to transportation customer classes only. After removing the costs of administering MERC's transportation program, the remaining costs in FERC account

903 are related to customer service and billing functions performed for all of MERC's customers by Vertex, an external service provider. Vertex charges MERC a flat (per account) rate regardless of customer type.

Based upon current information available to the Department, it concluded that it is appropriate to allocate costs differently to transportation customers and did not recommend a change to the proposed cost allocation in FERC account 903.

Classification of Distribution Mains (FERC Account 376)

The Department noted that the OAG suggested that the Commission order MERC to classify 30 percent of the [Distribution] Mains account as customer costs and 70% as capacity costs. This suggestion is based on the OAG's zero-intercept analysis which indicates that 26% of the Mains account should be classified as the minimum system, while the rest of the system should be classified as capacity.

Due to the large difference between OAG's suggestion (30 percent of Distribution Mains to be classified as customer cost) and MERC's proposal (68 percent of Distribution Mains to be classified as customer cost), and given the questions raised by Mr. Nelson regarding the reliability of MERC's and OAG's regression analyses for the zero-intercept method used to classify Distribution Mains, the Department requested that MERC classify Distribution Mains costs using the minimum-size method, as discussed in the Gas Manual.

The Department stated that the minimum size method has the added advantage that it does not rely on a regression analysis. In the most recent general rate case decided by the Commission (Docket No. 13-316), OAG witness Mr. Nelson believed that, because it is difficult to calculate the exact costs of a zero diameter main, one should verify the results of a costs study under zero-intercept method with the results of a costs study under the minimum-size method.

In support of its study's reliability, MERC stated that the minimum system study should be based upon what is considered to be current installation standards. MERC demonstrated that a minimum-sized pipe of two inches is the most appropriate size to use when conducting a minimum-size study using the minimum-size method. MERC explained that, for MERC, 96.1 percent of plastic pipes and 95.6 percent of steel pipes less than 2" diameter were installed prior to 1992. Installations of pipes less than 2" that occurred after 1992 were unique circumstances that warranted installation of a pipe diameter less than the current installation standard. Basing any minimum system study on pipe infrastructure on anything less than two-inch pipes would not be reasonable.

MERC's response to the Department Information Request number 725 shows that at least seventy-three percent of the Distribution Mains would be classified as customer costs under the minimum-size method based on two-inch pipes. Based on its analysis and given that the outcome of MERC's minimum-size method study (seventy three percent to seventy-four percent of the Distribution Mains classified as customer costs) is consistent with the outcome of MERC's zero-intercept method study (sixty-eight percent of the Distribution Mains classified as customer costs), the Department recommended that the Commission accept MERC's assignment of Distribution Mains costs.

Summary of CCOSS Recommendations

The Department recommended that the Commission:

> Approve MERC's allocation of income taxes in the proposed CCOSS on the basis of the taxable income attributable to each customer class that fully and only reflects the cost of providing service.
>
> Accept MERC's allocation of costs in FERC accounts 902 and 903.
>
> Not accept OAG-AUD witness Mr. Ron Nelson's suggestion that the Commission order MERC to classify 30 percent of the Mains account as customer costs and 70 percent as capacity costs. The Department recommended that the Commission accept MERC's assignment of Distribution Mains costs.

Given that the only issues raised in this proceeding by any party (the allocation of income taxes, FERC accounts 902 and 903, and the classification of FERC account 376) were resolved between MERC and the Department, the Department recommended that the Commission accept MERC's proposed CCOSS as a useful tool for the purpose of setting rates.

The Department did not address the CCOSS in its Reply Brief.

OAG

Pages 33 through 57 of Initial Brief.

The OAG raised three main issues regarding MERC's CCOSS:

> The allocation of income tax.
> Allocation of FERC Account 903.
> MERC's zero-intercept analysis.

The OAG noted that the difference between customer and capacity costs is significant and, because the residential class pays significantly more of the costs that are classified as customer costs, care must be taken to properly allocate them. Classifying and allocating costs incorrectly can dramatically increase the burden on the residential class. The OAG stated that MERC uses its CCOSS to justify increasing revenue allocation for the residential and small C&I customer classes, while reducing allocation to large C&I, interruptible, and transportation classes.

The OAG noted that the Commission has previously recognized that cost of service studies cannot establish precise values, because they require considerable judgment and employ certain assumptions that might affect the results. It argued that because of its inherent imprecision, cost of service studies should be used, at most, to determine a range of class cost responsibility.

The OAG argued that MERC's improper methodology and subjective decision-making has resulted in inaccurate results in its class cost of service study. Specifically MERC's CCOSS:

Improperly allocates customer service costs by failing to account for differences in cost between customer classes.

Fails to follow the Commission's prior orders in regard to the allocation of income taxes.

Improperly functionalizes the Mains account, which represents the cost of approximately half of MERC's distribution assets.

The OAG stated that the cumulative effect of these errors is an unreasonably high allocation for residential and small C&I classes.

Income Tax Allocation in the CCOSS

In MERC's 2010 rate case, the Commission ordered the Company to allocate its income taxes on the basis of taxable income by class that fully and only reflects the CCOSS.

The OAG argued that, by allocating income tax expenses by rate base, MERC has not complied with this instruction. The OAG stated that MERC was instructed to stop allocating income taxes according to rate base years ago. In its 2008 rate case, MERC was ordered to allocate income taxes "on the basis of the taxable income attributable to each customer class, not on the basis of rate base." The Commission noted that this policy was logical because "income taxes are causally linked to income, not capital investment,"[322] and that it was the method recommended by the American Gas Association's Gas Rate Fundamentals publication.

The OAG stated that MERC has not followed the Commission's Order due to a circular reference problem: income taxes cannot be calculated until MERC estimates its expenses, and MERC's expenses cannot be calculated until MERC has determined its level of income taxes.

The OAG stated that, to justify allocating income tax on the basis of rate base, MERC attempted to demonstrate through algebraic formulas that an allocation on the basis of rate base is equivalent to an allocation based on the CCOSS. The OAG noted that MERC admits that the formulas represent only a "simplified example" of how costs and income taxes are determined. In allocating income taxes based only on rate base, MERC fails to consider the expenses that are included in a CCOSS. A cost of service study includes rate base costs, but it also includes costs from company expenses.

According to the OAG, MERC's current method is absurd from an accounting perspective because it attributes nearly a million dollars in income taxes to the residential class when the residential class did not generate any taxable income. It argued that income taxes should be allocated on the basis of income because that is the same method used to calculate total company income taxes. This method would be in accordance with the Commission's order from MERC's 2008 rate case. The OAG recommended that MERC determine taxable income by calculating

[322] Findings of Fact, Conclusions of Law, and Order, *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-007, 011/GR-08-835, at 24 (June 29, 2009).

taxable revenues minus tax deductible expenses, and then apply the corporate tax rate to determine the level of income taxes caused by each class.

Because MERC is unable to allocate income taxes based fully and only on the CCOSS due to a circular reference problem, the OAG recommended that MERC be directed to follow the Commission's next most recent instruction, which was to allocate income taxes on the basis of taxable income attributable to each customer class, not on the basis of rate base.

Customer Records and Collection (FERC Account 903)

MERC allocated its customer service and collections expenses, contained in FERC Account 903, solely on the basis of the number of customers in each class. The OAG considers this allocation unreasonable because it assumes that MERC's customer service accounts cost the same to administer for each customer. The OAG argued that common sense, as well as the treatment of these expenses by other natural gas companies in Minnesota, indicates that larger customers have more complex accounts and cost more to administer.

The OAG argued that MERC's method also deviates from the NARUC Rate Design Manual for natural gas, which recommends using a weighted customer allocator. The OAG estimated that MERC's method assigns approximately 12 percent more costs to the residential class than the weighted allocator created by CenterPoint Energy. The OAG requested that MERC be ordered to use a weighted customer allocator to remedy this error.

The OAG claimed that, of the three largest natural gas utilities in Minnesota, MERC is the only one that allocates costs from FERC Account 903 without using a weighted allocator. Xcel Energy determined that its natural gas customer service expenses could be more accurately allocated by performing studies to apply weights to the various customer classes. Its study determined that administration of a large C&I customer account costs 3.35 times more than a residential customer. Interruptible accounts cost between 13.08 and 21.23 times as much as residential accounts, and that transportation accounts cost between 8.88 and 20.97 times more than residential accounts. The OAG noted that CenterPoint Energy also uses a weighted allocator to assign customer service costs.

The OAG argued that it is unreasonable for MERC to claim that it should use a flat allocator when studies performed by the other large natural gas utilities in Minnesota demonstrate clearly that a weighted allocator is more appropriate.

The OAG noted that MERC argued that it should not be required to weight customer service costs because the services are performed by Vertex, an outside firm that charges MERC a flat, per account, rate to perform these customer services.

The OAG argued that MERC does not address whether MERC's billing arrangement with Vertex is reasonable to ratepayers. Whether Vertex bills the same rate for all customers does not mean that all customers cause equal costs. Since Vertex may spread the increased cost of serving large commercial customers across the residential customers by pricing all customers equally, the OAG stated that MERC has not demonstrated that negotiating an equal cost-per customer arrangement was based on cost causation. Such an arrangement would be unfair to ratepayers because it does not allocate the true costs for providing customer service.

In the absence of any evidence to the contrary, it is likely that MERC's true costs are similar to those of the other large natural gas utilities in Minnesota. Given the fact that other natural gas utilities and the NARUC Gas Manual recommend using a weighted allocator, the OAG requests that the ALJ recommend, and the Commission approve, that MERC be ordered to use a weighted customer allocation method for FERC Account 903.

The OAG recommended that if MERC is unable to produce a weighted allocator, MERC should be ordered to use, for this case, the allocator for FERC Account 381 recommended by the NARUC Gas Manual and that MERC be ordered to create a more precise weighted customer allocator for MERC's future rate cases.

Allocation of Distribution Mains Expenses

The OAG argued that MERC allocated the Mains Account in an unreliable manner. The Mains Account is MERC's largest single investment, and contains approximately $159 million in costs associated with the physical network of pipes that MERC uses to distribute natural gas to customers. The Commission has instructed utilities to allocate fixed costs, which are necessary only to connect a consumer to the gas system, as customer costs; all other costs should be classified as capacity costs. The distinction is significant because the residential class pays approximately 90 percent of those costs classified as customer costs, but pays approximately 63 percent of the costs that are classified as capacity costs.

The OAG argued that MERC's classification is based on data that has been manipulated beyond the point of being statistically useful. Additionally, the regression is unusable because it violates many of the basic assumptions that are necessary to ensure reliable and accurate results. As a result of MERC's inaccurate classification of the Mains Account, millions of dollars in costs have been improperly shifted to the residential class.

The OAG stated that:

> The mains account should be classified using a zero-intercept study.
> MERC's zero-intercept study is fatally flawed and should be rejected.

Zero-Intercept Study

The NARUC manual suggests two ways to determine the level of customer costs. The minimum sized main method uses the historic unit cost of the smallest main installed in the system to determine the level of customer costs. A zero-intercept method, which the Commission recently ordered CenterPoint Energy to file in its future rate cases, uses an ordinary least squares (OLS) regression to determine the customer costs from a theoretical distribution main that is zero-inches in diameter.

The OAG stated that one problem with the minimum sized method is some costs, like the material cost of the pipe, related to the main size are included as customer costs instead of capacity costs.

The OAG argued that the zero-intercept method is superior to the minimum sized main method because it recognizes that the utility installs a particular size of gas main in order to meet a certain level of demand and because "it does not include material costs." The zero-intercept method avoids this problem by using a more technically-demanding method to estimate the customer costs that result from a zero-inch diameter gas main, which will not include any material demand-related costs. The OAG claimed that MERC's zero-intercept contains so many technical errors, however, that its results are unreliable and should be rejected.

Comments on MERC's Zero-Intercept Study

The zero-intercept model is performed by conducting an OLS regression to isolate the customer costs of a distribution main system. In order to produce reliable results, an OLS regression must satisfy a series of assumptions, known as the Gauss-Markov assumptions. OAG witness Mr. Nelson reviewed MERC's OLS regression and determined that it was technically inadequate on many grounds.

The OAG stated that, rather than attempt to correct or explain the technical deficiencies identified by the OAG, MERC relied on "layman's terms" to challenge the results of Mr. Nelson's analysis. Neither MERC witness, Ms. Hoffman Malueg, nor Department witness, Dr. Samir Ouanes, addressed any of the technical issues raised by the OAG. Instead, they conclude that the results of MERC's regression are reasonable, regardless of the numerous inaccuracies identified by Mr. Nelson. The OAG stated that the Commission should reject this results-based reasoning and hold MERC to the burden of proving that its technical analysis is reliable and accurate. Mr. Nelson's uncontroverted analysis demonstrates that MERC's regression violates many of the Gauss-Markov assumptions and; therefore, the regression's results are inaccurate and unreliable.

Incorrect Specification

The OAG argued that the first step in an OLS regression is to specify a theoretical model for the study. The corresponding Gauss-Markov assumption requires that the model used in the regression be specified correctly. An incorrectly specified model introduces errors into the regression's results. MERC's model fails to satisfy this assumption because it inexplicably assumes that only one variable, to the exclusion of any other factors, has an effect on the cost of distribution mains. MERC's model is illogical and has resulted in omitted variable bias.

MERC's model proposes that the only variable that impacts a distribution main cost is the diameter of the main squared. The equation can be expressed as follows:

$$(\text{Unit Cost}) = \alpha + B1\,(\text{Main Diameter})^2 + \varepsilon$$

The OAG provided a graphical explanation of this model in initial brief. α is the zero-intercept value and represents the cost of installing a main when all variable costs are zero. The ultimate purpose of the OLS regression is to determine the value of α, because α is the customer associated with installing one foot of main. Any costs in excess of α should be classified as capacity costs.

The OAG stated that MERC's specification is flawed because it assumes that the only variable that influences the unit cost of a gas main is the diameter-squared of that particular main. The record in this case demonstrates that MERC has excluded many variables from its model including route selection, depth of installation, number and material of fittings, number of valves, and installation location geography. MERC witness Mr. David Kult noted that there are varying construction costs across the State of Minnesota caused by geographic area, type of soil, size of lot, [and the] amount of gas used. The OAG stated that MERC's own authority and witnesses indicate that these variables affect cost, and should have been included in MERC's model. It is commonly accepted that, to increase accuracy and reliability, a regression model which includes a quadratic variable, such as diameter-squared, should also include the linear variable, which would be represented as diameter. Each of these factors may have a statistically significant impact on the cost of a gas main and MERC's model fails to account for this.

The OAG added that the Integrys Gas Group Engineering Manual and common sense indicate that the number of valves in a gas main will have an impact on cost. The consequence of MERC failing to account for the number of valves in its model is that, instead of calculating the true fixed costs of installing a foot of gas main, MERC has calculated the fixed costs plus the costs of valves.

The OAG noted that every variable that is excluded from MERC's model creates the same effect, magnifying the error. The cumulative result of these omissions is that MERC's estimate of the fixed costs for the distribution system includes many variable costs that should not be classified as customer costs.

MERC argued that the variables suggested by the OAG are either already included in MERC's model or cannot be included because MERC is unable to provide data for the variables. The OAG responded that data availability for the variables suggested by Mr. Nelson is not relevant to whether their omission has irreparably biased MERC's model. If the variables should have been included in the model but were not, then model is flawed, regardless of whether MERC has collected data.

The OAG disagreed with the claim that MERC's model includes the variables because they are contained within book costs. MERC witness Ms. Hoffman Malueg's statement that variables, such as the number of fittings and valves, are included in the book cost is an admission they have an effect on the cost of a mains project and should have been included in the model to ensure that their costs were not included in customer costs. Ms. Hoffman Malueg's reference to book value is an admission that these variables affect unit cost data, represented on the left side of MERC's model. By failing to control for them on the right side of the equation as well, MERC has introduced omitted variable bias into its results.

The OAG stated that the technical analysis performed by Mr. Nelson confirms that MERC has not specified its model correctly. After reviewing the results of MERC's OLS regression, Mr. Nelson conducted the specification error test for omitted variables. The results of the specification error test demonstrated that MERC's model was incorrectly specified, that the parameters estimated in the model were estimated incorrectly, and that it is highly probable that the unit cost for a zero inch main is incorrectly estimated in MERC's zero-intercept model.

The OAG claimed that, since neither Department witness Mr. Samir Ouanes nor Ms. Hoffman Malueg performed a similar test, Mr. Nelson's technical analysis is unopposed on this point. The OAG recommended that the Commission reject MERC's classification of the Mains Account as inaccurate and unreasonable.

Data Manipulation

The OAG also identified problems with MERC's treatment of data in its zero-intercept study. The data set that MERC used in its regression includes two variables, the diameter-squared of the main and the unit cost of installing that size of main in a particular year. Instead of using minimally processed data, MERC used manipulated data to construct both the unit cost and diameter-squared of main. The OAG argued that MERC's data management practices result in "a data set that is not fit for a zero-intercept analysis," and "all results from any such analysis [are] meaningless."

MERC introduced errors into the process as early as the first data gathering steps. Instead of collecting original data from main installation projects, MERC began its analysis with data that had already been aggregated by diameter and year. The OAG argued that aggregating data in this way is detrimental to the accuracy of a regression because the aggregation "can destroy the relationship that a regression is attempting to model." The OAG claimed that this process damaged the reliability of any conclusions about the relationship between the diameter-squared of a pipe and unit costs of mains projects.

The OAG argued that MERC intentionally altered more than 25 percent of the data sets in its sample by relabeling mains that were less than 2-inches as 2-inch main. In addition to altering the size of mains, MERC manipulated the data for unit cost. In the original data, the cost of installing a main varies by year. Instead of using this original data, MERC averaged the cost for each diameter across time, and reported the average as the cost in each year. MERC's data set includes 128 data points for 2 inch mains. In its original form, each of the 128 data points would have a different cost. After MERC's data manipulation, each of the 128 data points for 2 inch mains indicates that the cost of installing one foot of 2 inch main was exactly $13.72. After the manipulation, the data set appears to lead to the conclusion that every 2-inch main ever installed in MERC's distribution system has exactly the same cost. At this point, MERC's data no longer describes a variable; it describes a predetermined relationship between size and cost with no variability. The OAG claimed that MERC's data is beyond repair.

Comparing a hypothetical example of what MERC's original data set would look like, the OAG stated that the data points for 3-inch diameter main have different adjusted unit costs in different years. This was not the data that MERC used in its regression. Instead, MERC calculated an average unit cost for each main diameter over all of the years in the data set. The hypothetical example was used to demonstrate the result of MERC's manipulation. In the example, the data is averaged so that it appears that every data point has the same cost.

By averaging the data, MERC eliminated all variability from the sample and, as a result, each data point is identical. The OAG claimed that in the process of manipulation, MERC changes the unit cost of every single observation to the same number for each diameter of main. As a result, MERC has stripped the data of its meaning and rendered it not only useless, but misleading. OAG witness Mr. Nelson noted that the point of econometrics is to determine a relationship, but MERC distorts the relationship between the two variables and makes it seem like the dependent variable is perfectly predicted by the independent variable.

Instead of attempting to analyze this variation, MERC has predetermined the relationship between the size of the main and the unit cost. The consequence of this manipulation is that MERC's model is completely meaningless and should be disregarded.

Mr. Nelson analyzed the results of MERC's regression for the presence of outliers by performing a stem and leaf plot test. The results of the test indicated that 78 of the 266 observations in the plastic data, almost 30 percent, were outliers. The OAG argued that the outliers will result in an incorrectly estimated model because they can overly influence the prediction of the Y variable. The presence of any outliers in a data set can result in bias; a data set that consists of 30 percent outliers is, by definition, unreliable.

The OAG argued that no party in this case has contradicted Mr. Nelson's technical analysis. Mr. Nelson's unchallenged technical analysis demonstrates that nearly 30 percent of MERC's regression data are outliers, and that as a consequence MERC's regression should be rejected as inaccurate and unreliable.

Heteroscedasticity

The OAG argued that MERC's regression also violates the Gauss-Markov assumptions of homoscedasticity. The OAG claimed that Department witness Laura Otis explained this assumption by noting that, "One of the basic assumptions for regression analysis is that the error terms [of the regression] must have the same variances." When the error terms have different variances, the regression has heteroscedasticity. According to Ms. Otis, the consequence of heteroscedasticity is that the estimated variances and covariances of regression estimates are biased and inconsistent.

The OAG claimed that, since MERC witness Dr. Harry John noted that the major consequences of heteroscedasticity are that the predicted values will have large errors, leading to imprecise estimates. The potential for large errors will increase significantly in the presence of heteroscedasticity, and as a result all statistical tests of the model such as T-statistics, and F-test will be unreliable.

The OAG claimed that a diagnostic test to check for heteroscedasticity provided clear evidence that heteroscedasticity was present which, according to expert opinions, means that MERC's regression is unreliable. MERC made no attempt to test for the presence of heteroscedasticity even after reviewing Mr. Nelson's evidence.

The OAG stated that the uncontroverted analysis demonstrates that MERC's regression contains heteroscedasticity and should be rejected as inaccurate and unreliable.

The OAG's Zero-Intercept Study

OAG witness Mr. Nelson conducted an alternative zero-intercept analysis. Mr. Nelson acknowledged that his analysis was limited by the data provided by MERC; as a result of MERC's data manipulation it would be impossible to perform an OLS regression that did not suffer from some problems. Given these limitations, the OAG claimed that, to increase the model's flexibility, providing a superior theoretical specification, increase the model's measure of fit, and align with theory and other zero-intercept analyses completed in additional jurisdictions, Mr. Nelson included the linear diameter variable to the model. With these changes, the OAG's regression suggested that 26 percent of the Mains Account should be classified as customer costs.

To check his results, Mr. Nelson conducted a literature review to compare his results to that of other utilities that had conducted a zero-intercept analysis. MERC's request to classify 70 percent of the Mains Account as customer costs was extremely high compared to the results of other zero-intercept studies. The average zero-intercept study indicated that 35.63 percent of a distribution system should be classified as customer costs. Given that the results of his study were below the average, and that they were limited by the significant problems with MERC's data, Mr. Nelson recommended that the Commission classify 30 percent of the Mains Account as customer costs.

The OAG noted that MERC did not provide any technical analysis supporting its position to reject the OAG's study. It relied on layman's terms to engage with Mr. Nelson's technical arguments.

The OAG noted that, despite not providing any technical analysis of the regression and testifying that he did not analyze the regression at all, Department witness Dr. Ouanes recommended that the Commission reject Mr. Nelson's results. Even though he reviewed the technical issues that were raised by Mr. Nelson, Dr. Ouanes accepted the results of MERC's regression based on alternative minimum-sized studies.

The OAG argued that the Company and Department believe that, since the results of MERC's zero-intercept study are close to the results of the minimum-sized studies, MERC's recommendation must be accurate. However, all of the parties in this matter agree that the minimum-sized study overestimates the customer costs of a distribution system. The Department appears to assume that the results of the two systems should be similar, but there is no theoretical reason that the results of the minimum-system study should be similar to the results of a zero-intercept study.

The OAG noted that MERC witness Ms. Hoffman-Malueg agreed that a two-inch pipe would allow more demand costs than a zero-inch pipe, and noted that the zero-inch pipe would better identify the customer costs of the system because it would not allow any demand costs.

The OAG argued that the Department failed to recognize the results of MERC's third minimum-sized study. The third study, the only one in which MERC based its model on the lowest cost mains in the system, indicated that 32 percent of the distribution system should be classified as customer costs. This result is a classification that is nearly identical to the classification proposed by Mr. Nelson.

The OAG argued that the result of MERC's improper classification of the mains account is that the cost of service for the residential class is overstated by nearly 2.5 percent. Mr. Nelson's testimony demonstrates that MERC's regression is inaccurate and unreliable because it contains excessive outliers, heteroscedasticity, and omitted variable bias. Mr. Nelson's analysis addresses the technical faults of MERC's study, adheres to cost of service study methodology accepted by the authorities in this field, and proposes a classification that is fair and reasonable for all classes. As a result, Mr. Nelson's recommendation would reduce the residential class' revenue deficiency by nearly 20 percent, or $3.85 million. The OAG requested that the Commission approve classifying 30 percent of the Mains Account as customer costs, and 70 percent of the Mains Account as capacity costs.

The OAG also recommended that, in order to run a superior, or at least valid, zero-intercept analysis in future cases, the Commission order MERC to collect data on additional variables. Specifically, the OAG recommends that the Commission order MERC to:

1. Collect data on additional variables that impact the unit cost of mains installation as recommended by Mr. Nelson;

2. Avoid aggregating or averaging data and use data at the finest level reasonable;

3. Check OLS regression assumptions and correct for violations; and

4. Make any future zero-intercept analysis more transparent to ensure that MERC's work can be easily replicated.

The OAG stated that these recommendations are the minimum necessary steps to conduct a valid zero-intercept study.

OAG Reply Brief

Pages 1 through 8 of Reply Brief.

Classification of Gas Mains

According to the Commission's prior orders, only the costs that are necessary to connect a customer to the gas system should be classified as customer costs; the remaining portion of the Mains Account should be classified as capacity costs and be allocated based on each class' contribution to peak demand.

The OAG repeated the concept behind the zero-intercept method and noted that, in its Initial Brief, the OAG demonstrated that MERC's zero-intercept study is inaccurate and should be rejected as a method for classifying the Mains Account.

The OAG repeated that its technical analysis is still uncontroverted. Neither MERC nor the Department provided any technical evidence to rebut the fact that MERC's zero-intercept study is unreliable. It noted that MERC argued that, due to cost and volume, it should not be required to collect the data that is necessary to conduct a reliable zero-intercept study in the future. The OAG argued that MERC has not provided any evidence of how much such data collection might cost.

The OAG argued that MERC failed to recognize that, as a regulated utility, it is required to ensure that it allocates its costs accurately. MERC is obligated to collect any data that is necessary to produce an accurate allocation of its costs whether or not it has been specifically ordered to do so. By definition, any costs that are necessary to conduct an accurate zero-intercept study are costs that the utility should incur to make sure it is allocating its expenses properly. MERC should collect data on at least enough variables to conduct a zero-intercept study that can satisfy the econometric assumptions that are necessary to produce an accurate result.

The OAG noted that MERC's second response to the OAG's technical challenge is that its method of aggregating and averaging data is the proper way to conduct a zero-intercept study. The OAG restated its argument that MERC's aggregation and averaging method used to conduct its ordinary least squares regression destroyed any relationship between the data in its original form. MERC's data manipulation is inappropriate and not supported by statisticians.

The OAG argued that MERC does not understand the zero-intercept method. The NARUC Gas Manual describes how to perform a minimum-size main study, not a zero-intercept study. Specifically, the NARUC Gas Manual describes two methods to allocate the costs of a distribution system: the minimum size main study, and the zero-inch main method. The Manual then states, "A calculation of a minimum size main is shown in the illustrative cost allocation study." The NARUC Gas Manual discusses aggregation and averages because that is how a minimum-size main study is performed. Because usage of aggregate and average data in this fashion renders an ordinary least squares regression useless, it cannot be used to perform a zero-intercept study.

The OAG noted that MERC argued that the OAG's recommendations are improper because they are not based on MERC's current installation practices. It appears that MERC means the zero-intercept study should be based, in some way, on MERC's current practice of installing primarily 2-inch mains. MERC's insistence that its classification method should reflect this preference for 2-inch main is another example of how MERC misunderstands the zero-intercept analysis and how it classifies gas main costs. The purpose of the zero-intercept study is to determine the cost of connecting a customer to the gas system without reflecting any costs that are related to the size of the pipe used to make the connection. Because it would connect a customer to the system without including any capacity costs, the zero-intercept study measures the cost of a theoretical pipe that is zero-inches, or has no size, in diameter. Since it would produce useless results that provided no information on the actual costs of connecting a customer to the gas system, a zero-intercept study that reflected the costs of a 2-inch main instead of a zero-inch main would defeat the purpose of conducting the study.

The OAG noted that MERC also argued that its proposed allocation is supported by the results of several minimum-size main studies. MERC believes that the similarity between the results of the minimum-size studies and its zero-intercept study indicate that the zero-intercept study was performed correctly. The OAG argued that this is not the case.

The record in this case, as well as a basic understanding of the theory involved, demonstrates that the minimum-size main method overstates the cost of connecting a customer to the gas system. Common sense reaches the same result: a 2-inch main, such as MERC used for its studies, costs more to install than a zero-inch main. But only the costs of the zero-inch main are necessary to connect a customer to the system, and the additional costs of the 2-inch main are costs that MERC has incurred in order to provide the capacity of a 2-inch main. For this reason, a minimum-size study based upon a 2- inch main overstates the cost of connecting a customer, and improperly shifts the costs of the Mains Account to the residential class.

The OAG noted that MERC's third minimum-size main study demonstrates MERC's basic confusion about the theory of minimum system studies. MERC believes that the third study is flawed because it "did not consider MERC's minimum installation standards." But the fact that MERC's other studies did reflect the minimum installation standards means that it included some costs that are related to the capacity of a 2-inch main, rather than calculating only the cost necessary to connect a customer to the gas system. When MERC finally conducted a study that did not reflect its claimed minimum installation standards, the results of the study were similar to the results of the OAG's zero-intercept analysis. For that reason, MERC's third minimum-size study is likely to be the most accurate. Given that this third study reaches results that are very similar to the results of OAG witness Mr. Ron Nelson, the OAG recommends that the Commission approve Mr. Nelson's recommendation to classify 30 percent of the Main Account as customer costs, and 70 percent of the Mains Account as capacity costs.

Customer Records and Collection (FERC Account 903)

The OAG noted that MERC claims that the OAG recommended that Account 903 be allocated on the basis of the average cost for meters when, in fact, it does not. Contrary to MERC's claim, OAG witness Mr. Nelson's primary recommendation was that MERC be ordered to use a customer weighted allocation method for FERC account 903.

According to Mr. Nelson, MERC should create a customer weighted allocator similar to the weighted allocators used by CenterPoint Energy and Xcel Energy because some customers "have much more complex billing, accounting, contracts, and complaints than do residential customers," and MERC's current allocation failed to take those differences into account.

Given the fact that MERC has not yet created such an allocator, Mr. Nelson noted that the NARUC Gas Manual, which also uses a weighted allocator, recommends an allocator that is also used for Account 381, which contains expenses related to meters. Mr. Nelson ultimately recommended using a customer weighted allocator by either creating its own allocator or using the allocator suggested by the NARUC manual.

MERC's current allocation does not account for the differences in the cost of providing customer services to different customer classes and has not provided any evidence demonstrating that its allocation method is reasonable. The OAG argued that MERC's flat rate contract with Vertex does not represent the principles of cost causation and should not be used to develop an allocation method for Account 903. The OAG recommended that MERC be directed to use a weighted customer allocator for Account 903. If MERC is unable to provide a weighted customer allocator of its own, the OAG recommends that MERC use the weighted allocator described in the NARUC Gas Manual.

ALJ Report on CCOSS

In finding 623 the ALJ stated that the CCOSS analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes.

Zero-Intercept and Minimum Size Analyses

In findings 625 through 638 the ALJ discussed the zero-intercept and minimum size analyses.

In finding 631 the ALJ stated that, while serving the same purpose as a zero-intercept method study, a minimum size method study has an advantage: It does not rely upon regression analysis for its results. Instead, an analyst needs to consider whether the study should utilize the size of the equipment that is currently installed, historically installed, or the minimum size needed to meet safety standards.

In finding 635 the ALJ noted that the OAG testimony raises two distinct issues: the appropriate CCOSS methodology and the reasonableness of the resulting allocations.

In finding 636 the Administrative Law Judge concluded that the OAG's critiques are not well taken. Neither MERC, nor other utilities in Minnesota, have been required to maintain the types of historical data urged by the OAG for CCOSS analysis. Only one utility in Minnesota maintains the type of data that the OAG regards as "project level" detail. Some of the data points that OAG-AUD would include in the analysis – such as the length of the distribution main, or the reason why the pipe was installed – contribute very little to development of "a hypothetical zero-load or zero-sized distribution main on MERC's entire system."

In finding 637 the Administrative Law Judge concluded that a proper zero-intercept analysis should reflect the costs of actual steel distribution mains and industry minimums for installation of such mains.

In finding 638 the ALJ found that MERC's minimum size analysis demonstrates that at least 73 percent of the distribution mains would be classified as customer costs and 27 percent to demand costs.

Customer Records and Collection Expense (Account 903)

The ALJ discussed Customer Records and Collection Expense (Account 903) in findings 639 through 643.

In finding 642 the ALJ noted that the amounts in Account 903 are primarily the costs of retaining Vertex, an external service provider, to perform MERC's customer service and billing functions for all of MERC's customers. Vertex charges MERC a flat, per account rate to perform customer services and there is no difference in the flat rate charge amongst the different types of MERC customers.

In finding 643 the ALJ stated that MERC's allocation of Customer Records and Collection Expenses follow directly from its actual, arms-length transaction with Vertex, and is reasonable.

Allocation of Income Taxes

The ALJ addressed the allocation of taxes in findings 644 through 648.

In finding 648 ALJ stated that MERC's allocation of taxes is consistent with MERC's prior rate cases, the methodology used by other utilities, and produces reasonable allocations in this instance.

Meter Reading Expenses (Account 902)

In finding 649 the ALJ noted that the Department, OAG and MERC agree on MERC's allocation of Meter Reading Expense (Account 902).

CCOSS Conclusion

In finding 650 the ALJ found that MERC's CCOSS fully and correctly demonstrates the embedded fixed costs of residential service.

In finding 651 the ALJ found that MERC's CCOSS should be adopted in this proceeding and used as a basis for revenue apportionment and rate design.

Exceptions to the ALJ Report

MERC and the Department did not file exceptions to the ALJ's CCOSS Findings.

Office of the Attorney General

The OAG addressed the CCOSS on pages 2 through 8 of its Exceptions to the ALJ Report.

The OAG filed exceptions to the ALJ's findings on the CCOSS. The OAG claimed that through its testimony and briefing, it demonstrated that MERC's Class Cost of Service Study was inaccurate, and that it would be unreasonable to rely on the study for apportionment or rate design. The OAG disagreed with the ALJ's recommendation that the Commission should adopt MERC's CCOSS in this proceeding.

The OAG stated that by failing to describe the OAG's analysis, the ALJ has presented the Commission with a report that does not fairly describe what took place during the proceeding.

Mains Account Allocation

The OAG stated that the mains account is MERC's single largest investment, and changes in its allocation have a significant impact on the result of the CCOSS. The OAG argued that it provided extensive analysis on ways in which MERC's zero-intercept model violates the basic principles of ordinary least squares regression analysis. The OAG noted that the ALJ did not make any findings describing the substance of the OAG's analysis.

The OAG recommended that Finding 626 be modified to remove the reference to the practice of Integrys affiliates in other jurisdictions. It stated that the fact that other utilities may use similar methods in other jurisdictions is irrelevant to whether MERC's method in this case is correct. The OAG has demonstrated that MERC's zero-intercept method is incorrect and leads to inaccurate results. The method cannot be salvaged merely because it was used elsewhere. The OAG recommended the following modifications to Finding 626:

> 626. MERC's zero-intercept study was based upon data that is available and complete. ~~The Company's assumptions, specifications and statistical techniques were similar to, and consistent with, those used by Integrys's other subsidiaries.~~

The OAG recommended that Finding 628 be modified to provide a description of how the OAG demonstrated that MERC's zero-intercept method was incorrect. The OAG recommended that the following changes be made to Findings 628 and 629 to reflect its analysis:

> 628. The OAG-AUD argues that MERC's CCOSS analyses were flawed and produced unreasonable results. <u>The OAG identified several flaws within MERC's zero-intercept study:</u>
>
> > <u>a. The OAG noted that MERC's model was incorrectly specified because it assumed that only one variable had any effect on the cost of a distribution main: the diameter of the main squared. The Integrys Gas Group Engineering Manual, the testimony of MERC witness Mr. Kult, bids from MERC's contractors, and common sense lead to the conclusion that other variables have an impact on the price of a distribution system, and should be included in the model. Failing to include these variables in the model leads to omitted variable bias, which OAG witness Mr. Nelson was able to confirm using statistical analysis. The result of omitted variable bias is that cost of a zero-inch main is incorrectly estimated.</u>
> >
> > <u>b. The OAG also discussed MERC's data handling. MERC took several unreasonable steps with its data practices, including aggregating and averaging data before using it in its zero-intercept analysis. The OAG argued that by manipulating the data in this fashion, MERC had predetermined the results of the regression and that the results of the model were completely meaningless.</u>
> >
> > <u>c. The OAG also determined using statistical analysis that MERC's regression contains heteroscedasticity, or that the error terms of the regression have different variances. Mr. Nelson confirmed the presence of heteroscedasticity using the Bruesch-Pagan test. A model with heteroscedasticity does not produce accurate results.</u>

~~For this case, and on a going-forward basis, the OAG-AUD recommended that MERC:~~

~~(1) Assess a greater number of cost-related variables;~~

~~(2) Maintain cost data at the project level;~~

~~(3) Avoid aggregating or averaging this data; and~~

~~(4) Change the percentages used to classify MERC's distribution mains, based upon the OAG-AUD zero-intercept study and the results of other available studies.~~

629. After providing evidence that MERC's zero-intercept study was flawed, OAG witness Mr. Nelson produced an alternative zero-intercept study that corrected some of the errors from MERC's model. Mr. Nelson's improved model indicated that 26% of the Mains account should be classified as customer costs. Given that his method was still limited to some extent by the problems with MERC's data, Mr. Nelson recommended that 30% of the Mains Account be classified as customer costs. ~~The OAG-AUD recommended a very different allocation of costs; specifically, a 30 percent customer classification for the Mains account and allocation of 70 percent in demand costs.~~

The OAG also took exception to the ALJ's discussion of MERC's minimum size studies. The OAG recommended the following modifications to Findings 631 and 634:

631. The minimum size method serves a similar, but distinct, purpose from the zero-intercept method. The zero-intercept method attempts to calculate a no load distribution system by analyzing the cost of a zero-diameter pipe that connects a customer to the system but carries no gas. In contrast, the minimum size method attempts to calculate the cost of a system that does carry load by calculating the cost of the "minimum" sized equipment. ~~While serving the same purpose as a zero-intercept method study, a~~ The minimum size method study has an advantage: It does not rely upon regression analysis for its results, and is therefore easier to conduct. Instead, an analyst needs to consider whether the study should utilize the size of the equipment that is currently installed, historically installed, or the minimum size needed to meet safety standards. Additional criteria could include when the equipment was installed and whether the equipment is installed throughout the entire system or only in limited locations. While the minimum size method has the advantage of being easier than the zero–intercept method, it can also be less accurate because it calculates the cost of a distribution system that includes gas. By including load in its calculation, the minimum size method classifies some capacity costs as customer costs. While the zero-intercept method is more complex because it requires a regression, it more accurately calculates the customer costs because it estimates the cost of a system with no load.

634. The third minimum size study allocated distribution main costs on the basis of the mains with the lowest unit cost to install that are installed in MERC's system and without altering the size of any mains.~~but did not utilize MERC's minimum installation standards.~~ The study produced ~~very different results than the other studies –~~ an allocation of 32.04 percent in customer costs and 67.96 percent in demand costs.

The OAG took exception to Finding 636. The OAG stated that the ALJ made no findings on the substance of the OAG's reasoning and analysis. Rather than reaching a conclusion on the merits of the OAG's recommendation to classify 30 percent of the Mains Account as customer costs, the ALJ focused on the OAG's recommendation that MERC be ordered to collect additional data for its next rate case so that its zero-intercept model will be more accurate in the future. The OAG stated that it does not recommend that MERC be ordered to collect all the data mentioned by Mr. Nelson. The OAG recommended that the Commission order MERC to collect data on additional variables in order to run a superior, or at least valid, zero-intercept analysis in future cases.

The OAG recommended the following modifications to Finding 636:

> 636. With respect to the recommended approaches for the CCOSS, <u>the ALJ believes that the analysis provided by the OAG has merit. The ALJ agrees that MERC should collect additional data for zero-intercept studies in future so that the Commission will be presented with more accurate and reliable analysis</u>.~~the Administrative Law Judge concludes that the OAG-AUD's critiques are not well taken. Neither MERC, nor other utilities in Minnesota, have been required to maintain the types of historical data urged by the OAG-AUD for CCOSS analysis. Moreover, only one utility in Minnesota maintains the type of data that the OAG-AUD regards as "project level" detail. Lastly, some of the data points that OAG-AUD would include in the analysis – such as the length of the distribution main, or the reason why the pipe was installed – contribute very little to development of "a hypothetical zero-load or zero-sized distribution main on MERC's entire system."~~

The OAG took exception to the ALJ's finding that a zero-intercept analysis should reflect "industry minimums for installation of such mains." The OAG stated that MERC's insistence that its classification method should reflect the preference for 2-inch main is an example of how MERC misunderstands the zero-intercept analysis and how it classifies gas main costs. The very purpose of the zero-intercept study is to determine the cost of connecting a customer to the gas system without reflecting any costs that are related to the size of the pipe used to make the connection. The OAG stated that by recommending that a zero-intercept study be based on something other than a zero inch, zero-load main, the ALJ reveals a lack of understanding about the basic purpose and theory of a zero-intercept study. The OAG recommended that Finding 637 be removed entirely.

> ~~637. With respect to the reasonableness of the study results, the Administrative Law Judge concludes that a proper zero-intercept analysis should reflect the costs of actual steel distribution mains and industry minimums for installation of such mains.~~

The OAG took exception to the ALJ's final recommendation on the classification of the Mains Account. The OAG noted that the ALJ selected a level of customer costs that no party recommended as reasonable. The OAG argued that it presented extensive analysis demonstrating that 30 percent of the Mains Account should be classified as customer costs, and 70 percent of the Mains Account should be classified as capacity costs.

The OAG recommended the following modifications to Finding 638:

638. ~~MERC's minimum size analysis demonstrates that at least 73~~ Thirty percent of the distribution mains ~~would~~should be classified as customer costs and ~~27~~seventy percent to demand costs.

Customer Records and Collection Expense Allocation

The OAG claimed that the ALJ incorrectly stated the OAG's recommendation on the allocation of FERC Account 903 and fails to present the OAG's reasoning as to why MERC's current allocation method is not based on the principles of cost causation. MERC currently allocates Account 903 based solely on the number of customers in each class. The OAG stated that studies conducted by other utilities all indicate that different customer classes create different levels of customer service costs.

The OAG recommended modifying Finding 643 and 644 to include additional findings to reflect the record in this case and that MERC failed to meet its burden of proof on this issue.

643. The OAG responded to MERC's argument by noting that other utilities in Minnesota have conducted studies demonstrating that customer classes cause costs at different levels per customer. Based on this evidence, the OAG argued that MERC's current allocation method was not based on the principles of cost causation, and that MERC should be instructed to use a weighted customer cost allocator.

644. MERC has not met its burden of proof to demonstrate that its customer service costs should be allocated based only on the number of customers in a class. The ALJ recommends that MERC allocate its customer service costs using a weighted customer allocator that measures how different customer classes cause customer service costs. In addition, the ALJ recommends that MERC be ordered to perform a study before filing its next rate case to determine how to weight customer service costs.~~MERC's allocation of Customer Records and Collection Expenses follow directly from its actual, arms-length transaction with Vertex, and is reasonable.~~

The language the OAG proposed striking in 644 above is from Finding 643. Finding 644 addresses allocation of income taxes.

Meter Reading Allocation

The OAG stated that the ALJ incorrectly states the OAG's position on the allocation of FERC Account 902 which represents meter reading costs. While the OAG is no longer pursuing the issue in this case, the OAG does not agree that MERC's allocation is reasonable. The OAG recommended that Finding 649 be updated to reflect the OAG's position.

649. The Department, ~~OAG-AUD~~ and MERC agree on MERC's allocation of Account 902: Meter Reading Expense.

Staff Comment

Finding 650 appears to be inconsistent with the Commission's recent decisions regarding CCOSS. In Finding 650 the ALJ states MERC's CCOSS full and correctly demonstrates the embedded fixed costs of residential service.

As discussed by MERC and the OAG, the class cost of service study is a subjective tool that requires judgment and employs assumptions that might affect the results. As a result, there is no single correct CCOSS for a utility. This view is reflected in previous Commission decisions. In its May 24, 2010 Findings of Fact, Conclusions of Law, and Order, in Dakota Electric Association's 2009 rate case, Docket No. E-111/GR-09-175, the Commission stated at page 12:

> Because these studies require considerable judgment and employ certain assumptions that might affect the results, they cannot establish precise values. Rather, they provide a rational basis for making determinations about cost causation for cost allocation purposes.
>
> The study is a starting point for establishing rates and recovering revenue from each customer class at a level that takes its costs into account. It is generally accepted that the study should be used to determine a range of class cost responsibility and not precise values.

On page 14 the Commission added:

> For all of these reasons, the Commission finds that although a CCOSS cannot precisely determine the actual costs of serving each rate class, . . .

On page 47 of its August 12, 2011, Findings of Fact, Conclusions of Law, and Order, of Interstate Power and Light Company's 2010 rate case, Docket No. E-001/GR-10-276, the Commission stated:

> A Class Cost of Service Study (CCOSS) is a tool that is used to aid in the determination of which customer classes cause which costs by evaluating the load and service characteristics of the classes. The study is a starting point for establishing rates and recovering revenue from each customer class at a level that takes its costs into account. It is generally accepted that the study should be used to determine a range of class cost responsibility and not precise values.

The Commission has required companies to conduct additional CCOSS. In its June 9, 2014 Findings of Fact, Conclusions, and Order, in CenterPoint Energy Resources Corp.'s most recent rate case, Docket No. G-008/GR-13-316, the Commission required Center Point Energy Resources to, in its next rate case, file a minimum system study based on a one-inch and a zero-inch pipe, in addition to the two-inch pipe it has traditionally used.

Commission Options Regarding the CCOSS

Some Commission options regarding the CCOSS are:

Precision

1. Determine that because a CCOSS is not precise, it should not be used in rate setting.

If the Commission adopts one of either of the preceding options it may want to strike or modify Findings 650 and 651.

2. Determine that although a CCOSS is not precise, it can be a useful tool for setting rates.

If the Commission adopts one of either of the preceding options it may want to strike or modify Finding 650.

3. Make no determination.

Allocation of Income Tax for CCOSS

4. Determine that, for the Class Cost of Service Study, taxable income should be based on allocation of costs within the Class Cost of Service Study (allocated by class on the basis of taxable income that fully on only reflects the CCOSS.) (MERC, DOC, ALJ)

5. Determine that MERC's Class Cost of Service Study should allocate income tax expense on the basis of taxable income attributable to each customer class, not on the basis of rate base. (OAG)

6. Make no specific determination on the appropriate allocation of taxes within the CCOSS.

Allocation of Income Tax in CCOSS for Future Rate Cases

7. Determine that, in future rate cases, MERC should allocate income taxes by class on the basis of taxable income that fully on only reflects the CCOSS. (MERC, DOC)

8. Make no determination regarding the treatment of income tax in the CCOSS of future rate cases.

Meter Reading (FERC Account 902)

9. Approve MERC's proposed allocation of FERC Account 902: Meter Reading. (MERC, DOC, ALJ)

10. Determine that some other allocation of FERC Account 902 is appropriate.

11. Make no specific determination regarding FERC Account 902.

12. Regardless of its decision on this issue, the Commission may want to:

Modify Finding 649 as proposed by the OAG to be consistent with the OAG's position that it does not agree that MERC's allocation is reasonable.

Customer Records and Collection (FERC Accounts 903)

13. Determine that MERC's allocation of Account 903 costs reasonable. (MERC, DOC, ALJ)

14. Determine that a weighted customer allocation method should be used for FERC Account 903. (OAG)

Determine that if MERC is unable to produce a weighted allocator:

a. The allocator used for FERC Account 381, as recommended by the NARUC Gas Manual, be used for this case; and

b. MERC create a more precise weighted customer allocator for MERC's future rate cases.

If the Commission adopts the OAG's position, it may also want to:

Adopt the OAG's proposed modifications to Finding(s):

i. 643
ii. 644.
(Staff notes that the language in OAG's proposed modification 644 is from ALJ Finding 643.)

15. Make no determination regarding the allocation of FERC 903 in this proceeding.

Study for Allocating Distribution Main Expenses

16. Determine that the gas distribution system should be classified and allocated using a zero-intercept method.

17. Determine that a gas distribution system should be classified and allocated using a minimum size main method.

18. Make no specific determination on the appropriate method for classifying and allocating the gas distribution system.

19. Adopt the OAG's proposed modifications to Finding 631 to provide more explanation of the differences between the minimum size method and the zero-intercept method. (OAG)

20. Adopt the OAG's proposed modifications to Finding 634 to clarify how MERC conducted its third minimum size study. (OAG)

Allocation of Distribution Mains

21. Determine that 68.3 percent of MERC's distribution mains should be classified as customer costs and 31.7 percent should be classified as demand costs. (MERC, DOC, ALJ)

22. Determine that 30 percent of MERC's distribution mains should be classified as customer costs and 70 percent should be classified as demand costs. (OAG)

    If the Commission makes this determination (#22) it may want to:

    Adopt the OAG's proposed modifications to Finding(s):

    i. 626
    ii. 628
    iii. 629
    iv. 636
    v. 637
    vi. 638

Commission Options Regarding Overall CCOSS

23. Determine that a CCOSS should not be specifically adopted.

    If the Commission makes this determination (#23) it may want to strike findings 650 and 651.

24. Accept MERC's CCOSS as a useful tool for the purpose of setting rates. (MERC, DOC)

25. Accept MERC's CCOSS.

    If the Commission makes this determination (#25) it may want to:

    Adopt the OAG's proposed modifications to Finding(s):

    i. 626
    ii. 628
    iii. 629
    iv. 636

v. 637
vi. 638

26. Modify MERC's CCOSS to reflect any adjustments the Commission has made above.

27. Accept the OAG's CCOSS

Data Collection for Future CCOSS

28. Determine that the Company is collecting and keeping sufficient data for the CCOSS. (MERC, DOC,)

29. Determine that MERC needs to keep better information for a CCOSS and require MERC to:

    a. collect data on additional variables that impact the unit cost of mains installation;

    b. avoid aggregating or averaging data and use data at the finest level reasonable;

    c. check OLS regression assumptions and correct for violations; and

    d. make any future zero-intercept analysis more transparent to ensure that MERC's work can be easily replicated.

30. Modify Finding 628 to reflect the OAG's position by striking the portions the OAG recommended striking.

31. Make no decision regarding the data for future CCOSS.

Clarification

32. Adopt the OAG's recommendation to strike Finding 637.

(Note: These decision alternatives correspond to alternatives 151 through 182 on the deliberation outline.)

Rate Design

Rate Design Principles

PUC Staff: Andy Bahn

In setting rates, the Commission should note that rates must be just and reasonable and an important aspect of reasonable rates is their design. Also, rate design is largely a quasi-legislative function, involving policy decisions. The ALJ noted that a key purpose of rate design is to determine which customer classes should pay the costs that are reflected in the revenue deficiency and what kinds of rates should be used to recover those costs. As noted by the Department, in past rate cases the Commission has relied on the following four principles in establishing reasonable rate design:

- Rates should be designed to allow the Company a reasonable opportunity to recover its revenue requirement, including the cost of capital;
- Rates should promote the 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 and understanding helps ensure that customers have a better understanding about their utility bills

Minnesota statutes require that rates should be reasonable and not unreasonably discriminatory. Rates cannot unreasonably discriminate either by class or by person. In addition, Minnesota statutes require the Commission to set rates to encourage energy conservation and renewable energy use, "[t]o the maximum reasonable extent." Finally, Minnesota statutes require that "any doubt as to reasonableness should be resolved in favor of the consumer."

The relevant provisions guiding the Commission's establishment of utility customer rates are set forth in Minn. Stat. §§ 216B.03 and 216B.07. Section 216B.03 provides:

> Every rate made, demanded, or received by any public utility, or by any two or more public utilities jointly, shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers. To the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05. Any doubt as to reasonableness should be resolved in favor of the consumer. For rate-making purposes a public utility may treat two or more municipalities served by it as a single class wherever the populations are comparable in size or the conditions of service are similar.

Similarly, § 216B.07 provides:

> 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 to these statutory guidelines for setting rates, the Commission uses its quasi-legislative authority to establish rates for different customer classes.

Class Revenue Apportionment

PUC Staff: Andy Bahn

Statement of the Issue

Should the Commission approve the class revenue apportionment agreed to by MERC and the Department and recommended by the ALJ?

Background

As a distribution utility of natural-gas service, MERC offers both Sales and Transportation service. Sales service customers receive a fully bundled service from MERC. MERC procures wholesale natural gas, interstate pipeline transportation and distributes and resells gas to sales service customers. Sales service customers consist primarily of residential, small and large commercial and industrial customers. Transportation customers are customers that acquire their own gas supplies via unregulated gas suppliers and procure their own pipeline transportation to MERC's town border station. MERC delivers this third party gas to the transportation customers' premises through MERC's gas distribution system

MERC offers the following types of Sales Service in its tariff, which is available to towns and to related rural areas supplied by Northern Natural Gas and by Viking Gas Transmission, Great Lakes Gas Transmission, and Centra in MERC's Minnesota Service Area.

1. **General Service** – Applies to customers whose normal requirement does not exceed 1,990 therms on peak day and such service is not subject to curtailment or interruption, with the exception to curtailment by pipeline supplier in compliance with its approved FERC curtailment plan.

    a. *Residential* – Customers taking natural gas for residential use (space heating, cooling, water heating, clothes drying, etc.) through an individual meter in a single family dwelling or building, or for residential use in an individual flat or apartment, or in a mobile home, or for residential use in not over four households served by a single meter in a multiple family dwelling.
    b. *Small Commercial & Industrial* – 1,500 therms or less per year.
    c. *Large Commercial & Industrial* – over 1,500 therms per year.

2. **Small Volume Interruptible Service** –Applies to gas service which is subject to interruption at any time upon order of MERC for customers whose daily consumption does not exceed 199 dekatherms on any day. Customer must have and maintain both the proven capability and adequate fuel supplies to use alternative fuel if MERC's service to such customer is interrupted. Customer must demonstrate that it has such capability and fuel supplies.

3. **Small Volume Joint Service –** Small Volume Interruptible customer have the option to obtain joint gas service consisting of a base of firm gas volume, supplemented by interruptible volumes not to exceed 199 dekatherms per day.

4. **Large Volume Interruptible Service –** Applies to gas service which is subject to interruption at any time upon order of MERC for customers that take 200 dekatherms or more per day at least once in a calendar year and who maintain both the proven capability and adequate fuel supplies to use alternative fuel if MERC's service to such customer is interrupted. Customer must demonstrate that it has such capability and fuel supplies.

5. **Large Volume Joint Service** – Large Volume Interruptible customer have the option to obtain joint gas service consisting of a base of firm gas volume, supplemented by interruptible volumes which must be 200 dekatherms or more per day at least once in a calendar year.

6. **Super Large Volume Joint Service** – This service is only available to large volume mainline customers supplied through Northern Natural Gas Company and may apply to joint gas service consisting of a base of firm gas volume, supplemented by additional interruptible gas volumes authorized from day to day. Customer must have capacity to take 4,000 dekatherms or more per day and annual consumption of 1.2 Bcf (1,200,000 dekatherms), except that, where consumption falls below this level due exclusively to efforts to conserve energy, or temporarily due to a strike or shutdown, customer is still eligible to take service under this tariff. Customer must document conservation efforts to justify consumption below 1,200,000 dekatherms.

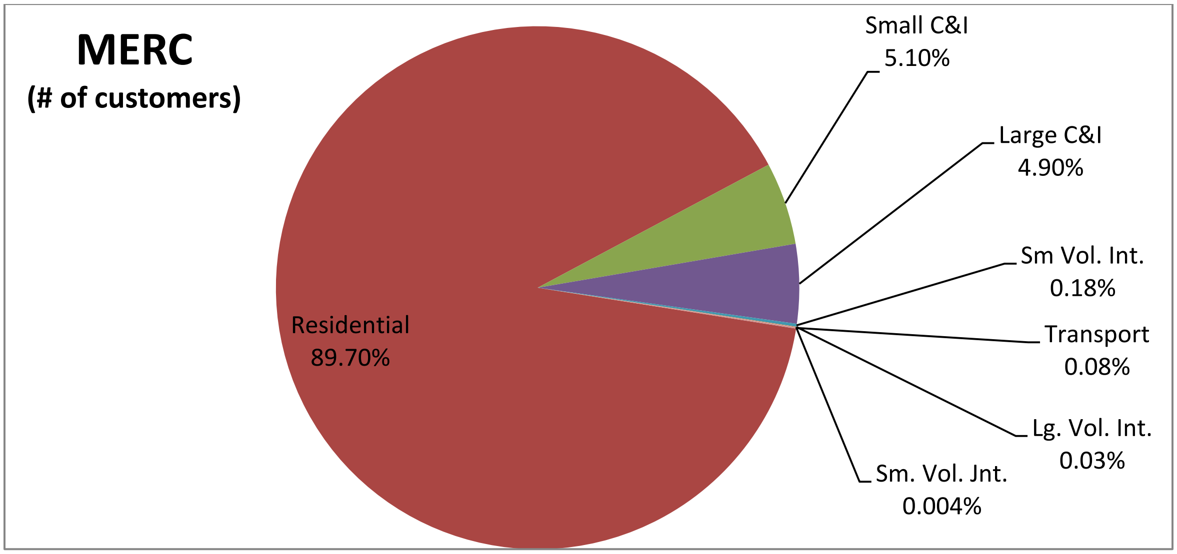
MERC also offers Transportation Service to any non-general service end-use customer who purchases gas supplies that can be transported on a firm or interruptible basis by MERC. Transportation service is offered to customers contingent upon adequate interstate pipeline system capacity and is not available to general service customers. Transportation service is provided on a firm basis only if the customer has arranged firm transportation for such gas supplies on the interstate pipeline serving Company's distribution system and the customer has provided to Company a joint affidavit confirming this signed by the customer and, if applicable, the marketer.

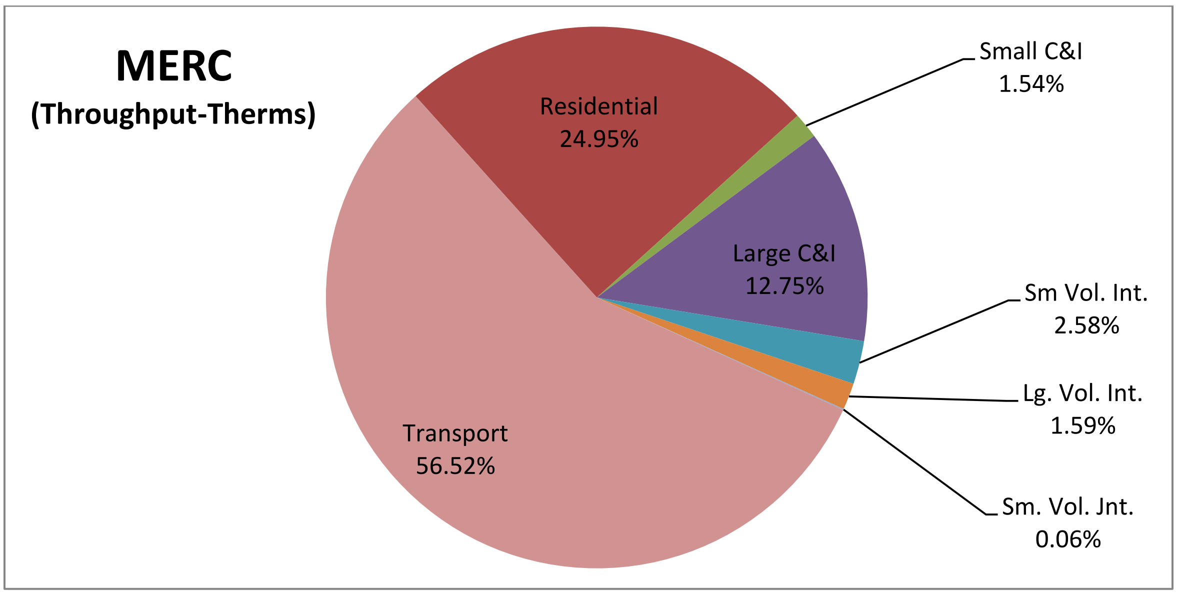
Transportation customers, if otherwise qualified for the rate, may choose transportation service from one of the following classes:

1. **Small Volume Interruptible Service** – Transportation customers whose maximum daily requirements are less than 200 dekatherms.

2. **Large Volume Interruptible Service** – Transportation customers whose maximum daily requirements equal or exceed 200 dekatherms.
3. **Small Volume Joint Firm/Interruptible Service** – Transportation customers taking natural gas service consisting of a base of firm gas volumes supplemented by interruptible gas volumes whose maximum daily requirements, both firm and interruptible, are less than 200 dekatherms.
4. **Large Volume Joint Firm/Interruptible Service** – Transportation customers taking natural gas service consisting of a base of firm gas volumes supplemented by interruptible gas volumes whose maximum daily requirements, both firm and interruptible, equal or exceed 200 dekatherms.
5. **Super Large Volume Interruptible Service** – Available to large volume transport customers served by Northern Natural Gas (NNG) or by Viking Gas Transmission or Great Lakes Gas Transmission within two (2) miles of an alternate supply source. Customer must have capacity to take 1,666 dekatherm or more per day and annual consumption of .5 Bcf (500,000 dekatherm), except that, where consumption falls below this level due exclusively to efforts to conserve energy, or temporarily due to a strike or shutdown, customer is still eligible to take service under this tariff. Customer must document conservation efforts to justify consumption below .5 Bcf.
6. **Super Large Volume Joint Firm/Interruptible Service** - Super Large Volume Interruptible customer has the option to obtain joint gas service consisting of a base of firm gas volume, supplemented by interruptible volumes.
7. **Flexible Rate Gas service –** Available to any non-general-service customer. Flexible rate service is limited to customers subject to effective competition. ("Effective competition" means that a customer who either receives interruptible service or whose daily requirement exceeds 50 dekatherm maintains or plans on acquiring the capability to switch to the same, equivalent or substitutable energy supplies or service, except indigenous biomass energy supplies composed of wood products, grain, biowaste, or cellulosic materials, at comparable prices from a supplier not regulated by the Commission.) A customer whose only alternative source of energy is gas from a supplier not regulated by the Commission and who must use the Company's system to transport the gas is not eligible for flexible rate service. However, customers who have or can reasonably acquire the capability to bypass the Company's system are eligible to take service under flexible tariffs.
8. **Transportation for Resale –** Available to Northwest Natural Gas and other "Transportation for Resale" customers with similar cost characteristics, i.e., customers for whom the cost of providing service is approximately equal to that of Northwest Natural Gas. MERC has one customer using this rate – the town of Ogilvie, Minnesota, where the distribution system is owned by Northwest Natural Gas. Northwest transports its gas supplies through the existing MERC system to provide service to Ogilvie.

90% of MERC's customers are residential customers and less than one tenth of one percent of customers are transportation customers. However, transportation accounts for 56% of MERC's volume of throughput (or volumes of gas moved) on MERC's distribution system for natural gas and residential sales account for only 25% of MERCs sales.





MERC has approximately 192,600 residential customers compared to 168 transportation customers. MERC's residential customers account for sales of approximately 165.5 million therms and transportation customers are responsible for approximately 375 million therms. Customers are divided further within two rate areas (MERC-NNG and MERC-Consolidated).

MERC's Proposed Class Revenue Apportionment

The following table contains MERC's initial proposed apportionment of each customer class' responsibility for MERC's revenue requirements under current and proposed rates as well each customer class' proposed dollar amount and percentage increase. Columns two and three, customers and sales in therms, represented MERC's initial sales forecast in this case.

MERC Customer Class	# of Customers	Sales Therms	Current Revenue	Proposed Revenue	Proposed Increase ($)	Proposed Increase (%)
Residential	192,586	165,401,857	155,031,326	165,926,460	10,895,134	7.03%
Small C&I	10,959	10,197,153	10,036,113	10,934,066	897,953	8.95%
Large C&I	10,513	84,534,106	70,398,482	71,528,985	1,130,503	1.61%
Sm. Vol. Int.	389	17,126,938	10,307,647	10,446,301	138,654	1.35%
Lg. Vol. Int.	68	10,537,913	5,290,795	5,434,443	143,648	2.72%
Sm. Vol. Joint	8	392,300	241,948	245,720	3,772	1.56%
Transport	168	374,643,410	$5,884,408	6,858,027	$979,207	16.64%
Total	214,691	662,833,677	257,186,463	271,374,002	14,187,539	5.52%

Please note that the proposed rate increases for transportation service may appear relatively high compared to the increases for sales service on a percentage basis in the table above. The reason for this is that transportation revenue numbers do not include the cost of gas which reduces the size of the current revenue number for transportation service that is the basis for the percentage increase calculation. The following table reflects the apportionment of each class if the cost of gas is excluded from the revenue numbers.

MERC Customer Class	Total Revenue		Proposed Increase	
	Current	Proposed	($)	(%)
Residential	$52,317,255	$63,212,368	$10,895,113	20.83%
Small C&I	$3,795,889	$4,693,828	$897,940	23.66%
Large C&I	$18,674,673	$19,805,205	$1,130,532	6.05%
Sm Vol. Int.	$2,523,705	$2,662,404	$138,699	5.50%
Lg. Vol. Int.	$518,793	$662,470	$143,678	27.69%
Sm. Vol. Jnt.	$64,890	$68,661	$3,772	5.81%
Transport	$5,884,408	$6,863,615	$979,207	16.64%
TOTAL	**$83,779,612**	**$97,968,553**	**$14,188,941**	**16.94%**

MERC proposed to allocate the rate increase among the rate classes as shown in the table below. The numbers in this table do not include the cost of gas and use MERC's CCOSS as a starting point, but with modifications for the effects of non-cost factors.

MERC Customer Class (Does not include the cost of gas)	**MERC Initial Current Revenue**	**% of Total**	**MERC Initial Proposed Revenue**	**% of Total**
Residential	$52,317,323	**62.45%**	$63,212,457	**64.53%**
Small C&I	$3,795,947	**4.53%**	$4,693,900	**4.79%**
Large C&I	$18,674,568	**22.29%**	$19,805,070	**20.22%**
Sm Vol. Int.	$2,523,255	**3.01%**	$2,661,909	**2.72%**
Lg. Vol. Int.	$518,268	**0.62%**	$661,915	**0.68%**
Sm. Vol. Jnt.	$64,890	**0.08%**	$68,662	**0.07%**
Transport	$5,880,152	**7.02%**	$6,858,027	**7.00%**
Total	**$83,774,403**	**100.00%**	**$97,961,940**	**100.00%**

Position of the Parties

The Department evaluated MERC's proposed apportionment of revenue responsibility by comparing the current and proposed revenues with the results of the CCOSS in order to determine which customer classes are substantially below their respective cost of service, and which classes are expected to contribute revenues in excess of their cost of service. In addition, the Department reviewed the proposed revenue responsibilities from customer classes with bypass or alternative fuel options to ensure that the rates and revenue responsibilities remain competitive with the available alternatives.

The Department was concerned that the proposed increases for the Residential and Small Commercial and Industrial sales classes were significant compared to the overall proposed increase requested by the Company, which could result in rate shock. Therefore, the Department recommended mitigating the increases to the Residential and Small Commercial and Industrial sales classes slightly. The Department recommended moving the percentage of revenue responsibilities apportioned to these classes to the mid-point between the current and MERC proposed apportionment. The Department's proposed revenue apportionment is given in the table below.

MERC Customer Class	MERC Initial Current Revenue	% of Total	DOC Proposed Revenue	% of Total	% Increase
Residential	$155,031,326	60.28%	$164,754,999	60.71%	6.27%
Small C&I	$10,036,113	3.90%	$10,761,908	3.97%	7.23%
Large C&I	$70,398,482	27.37%	$72,545,853	26.73%	3.05%
Sm Vol. Int.	$10,307,647	4.01%	$10,594,807	3.90%	2.79%
Lg. Vol. Int.	$5,290,795	2.06%	$5,511,700	2.03%	4.18%
Sm. Vol. Jnt.	$241,948	0.09%	$249,214	0.09%	3.00%
Transport	$5,880,152	2.29%	$6,955,521	2.56%	18.29%
Total	**$257,186,463**	**100.00%**	**$271,374,002**	**100.00%**	**5.52%**

The Department's rationale for the reasonableness of its initial proposal was that its apportionment continued to move the Residential and Small Commercial and Industrial classes closer to cost, albeit in a slightly smaller increment than that proposed by MERC, while at the same time, maintaining the general contribution of the Transport classes to MERC's overall revenue requirement which should prevent bypass.

When not including the cost of gas, the Department's initial proposed revenue apportionment was as follows:

MERC Customer Class (Does not include the cost of gas)	MERC Initial Current Revenue	% of Total	DOC Proposed Revenue	% of Total	% Increase
Residential	$52,317,323	62.45%	$62,040,996	63.37%	18.59%
Small C&I	$3,795,947	4.53%	$4,521,742	4.62%	19.12%
Large C&I	$18,674,568	22.29%	$20,821,938	21.27%	11.50%
Sm Vol. Int.	$2,523,255	3.01%	$2,810,415	2.87%	11.38%
Lg. Vol. Int.	$518,268	0.62%	$739,172	0.76%	42.62%
Sm. Vol. Jnt.	$64,890	0.08%	$72,156	0.07%	11.20%
Transport	$5,880,152	7.02%	$6,955,521	7.10%	18.29%
Total	**$83,774,403**	**100.00%**	**$97,961,940**	**100.06%**	**16.94%**

MERC accepted the Department's proposed apportionment of revenue responsibility with some modifications. MERC recommended maintaining its proposed rates for the Super Large Volume customer class and Flex customer class because these customer classes are very cost-sensitive with the capability of leaving MERC's system entirely. In addition, MERC adjusted apportionment of revenue responsibility to reflect the Department's proposed updated sales forecast. In order to reflect the Department's proposed revenue apportionment and keep distribution rates the same for similar sales and transportation customer groups, MERC proposed to group customers with the same distribution rates together for revenue apportionment purposes. MERC's proposed revenue apportionment was summarized in MERC witness, Greg Walters Rebuttal Testimony and showed the following.

MERC Customer Class	MERC Rebuttal Current Revenue	% of Total	MERC Rebuttal Proposed Revenue	% of Total	% Increase
Residential	$175,958,238	59.04%	$184,724,487	59.55%	4.98%
Small C&I	$11,515,567	3.86%	$12,147,510	3.92%	5.49%
Large C&I	$80,569,181	27.03%	$82,571,602	26.62%	2.49%
Sm Vol. Int.	$15,474,745	5.19%	$15,198,327	4.90%	-1.79%
Lg. Vol. Int.	$8,090,950	2.71%	$8,260,207	2.66%	2.09%
Sm. Vol. Jnt.	$293,574	0.10%	$289,632	0.09%	-1.34%
Transport	$6,123,366	2.05%	$6,993,245	2.25%	14.21%
Total	**$298,025,621**	**100.00%**	**$310,185,010**	**100.00%**	**4.08%**

When not including the costs of gas, the MERC's current and proposed apportionment of revenue responsibility from its rebuttal testimony was as follows.

MERC Customer Class (Does not include the cost of gas)	MERC Rebuttal Current Revenue	% of Total	MERC Rebuttal Proposed Revenue	% of Total	% Increase
Residential	$53,147,831	61.99%	$61,914,079	63.24%	16.49%
Small C&I	$3,874,651	4.52%	$4,506,595	4.60%	16.31%
Large C&I	$18,863,151	22.00%	$20,865,572	21.31%	10.62%
Sm Vol. Int.	$3,056,324	3.56%	$2,779,906	2.84%	-9.04%
Lg. Vol. Int.	$610,058	0.71%	$779,317	0.80%	27.74%
Sm. Vol. Jnt.	$64,890	0.08%	$60,948	0.06%	-6.07%
Transport	$6,123,366	7.14%	$6,993,245	7.14%	14.21%
Total	**$85,740,271**	**100.00%**	**$97,899,662**	**100.00%**	**14.18%**

The Department accepted the Company's apportionment of revenue responsibility with these modifications. The Department agreed that some of MERC's customers, i.e. the Super Large Volume and Flexible Rate customers, are the most sensitive to a rate increase since they can easily bypass MERC's system if the price charged for natural gas service is not competitive. Interruptible customers have the ability to use alternate fuels, and therefore could choose an alternative should the price of natural gas service become non-competitive relative to the price of alternative fuels. The Department appreciated the ability of Super Large Volume and Flexible Rate customers to leave MERC's system in the face of a cost increase. Consequently, the Department agreed with MERC's proposal to maintain the distribution rates for Super Large Volume and Flexible Rate customer classes, and agreed with MERC's proposed apportionment of revenue responsibility to customer classes presented in MERC's Rebuttal Testimony.

In addition to addressing concerns about large customers leaving MERC's system, the Department concluded that MERC's proposed class revenue apportionment ensures that distribution rates for similar sales and transportation classes remain the same.

The **OAG** believes that MERC's request to increase the apportionment for the residential class, based on this record, is inequitable because MERC's CCOSS is not accurate. The OAG recommended that any revenue increase be collected using MERC's existing revenue apportionment.

The OAG stated that that under the proposed revenue apportionment agreed to by MERC and the Department, the residential class would pay 96.6% of the cost as determined by the CCOSS and this recommendation is based on a CCOSS that has several technical errors, as determined by OAG. The OAG stated that it believed that a CCOSS that was updated to reflect the inaccuracies identified by the OAG's witnesses would show that residents are very close to paying 100% of costs under MERC's current apportionment and that it would be unreasonable to increase apportionment on the basis of a CCOSS that is unreliable and inaccurate. For this reason, the OAG recommended that there be no change to MERC's existing revenue apportionment.

In addition, the OAG's stated its recommendation is also supported by the Commission's directive to incorporate non-cost factors when designing rates, including among others, the customers' ability to pay, customer acceptance of rates, historical continuity of rates, and the ability of some customer classes to pass costs on to others. According to the OAG, each of these non-cost factors provides further justification for limiting rate increases for the residential and small C&I classes; since the residential class contains many ratepayers who have no ability to pay increased utility costs, such as low income families and seniors living on a fixed income.

The **ALJ** concluded that the revenue apportionment agreed to by MERC and the Department was reasonable and should be adopted in this proceeding. The ALJ stated in finding 660 that MERC's proposed revenue apportionment summarized in Mr. Walters' Rebuttal Testimony, and reflected in attachments SLP-S-1 and SLP-S-2 to Department witness, Ms. Peirce's Surrebuttal Testimony, should be used to determine the final rate design after the Commission has determined the final revenue requirement.

In Exceptions to the Report of the ALJ, **MERC** requested clarification in regard to the impact of the ALJ's CIP recommendation on rate design. Because the revenue apportionment agreed to by MERC and the Department, as recommended by the ALJ, resulted in unintended and unreasonable results when the CCRC (Conservation Cost recovery Charge) is removed from base distribution rates, MERC requested the following clarifications to ALJ Finding 660:

> 660. The revenue apportionment agreed to by MERC and the Department is reasonable and should be adopted in this proceeding. MERC's proposed revenue apportionment summarized in Mr. Walters' Rebuttal Testimony, and reflected in SLP-S-1 and SLP-S-2 to Ms. Peirce's Surrebuttal Testimony, <u>as updated to incorporate the removal of CCRC revenues from base rates</u>, should be used to determine the final rate design after the Commission has determined the final revenue requirement.

In its Report, the ALJ recommended that the CCRC be removed from base distribution rates. MERC ran the rate design model based on the Department's and the ALJ's recommendation to remove CCRC from base rates (ALJ Findings 577 and 582) to determine whether there would be any issues with the proposed revenue apportionment agreed to MERC and the Department with respect to MERC's CIP-exempt customers. MERC concluded that removing the CCRC from base distribution rates and applying the revenue apportionment agreed to with the Department results in 76% increase to rates for MERC's Transport NNG-LVI CIP-exempt customers. Although this reflects the revenue apportionment agreed to by MERC and the Department, MERC stated the resulting impact on CIP-exempt customers is an unintended and unjustified consequence of removing the CCRC from base distribution rates. The detailed revenue apportionment, including the cost of gas, agreed to by MERC and the Department is provided below.

NNG Sales Revenue	MERC Compliance Current Revenue	% of Total	MERC Compliance Proposed Revenue	% of Total	% Increase
NNG Sales					
GS-NNG Residential	$151,571,538	50.86%	$152,195,451	51.11%	0.41%
GS_NNG Small Comm & lnd	$8,768,563	2.94%	$8,816,304	2.96%	0.54%
GS-NNG Lg. Comm & lnd	$63,133,857	21.18%	$62,609,780	21.02%	-0.83%
SVl-NNG	$12,290,222	4.12%	$11,784,444	3.96%	-4.12%
LVl-NNG	$4,897,668	1.64%	$4,910,206	1.65%	0.26%
SVJ-NNG	$106,235	0.04%	$102,295	0.03%	-3.71%
Consolidated Sales					
GS-Consolidated Residential	$24,386,700	8.18%	$24,504,971	8.23%	0.48%
GS-Cons. SC&I	$2,747,004	0.92%	$2,758,042	0.93%	0.40%
GS-Cons. LC&I	$17,435,324	5.85%	$17,310,032	5.81%	-0.72%
SVI- Cons.	$3,184,523	1.07%	$3,062,622	1.03%	-3.83%
LVl-Cons.	$3,193,282	1.07%	$3,197,527	1.07%	0.13%
SVJ-Cons.	$187,339	0.06%	$181,112	0.06%	-3.32%
NNG Transport					
SVl-NNG Transport	$241,650	0.08%	$179,721	0.06%	-25.63%
LVl-NNG Transport- CIP Applicable	$1,242,322	0.42%	$1,291,764	0.43%	3.98%
LVl-NNG Transport - CIP Exempt	**$435,404**	**0.15%**	**$766,638**	**0.26%**	**76.08%**
SVJ-NNG Transport	$177,777	0.06%	$154,569	0.05%	-13.05%
LVJ-NNG Transport	$591,164	0.20%	$617,182	0.21%	4.40%
SLVl-NNG Trans.-CIP Exempt	$776,746	0.26%	$789,976	0.27%	1.70%
SLVl-NNG Trans-Applicable	$83,931	0.03%	$27,347	0.01%	-67.42%
SLVJ-NNG Transport - CIP Exempt	$431,102	0.14%	$433,262	0.15%	0.50%
Transport for Resale	$15,469	0.01%	$16,069	0.01%	3.88%
LVJ-NNG Flex Transport	$339,493	0.11%	$346,033	0.12%	1.93%
LVl-NNG Flex Transport	$253,267	0.08%	$255,667	0.09%	0.95%

NNG Sales Revenue	MERC	% of	MERC	% of	%
Consolidated Transport					
SVl-Cons. Transport	$328,372	0.11%	$256,626	0.09%	-21.85%
LVl-Cons. Transport	$469,449	0.16%	$484,135	0.16%	3.13%
SVJ-Cons. Transport	$104,509	0.04%	$89,666	0.03%	-14.20%
LVJ-Cons. Transport	$221,726	0.07%	$232,029	0.08%	4.65%
SLVl-Cons. Transport - CIP Exempt	$410,985	0.14%	$420,705	0.14%	2.37%
SLVl-Cons. Transport - CIP Applicable					
Totals	**$298,025,621**	**100.00%**	**$297,794,175**	**100.00%**	**-0.08%**

A summary of the revenue apportionment agreed to by MERC and the Department, including the cost of gas, is as follows.

MERC Customer Class	MERC Compliance Current Revenue	% of Total	MERC Compliance Proposed Revenue	% of Total	% Increase
Residential	$175,958,238	59.04%	$176,700,422	59.34%	0.42%
Small C&I	$11,515,567	3.86%	$11,574,346	3.89%	0.51%
Large C&I	$80,569,181	27.03%	$79,919,812	26.84%	-0.81%
Sm Vol. Int.	$15,474,745	5.19%	$14,847,066	4.99%	-4.06%
Lg. Vol. Int.	$8,090,950	2.71%	$8,107,733	2.72%	0.21%
Sm. Vol. Jnt.	$293,574	0.10%	$283,407	0.10%	-3.46%
Transport	$6,123,366	2.05%	$6,361,389	2.14%	3.89%
Total	**$298,025,621**	**100.00%**	**$297,794,175**	**100.00%**	**-0.08%**

When not including the cost of gas, a summary of the revenue apportionment agreed to by the Department and MERC is the following:

MERC Customer Class (Does not include the Cost of Gas)	MERC Compliance Current Revenue	% of Total	MERC Compliance Proposed Revenue	% of Total	% Increase
Residential	$53,147,831	61.99%	$53,890,014	63.02%	1.40%
Small C&I	$3,874,651	4.52%	$3,933,431	4.60%	1.52%
Large C&I	$18,863,151	22.00%	$18,213,783	21.30%	-3.44%
Sm Vol. Int.	$3,056,324	3.56%	$2,428,645	2.84%	-20.54%
Lg. Vol. Int.	$610,058	0.71%	$626,841	0.73%	2.75%
Sm. Vol. Jnt.	$64,890	0.08%	$54,723	0.06%	-15.67%
Transport	$6,123,366	7.14%	$6,361,389	7.44%	3.89%

MERC Customer Class	MERC	% of	MERC	% of	%
Total	**$85,740,271**	**100.00%**	**$85,508,826**	**100.00%**	**-0.27%**

In its compliance filing, MERC proposed an alternative rate design that tempers the impact on CIP-exempt customers resulting from removal of the CCRC from distribution rates. This alternative rate design was presented in Attachment C to MERC's Compliance Filing submitted concurrently with its Exceptions. This proposed rate redesign applies the revenue apportionment agreed to by MERC and the Department assuming that the CCRC revenues are still included in rates and then backs out those CCRC revenues based on usage. This results in an ultimate revenue apportionment that differs from the one that was agreed to but addresses the unintended consequences from removing the CCRC from base distribution rates. The detailed alternative revenue apportionment, including the cost of gas, proposed by MERC is given below.

NNG Sales Revenue	MERC Compliance Current Revenue	% of Total	MERC Compliance Proposed Revenue	% of Total	% Increase
NNG Sales					
GS-NNG Residential	$151,571,538	50.86%	$153,779,031	51.64%	1.46%
GS_NNG Small Comm & lnd	$8,768,563	2.94%	$8,945,609	3.00%	2.02%
GS-NNG Lg. Comm & lnd	$63,133,857	21.18%	$62,534,668	21.00%	-0.95%
SVl-NNG	$12,290,222	4.12%	$11,561,339	3.88%	-5.93%
LVl-NNG	$4,897,668	1.64%	$4,776,007	1.60%	-2.48%
SVJ-NNG	$106,235	0.04%	$100,426	0.03%	-5.47%
Consolidated Sales					
GS-Consolidated Residential	$24,386,700	8.18%	$24,770,098	8.32%	1.57%
GS-Cons. SC&I	$2,747,004	0.92%	$2,800,602	0.94%	1.95%
GS-Cons. LC&I	$17,435,324	5.85%	$17,288,358	5.81%	-0.84%
SVI- Cons.	$3,184,523	1.07%	$3,008,835	1.01%	-5.52%
LVl-Cons.	$3,193,282	1.07%	$3,115,402	1.05%	-2.44%
SVJ-Cons.	$187,339	0.06%	$178,073	0.06%	-4.95%
NNG Transport					
SVl-NNG Transport	$241,650	0.08%	$153,395	0.05%	-36.52%
LVl-NNG Transport- CIP Applicable	$1,242,322	0.42%	$783,200	0.26%	-36.96%
LVl-NNG Transport - CIP Exempt	$435,404	0.15%	$421,764	0.14%	**-3.13%**
SVJ-NNG Transport	$177,777	0.06%	$141,012	0.05%	-20.68%
LVJ-NNG Transport	$591,164	0.20%	$405,175	0.14%	-31.46%
SLVl-NNG Trans.-CIP Exempt	$776,746	0.26%	$789,976	0.27%	1.70%
SLVl-NNG Trans-Applicable	$83,931	0.03%	$27,347	0.01%	-67.42%
SLVJ-NNG Transport - CIP Exempt	$431,102	0.14%	$433,262	0.15%	0.50%
Transport for Resale	$15,469	0.01%	$16,069	0.01%	3.88%
LVJ-NNG Flex Transport	$339,493	0.11%	$346,033	0.12%	1.93%
LVl-NNG Flex Transport	$253,267	0.08%	$255,667	0.09%	0.95%

NNG Sales Revenue	MERC	% of	MERC	% of	%
Consolidated Transport					
SVl-Cons. Transport	$328,372	0.11%	$223,523	0.08%	-31.93%
LVl-Cons. Transport	$469,449	0.16%	$281,996	0.09%	-39.93%
SVJ-Cons. Transport	$104,509	0.04%	$81,312	0.03%	-22.20%
LVJ-Cons. Transport	$221,726	0.07%	$155,105	0.05%	-30.05%
SLVl-Cons. Transport - CIP Exempt	$410,985	0.14%	$420,705	0.14%	2.37%
SLVl-Cons. Transport - CIP Applicable					
Total	**$298,025,621**	**100.00%**	**$297,793,989**	**100.00%**	**-0.08%**

A summary of the alternative revenue apportionment proposed by MERC, including the cost of gas, is as follows:

MERC Customer Class	MERC Compliance Current Revenue	% of Total	MERC Compliance Proposed Revenue	% of Total	% Increase
Residential	$175,958,238	59.04%	$178,549,129	59.96%	1.47%
Small C&I	$11,515,567	3.86%	$11,746,211	3.94%	2.00%
Large C&I	$80,569,181	27.03%	$79,823,026	26.80%	-0.93%
Sm Vol. Int.	$15,474,745	5.19%	$14,570,174	4.89%	-5.85%
Lg. Vol. Int.	$8,090,950	2.71%	$7,891,409	2.65%	-2.47%
Sm. Vol. Jnt.	$293,574	0.10%	$278,499	0.09%	-5.13%
Transport	$6,123,366	2.05%	$4,935,541	1.66%	-19.40%
Total	**$298,025,621**	**100.00%**	**$297,793,989**	**100.00%**	**-0.08%**

When not including the cost of gas, the alternative revenue apportionment proposed by and MERC is the following:

MERC Customer Class	MERC Compliance Current Revenue	% of Total	MERC Compliance Proposed Revenue	% of Total	% Increase
Residential	$53,147,831	61.99%	$55,738,721	65.18%	4.87%
Small C&I	$3,874,651	4.52%	$4,105,295	4.80%	5.95%
Large C&I	$18,863,151	22.00%	$18,116,995	21.19%	-3.96%
Sm Vol. Int.	$3,056,324	3.56%	$2,151,753	2.52%	-29.60%
Lg. Vol. Int.	$610,058	0.71%	$410,518	0.48%	-32.71%
Sm. Vol. Jnt.	$64,890	0.08%	$49,815	0.06%	-23.23%
Transport	$6,123,366	7.14%	$4,935,541	5.77%	-19.40%
Total	**$85,740,271**	**100.00%**	**$85,508,638**	**100.00%**	**-0.27%**

The Department concluded that MERC's revenue apportionment and rate design compliance schedules comply with the ALJ's Order. The Department agreed with MERC that since the apportionment percentages did not reflect the change in recovery of CIP costs, apportioning the revenue requirement without adjusting for change in recovery of CIP costs resulted in a 76 percent rate increase for the LVI-CIP Exempt customers on the Northern system. Further the Department acknowledged that in order to more reasonably apportion the revenues to these customers, MERC apportioned its revenue requirement prior to the elimination of the CCRC revenues, and then subtracted out the CCRC revenues from affected classes to calculate the final class revenue requirement. The Department concluded that this approach is a reasonable methodology for apportioning the revenue requirement in this proceeding without unduly burdening one class. Finally, the Department noted that if the Commission approves the proposal to move recovery of CIP costs to the CIP tracker, this issue should not return in future MERC rate cases, since the apportionment percentages will reflect that CIP costs are recovered entirely in the CIP tracker.

In its Exceptions to the ALJ Report, the **OAG** stated that it believes it is unreasonable to modify the apportionment structure on the basis of a CCOSS that the OAG has demonstrated is flawed. In addition to disagreeing with the ALJ's recommendation, the OAG took exception to the ALJ's report because the report does not include a discussion or an acknowledgement of the OAG's recommendation. The OAG stated that the purpose of the ALJ's report and recommendation is to describe what took place during the proceeding and present the recommendations of the various parties to the Commission. The OAG noted that the ALJ did not represent the OAG's recommendation or the reasoning behind its position on revenue apportionment. The OAG recommended that additional findings be inserted to represent the OAG's position and reasoning. The OAG believes that these new findings could be inserted following Finding 659.

> <u>660. The OAG recommended that any revenue increase be collected using MERC's existing revenue apportionment. The OAG noted that a CCOSS updated to incorporate the modifications suggested by Mr. Nelson and Mr. Lindell would show that residents are paying close to, or even greater than, 100% of costs under MERC's existing apportionment. For example, incorporating only Mr. Nelson's recommendation about reclassifying the Mains Account would reduce the residential class's cost of service by almost 2.5%, and reduce the revenue deficiency of the residential class by approximately 20%.</u>[323]
>
> <u>661. The OAG also reasoned that the myriad of flaws in MERC's CCOSS indicated that it was not accurate and should not be used for rate setting purposes. In particular, the OAG noted that the flaws it had identified with MERC's CCOSS had a tendency to overstate the costs caused by the residential and small C&I classes</u>.[324]
>
> <u>662. Finally, the OAG identified several non-cost factors that supported using MERC's existing apportionment. The OAG noted that many members of the</u>

[323] OAG Initial Brief, at 58.
[324] OAG Initial Brief, at 58–59.

residential class have a limited ability to absorb rate increases because they are living on a fixed or limited income.

Additionally, the OAG took exception to the ALJ's recommendation because it is unreasonable to modify the apportionment based on a CCOSS that is inaccurate, and recommended that Finding 660 be modified to reflect that any revenue increase should be collected using MERC's existing revenue.

> ~~660~~ 663. The revenue apportionment agreed to by MERC and the Department is ~~reasonable and should be adopted in this proceeding~~ not reasonable because it is based primarily upon a CCOSS that is inaccurate, and because it fails to take into account several noncost factors. ~~MERC's proposed revenue apportionment summarized in Mr. Walters' Rebuttal Testimony, and reflected in SLP-S-1 and SLP-S-2 to Ms. Peirce's Surrebuttal Testimony, should be used to determine the final rate design after the Commission has determined the final revenue requirement.~~ Because MERC has not met its burden of proof to show that its proposed apportionment is reasonable, the ALJ recommends that any revenue increase be collected using MERC's existing revenue apportionment.

Staff Discussion

Staff agrees with the OAG that the Commission's decision on revenue allocation should be based upon a record of what took place during the proceding and the recommendations of the various parties to the Commission. The ALJ report did not include a description of the OAG's position or recommendations on this issue. Staff is not opposed to including the language proposed by the OAG that describes its position under findings 659, 660 and 661 above.

If the Commission is in agreement with MERC that its CCOSS was not flawed, staff believes the revenue allocation agreed upon between MERC and the Department and recommended by the ALJ is reasonable and should be adopted. If, however, the Commission agrees with OAG that the CCOSS was flawed and inaccurate, the Commission may want to consider the OAG's proposed modification to ALJ finding 660 above that any revenue increase be collected using MERC's existing revenue apportionment.

Decision Alternatives—Revenue Allocation

1. Include the OAG proposed language describing its position on revenue allocation after Finding 659 in the ALJ report as follows:

> 660. The OAG recommended that any revenue increase be collected using MERC's existing revenue apportionment. The OAG noted that a CCOSS updated to incorporate the modifications suggested by Mr. Nelson and Mr. Lindell would show that residents are paying close to, or even greater than, 100% of costs under MERC's existing apportionment. For example, incorporating only Mr. Nelson's recommendation about reclassifying the Mains Account would reduce the

residential class's cost of service by almost 2.5%, and reduce the revenue deficiency of the residential class by approximately 20%.[325]

661. The OAG also reasoned that the myriad of flaws in MERC's CCOSS indicated that it was not accurate and should not be used for rate setting purposes. In particular, the OAG noted that the flaws it had identified with MERC's CCOSS had a tendency to overstate the costs caused by the residential and small C&I classes.[326]

662. Finally, the OAG identified several non-cost factors that supported using MERC's existing apportionment. The OAG noted that many members of the residential class have a limited ability to absorb rate increases because they are living on a fixed or limited income.

2. Adopt the proposed revenue allocation agreed upon between MERC and the Department and recommended by the ALJ;

3. Adopt the OAG recommendation that any revenue increase be collected using MERC's existing revenue apportionment; and/or

4. Adopt the OAG recommendation to modify Finding 660 of the ALJ report to read as follows:

~~660~~ 663. The revenue apportionment agreed to by MERC and the Department is ~~reasonable and should be adopted in this proceeding~~ not reasonable because it is based primarily upon a CCOSS that is inaccurate, and because it fails to take into account several noncost factors. ~~MERC's proposed revenue apportionment summarized in Mr. Walters' Rebuttal Testimony, and reflected in SLP-S-1 and SLP-S-2 to Ms. Peirce's Surrebuttal Testimony, should be used to determine the final rate design after the Commission has determined the final revenue requirement.~~ Because MERC has not met its burden of proof to show that its proposed apportionment is reasonable, the ALJ recommends that any revenue increase be collected using MERC's existing revenue apportionment.

(Note: These decision alternatives correspond to alternatives 183 through 186 on the deliberation outline.)

[325] OAG Initial Brief, at 58.
[326] OAG Initial Brief, at 58–59.

Basic Monthly Service Charges

PUC Staff: Andy Bahn

Statement of Issue

Should the Commission approve MERC's proposal for the Basic Monthly Service Charges.

Introduction

MERC proposed increases in the customer charges and delivery charges for all sales service customers. MERC's initial proposed increases to its customer charge is given below.

Sales Service Customer Class (usage in therms)	Basic Charge (per month)		
	Current	Proposed	Increase (%)
Residential	$8.50	$11.00	29.41%
Small C&I (<1500)	$14.50	$18.00	24.14%
Large C&I (>=1500)	$35.00	$45.00	28.57%
Sm Vol. Int. (Peak Day <2000)	$150.00	$165.00	10.00%
Lg. Vol. Int. (Peak Day >= 2000)	$175.00	$185.00	5.71%

MERC also proposed increases in customer charges for transportation service customers. The proposed customer charge for customers receiving transportation service are the same as for the comparable sales service, except there is an additional monthly charge to cover the added administrative costs of providing transportation service. The current administrative charge is $70.00 per metered account for all transportation customers. MERC proposed to increase the administrative charge to $110.00. The total fixed charge for transportation customer, Basic monthly charge plus the administrative charge, is given below.

MERC Transportation Customer Class	Total Fixed Charge (Per Month)		
	Current	Proposed	Increase (%)
Small volume	$220	$275	25.00%
Large volume	$245	$295	20.41%
Super large volume	$370	$460	24.32%

MERC has several customer classes split among small, large, super large volume, resale and flex customers. Each class has a unique delivery charge, and MERC proposed increases in the delivery charges for small and large volume transportation customers, but did not propose a delivery charge increase for the super large volume, resale and flex transportation customers

MERC Transportation Customer Class	**Proposed Increase in Delivery Charge (%)**
Small volume interruptible and joint	3.77%
Large volume interruptible and Joint-CIP applicable	36.04%
Large volume interruptible -CIP Exempt	19.37%
Super large volume, resale and flex	0.00%

Position of the Parties

The **Department** agreed with all of MERC's proposed customer charges with the exception of the Residential class. While the Department generally agreed with MERC that the Residential customer charge should be brought closer to cost, the Department recommended a more modest increase in the Residential customer charge of $1.00, from $8.50 to $9.50 per month.

MERC accepted the Department's recommendation that the residential customer charge be increased to $9.50. MERC stated that an increase in the residential customer charge to $9.50 per month appropriately assigns costs to the residential class and avoids rate shock. MERC stated that the increased customer charge agreed to by MERC and the Department will result in less variability between winter and summer bills, provide a more accurate price signal to customers by bringing their rates closer to the true cost of service and incrementally stabilize MERC's cash flow. MERC stated further that because there are fixed costs imposed by customers on the Company's system regardless of usage, it is reasonable and appropriate to recover at least some of those fixed costs through a customer charge. MERC stated that in the absence of such an approach, other customers would be required to subsidize the cost of the infrastructure to deliver, monitor, and bill the energy to customers who use little natural gas but remain connected to the system.

In addition, MERC stated its proposed increase to the customer charges for larger customers is supported by the CCOSS and the Commission should adopt the proposed customer charges, as agreed to by MERC and the Department. MERC proposed to increase the customer charges for its larger customers, including the Small Commercial and Industrial ("C&I"), Large C&I, Small Volume Interruptible ("SVI"), Large Volume Interruptible, and Super Large Volume customers. MERC also proposed a monthly charge of $350.00 for the Super Large Volume Town Plant Transportation rate class, and to increase the transportation administration fee from $70.00 to $110.00 per metered account. MERC stated that the CCOSS showed the actual administrative costs to be $110.11 and no party provided testimony regarding MERC's proposal to increase the transportation administration fee from $70.00 to $110.00.

The **OAG** recommended retaining the existing residential customer charge of $8.50 and the existing Small C&I customer charge of $14.50. The **OAG** recommended that any increase in the residential class required revenues should be recovered through the variable per therm rate, rather than an increased customer charge. The OAG stated that MERC's proposal to increase its customer charge from $8.50 to $9.50 for the residential class, and from $14.50 to $18.00 for the small C&I class would set MERC's customer charge at the highest level that ratepayers in the state of Minnesota have ever seen. The OAG recommended that the ALJ and the Commission reject MERC's proposal and make no change to the customer charge.

The OAG stated that holding the customer charge stable will allow the ratepayers to retain personal control over a larger portion of their utility bills and will contribute to the Commission's directive to maximize energy conservation by increasing consumers' incentive to conserve. According to the OAG, residents lose out on the ability to control their utility bills with increased charges, because each time the customer charge is increased, customers give up more control over their bills and this concern is particularly significant for customers who are living on a low or fixed income.

In response to MERC position that an increased customer charge is important to guarantee the utility's revenue stability, the OAG stated that MERC's revenue is already guaranteed by the company's full decoupling mechanism. The OAG concluded that the customer charge has no effect on MERC's revenue stability because its revenue is already fully stabilized through its decoupling mechanism.

In response to MERC claims that an increased customer charge will benefit ratepayers by leveling winter and summer bills, the OAG stated that MERC has already fully accomplished this goal by providing an even payment plan as required by statute. Therefore, according to the OAG, customers have access to a completely levelized monthly bill if they want it.

The OAG stated further that a low customer charge sends a stronger conservation signal to consumers and keeping the customer charge at the same level achieves the Commission's important directive to "encourage energy conservation" by increasing the incentive to conserve. The OAG stated that ratepayers can always reduce their monthly bills by reducing consumption. But that incentive is reduced when the customer charge is allowed to continually increase. In contrast, when the customer charge is kept stable, customers have a greater incentive to conserve, since each dollar spent on conservation will have a comparatively greater effect on customer bills.

MERC stated that its proposed residential and Small C&I customer charge is below the actual cost of services for the those classes, according to the results of its CCOSS and because the customer charges are below the customer cost, it is necessary to recover the unrecovered customer costs through the distribution charge. Therefore, MERC stated customers with higher than average usage pay more than their proportional share of these costs.

MERC stated that contrary to the OAG's assertion that MERC proposes to collect the majority of its fixed costs from residential customers through the monthly customer charge, a $9.50 monthly customer charge would only recover 37% of MERC's fixed costs, as determined in MERC's CCOSS.

MERC stated that its proposed increases to the customer charges are reasonable and further valid rate design goals. MERC stated further that the customer charges serve two main functions: (1) to help stabilize utility revenues and reduce the risk that the utility will over or under recover its revenue requirement due to weather-related fluctuations in gas usage and sales; and (2) to ensure that each customer bears responsibility for a certain level of the utility's fixed costs regardless of usage.

MERC acknowledged that the Commission has recognized that a significant increase in the customer charge can act as a disincentive to conservation, however MERC stated the increases in customer charges it has proposed would not be so significant to have such an impact.

Finally, MERC states that it does not have full decoupling for Residential and Small C&I customers. MERC states that its decoupling mechanism is a use per customer calculation and includes a 10% symmetrical cap on distribution revenues, which only applies to distribution revenues less the CCRC, therefore MERC concludes its decoupling mechanism is not full decoupling.

In response to MERC claims that it does not have a full decoupling program, the **OAG** noted the Commission described MERC's decoupling mechanism in its last rate case as "…a full decoupling mechanism because the true-up amount is based on deviations from forecasted revenue for any reason, including weather, that differs from forecasted amounts."

The **ALJ** recommended that the Commission approve MERC's proposal to increase the residential customer charge to $9.50 per month. The ALJ found that an increase in the residential customer charge to $9.50 per month would move the residential customer charge closer to cost, reduce intra-class subsidies and not result in rate shock.

Further, the ALJ found that that MERC's proposed increase to the customer charges for larger customers, including its proposal to increase the transportation administration fee is supported by the CCOSS. Therefore the ALJ also recommended that the Commission should adopt the proposed customer charges, as agreed to by MERC and the Department.

The ALJ concluded that because the customer charges for residential service are below the customer cost and unrecovered customer costs are now recovered through the distribution charge, customers with higher than average usage (and, in many instances, limited ability to reduce the amount of gas they consume) pay more than their proportional share of these costs.

In addition, the ALJ found that a higher customer charge has a leveling effect upon winter and summer bills, provides better price signals to those customers who can respond to price signals, brings rates closer to the true cost of service, and provides incrementally more stable cash flow to the utility.

Further, the ALJ found that MERC does not have full decoupling for Small Commercial and Industrial customers. The ALJ stated that MERC's decoupling mechanism, which only applies to distribution revenues less the CCRC, is a use-per-customer calculation and that the decoupling mechanism includes a 10 percent symmetrical cap on distribution revenues.

Specifically, the ALJ's findings in regard to customer charges are given below:

Residential Customer Charge

662. MERC's existing residential customer charge is $8.50 per month.

663. MERC initially proposed to increase the monthly residential customer charge to $11.00 per month.

664. Arguing that Residential customers were in "a state of fatigue after three rate cases and continued increases in customer charges since 2007," OAG-AUD urged retaining the existing residential customer charge in the new rates.

665. As the OAG-AUD reasoned, any increase in the residential class required revenues should be recovered through the variable per therm rate rather than an increased customer charge.

666. The Department recommended raising the residential customer charge to $9.50 per month. The Department maintained that the increase to $9.50 would move the residential customer charge closer to cost, reduce intra-class subsidies and would not result in rate shock. The Department further asserted that proposed charge is consistent with other residential customer charges for utility service in Minnesota.

667. MERG accepted the Department's recommendation that the residential customer charge be increased to $9.50.

668. Because the customer charges for residential service are below the customer cost, unrecovered customer costs are now recovered through the distribution charge. As a result, customers with higher than average usage (and, in many instances, limited ability to reduce the amount of gas they consume) pay more than their proportional share of these costs.

669. A higher customer charge has a leveling effect upon winter and summer bills, provides better price signals to those customers who can respond to price signals, brings rates closer to the true cost of service, and provides incrementally more stable cash flow to the utility.

670. An increase in the residential customer charge to $9.50 per month would move the residential customer charge closer to cost, reduce intra-class subsidies and not result in rate shock. The Administrative Law Judge recommends that the Commission approve MERC's proposal to increase the residential customer charge to $9.50 per month.

Customer Charges for Larger Customers

671. MERC proposed to increase the customer charges for its larger customers, including the Small-Commercial and industrial (C&I), Large Commercial and Industrial (Large C&I), Small Volume Interruptible (SVI), Large Volume interruptible (LVI), and SLV customers.

672. In addition, MERC proposed a monthly charge for the SLV Town Plant Transportation rate class and increasing the administrative charge from $70.00 to $100.00 for each metered account.

673. Further, MERC proposed to increase the Transportation Administration Fee from $70 to $110.

674. The Department agreed with MERC's proposed changes. The table below shows the customer charges, MERC's proposed customer charges, and the charges agreed upon by MERC and the Department.

	Current Customer Charge	MERC Proposed Customer Charge	Charge Agreed to by MERC and Department
General Service Residential Consolidated Sales	$8.50	$11.00	$9.50
General Service Small Commercial and Industrial Consolidated Sales	$14.50	$18.00	$18.00
General Service Large Commercial and Industrial Consolidated Sales	$35.00	$45.00	$45.00
Small Volume Interruptible Consolidated Sales	$150.00	$165.00	$165.00
Large Volume Interruptible Consolidated Sales	$175.00	$185.00	$185.00
Super Large Volume Town Plant Transportation	$300.00	$350.00	$350.00

675. OAG-AUD recommended no increase to the customer charge for the Small C&I class. It maintained that any increase to the Small Commercial and Industrial customer charge is unnecessary because MERC has “full decoupling”; which assures collection of its fixed costs of providing service.

676. MERC does not have full decoupling for Small Commercial and Industrial customers. MERC's decoupling mechanism, which only applies to distribution

> revenues less the GCRC, is a use-per-customer calculation. The decoupling mechanism includes a 10 percent symmetrical cap on distribution revenues.
>
> 677. The Administrative Law Judge finds that MERC's proposed increase to the customer charges for larger customers, including its proposal to increase the transportation administration fee is supported by the CCOSS. The Commission should adopt the proposed customer charges, as agreed to by MERC and the Department.

The **OAG** took exception to the ALJ's recommendation to increase the customer charge for both residential and small C&I customers. The OAG disagreed with the ALJ's recommendation, and also stated that the ALJ did not fully describe the reasoning presented by the OAG's expert witnesses and brief.

The OAG stated that the ALJ did not describe the OAG's position that increasing the customer charge runs counter to the Commission's statutory requirement to "encourage energy conservation" to the "maximum reasonable extent." The OAG stated again in its exceptions that a lower customer charge will send stronger conservation price signals to customers and help achieve the conservation mandate established by the legislature. Therefore the OAG recommended that a new finding be inserted to represent this position after Finding 665.

> 666. The OAG-AUD also noted that Minnesota Statutes section 216B.03 places on the Commission a statutory requirement to "encourage energy conservation" to the "maximum reasonable extent." According to the OAG-AUD, a comparatively lower customer charge would send a stronger conservation signal to customers.

Further, the OAG stated that the ALJ's discussion of MERC's decoupling program is inconsistent and does not fairly represent the OAG's position. The OAG took exception to Findings 675 and 676, in which the ALJ discusses MERC's decoupling program, being located under the subheading Customer Charges for Larger Customers. The OAG stated that there is no reason to limit the discussion about decoupling to the context of larger customers and recommended that Findings 675 and 676 be moved to the discussion of residential customer charges and located immediately before the ALJ's Finding 666.

In addition, the OAG took specific exception to ALJ Finding 676 because the ALJ incorrectly stated that MERC does not have full decoupling. The OAG stated again in its exceptions that MERC does have full decoupling, as explained in its Initial and Reply Briefs. The OAG explained that MERC's decoupling program is full decoupling, regardless of whether it includes the CCRC, is calculated on a use-per-customer basis, or is capped at any particular revenue. Therefore the OAG concludes that Finding 676 is incorrect, and the OAG recommended that it be modified to reflect the fact that MERC does have full decoupling, that the decoupling program stabilizes the company's revenue, and that the revenue stabilization provided by decoupling indicates that the company does not also need to increase the customer charge to stabilize revenue.

> ~~675~~ 667. The OAG-AUD recommended no increase to the customer charge for the Small C&I class. It maintained that any increase to the Small Commercial and Industrial

> customer charge is unnecessary because MERC has "full decoupling"; which assures collection of its fixed costs of providing service.
>
> ~~676~~ 668. As noted by the Commission in MERC's 2010 rate case, MERC does ~~not~~ have full decoupling for Small Commercial and Industrial customers. ~~MERC's decoupling mechanism, which only applies to distribution revenues less the CCRC, is a use-per customer calculation. The decoupling mechanism includes a 10 percent symmetrical cap on distribution revenues.~~ MERC's full decoupling program provides the company with revenue stability, and, as such, the company has less need to increase customer charges in order to stabilize revenue.

Further, the OAG stated that the ALJ failed to acknowledge the OAG's response to the MERC's argument that an increased customer charge leads to level summer and winter bills. In response to MERC's position that a high customer charge has a leveling effect on winter and summer bills, the OAG pointed out in both direct testimony and in brief, that a high customer charge "does not provide customers with any benefits that are not already mandated" by Minnesota law. The OAG stated again in its Exceptions that customers already have access to a levelized monthly bill if they want it, because MERC offers an even payment plan as it is required to do. As such, the OAG also took exception to Finding 669, and recommended that it be modified to reflect the fact that a high customer charge provides no benefit to customers who are interested in a level winter and summer bill. The OAG recommended that Finding 669 be modified to reflect the fact that MERC is provided sufficient revenue stability from its decoupling program, as discussed above.

> 669. MERC argues that a ~~A~~ higher customer charge has a leveling effect upon winter and summer bills, provides better price signals to those customers who can respond to price signals, brings rates closer to the true cost of service, and provides incrementally more stable cash flow to the utility. However, as discussed by the OAG, MERC's customers do not need a high customer charge to gain the benefit of a level winter and summer bill, and MERC gains significant revenue stability through its decoupling program.

Finally, the OAG took exception to the ALJ's recommendation on customer charges. The OAG stated that it appears that the ALJ did not consider the OAG's discussion of the need to encourage energy conservation or the OAG's response to MERC's argument about levelized bills. The OAG also stated it appears that the ALJ did not understand the basic facts of MERC's decoupling program. Given that the ALJ did not take these facts into account, the OAG stated it believed that the ALJ's recommendation is not supported by the record. Therefore the OAG took exception to Finding 670 and Finding 677, and made the following recommendation:

> 670. Increasing the residential customer charge in the manner suggested by MERC would not further the Commission's mandate to encourage conservation to the maximum reasonable extent. Given that MERC has significant revenue stability from its decoupling program, and taking into account the non-cost factors identified by the OAG-AUD, the ALJ recommends that there be no increase to the residential customer charge at this time. ~~An increase in the residential customer charge to $9.50 per month would move the residential customer charge closer to cost, reduce intra-class subsidies and not result in~~

~~rate shock. The Administrative Law Judge recommends that the Commission approve MERC's proposal to increase the residential customer charge to $9.50 per month.~~

677. The Administrative Law Judge finds that MERC's proposed increase to the customer charges for larger customers, including its proposal to increase the transportation administration fee is supported by the CCOSS. The Commission should adopt the proposed customer charges, as agreed to by MERC and the Department, with the exception of small commercial and industrial customers. Given that MERC has significant revenue stability from its decoupling program, and taking into account the non-cost factors identified by the OAG-AUD, the ALJ recommends that there be no increase to the small commercial and industrial customers customer charge at this time.

Staff Discussion

Setting the level of the residential customer charge draws largely on the policy judgments of the Commission. Staff believes that the ALJ's recommendation for increasing the residential customer charge to $9.50 per month may be a reasonable approach, if the Commission agrees with all of the ALJ's findings. Likewise, staff believes the ALJ's finding that MERC's proposed increase to the customer charges for larger customers may be reasonable, if the Commission agrees with the reasoning the ALJ used to justify the finding.

However, staff also believes the Commission may want to consider the OAG's concern for whether the ALJ considered the OAG's discussion of the need to encourage energy conservation, and the OAG's response to MERC's argument about levelized bills, and whether the ALJ understood the basic facts of MERC's decoupling program. In regard to MERC's decoupling program, it is staffs understanding that the Commission understood that it had approved a full decoupling pilot program in the previous rate case and that Finding 676 of the ALJ report may be inaccurate.

Staff also 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 several cost and non-cost factors, which include but are not exclusive to energy conservation. Factors the Commission may consider and balance in setting rates and allocating the resulting revenue increase among customer classes and within a specific customer class 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); and
- Administratively feasible.

Decision Alternatives—Residential Basic Monthly Service Charges

1. Adopt the agreed upon proposal between MERC and the Department and the recommendation by the ALJ to increase the Residential monthly basic customer charge to $9.50; or

2. Adopt the OAG’s recommendation to keep the existing Residential monthly basic customer charge of $8.50 and modify the ALJ report to include the OAG’s proposed language to support this recommendation.

Decision Alternatives—Monthly Fixed Charge for Large Customers

1. Adopt the proposed increases by MERC that were agreed to by the Department and recommended by the ALJ for the monthly fixed charges for these customers;

2. Adopt the proposed increases by MERC that were agreed to by the Department and recommended by the ALJ for the monthly fixed charges for these customers, with the exception of small commercial and industrial customers, whose existing customer charge will remain at its current level. Modify the ALJ report to include the OAG’s proposed language to support this recommendation.

(Note: These decision alternatives correspond to alternatives 187 through 190 on the deliberation outline.)

Joint Rate Service

PUC Staff – Bob Brill

Introduction

MERC's currently effective tariff includes a "joint rate" service offered to all small-volume (SV), large-volume (LV) and super-large-volume (SLV) interruptible sales and transportation customers.

Joint Rate Service can be defined as interruptible sales and transportation customers having the option of switching part or all of their daily requirements from interruptible to firm service for the period of one year, starting on November 1, if the customers provide MERC with ninety days in advance notice and if MERC is able to provide the Joint Rate Service.

Historically, on MERC's system, there have been small-volume sales customers, large-volume and super-large-volume transportation customers who have elected MERC's Joint Rate Service.

Background

In its interim rates briefing papers,[327] PUC staff raised many questions and concerns over MERC's joint rate service. PUC staff requested that the Commission require MERC to provide additional supplemental direct testimony explaining how the joint rate service works, how the joint rate service customers are billed, and if MERC's general sales customers are subsidizing the joint rate service.

In its Order[328] for this rate case, the Commission requested that MERC provide certain information pertaining to its Joint Rate Service in its supplemental direct testimony within 30 days from the Order date.

The Commission ordered the following:

> III. Supplemental Filings
>
> Within 30 days of this Order, the Company shall file the following supplements to its direct testimony:
>
> 3. Supplemental testimony that explains how the Company administers joint rate service and the joint rates in its joint rate tariffs and includes the following:
>
> > a. Examples of different billing scenarios that demonstrate how the joint rates are administered for sales and transportation joint rate customers compared to interruptible sales and transportation customers.

[327] See PUC staff briefing papers dated November 7, 2013 in this docket
[328] November 27, 2013 Commission Order - NOTICE AND ORDER FOR HEARING

b. An explanation of how joint rate customers are charged for the interruptible and firm parts of the service they are taking and any credit MERC may provide to firm (or system) sales customers for the joint rate sales customer's use of MERC's entitlement to upstream firm pipeline capacity.

c. An explanation of the methodology MERC employs for the design of these rates, how all elements of these rates are calculated, how these rates are applied to the joint rate tariffs and to customer bills, and the billing arrangements MERC employs for charging joint rate customers the rates that appear in the joint rate tariff.

MERC – Supplemental Direct

Pursuant to the November 27 Order requirements, MERC submitted its joint rate service responses in its Supplemental Direct testimony filed on December 26, 2013.[329] MERC response provided: 1) examples of how sales and transportation joint service customers are billed, 2) compared monthly calculated bills for firm joint and interruptible service for the same customer, 3) an explanation of how joint rate customers are charged for the interruptible and firm service, (4) how MERC credits firm general sales customers for the joint rate sales customers use of MERC's firm pipeline capacity demand entitlements, and 5) MERC provided an explanation of its methodology that it employs for the joint rate design, a) how all elements of the joint rates are calculated, b) how the joint rates are applied to customer bills, and c) the billing arrangements MERC employs for joint rate customers.

MERC stated that each appropriate current tariff rate sheet references the Joint Rate Service option for interruptible sales and transportation customers.

Joint service gives each interruptible sales or transportation customer the option of converting its interruptible volumes to a specified Maximum Daily Quantity ("MDQ") of ***firm*** gas supply and/or **firm** local distribution service.[330] [331]

To calculate the joint service bill, customers who convert its service to joint pay the ***same distribution charge*** for all of its monthly gas usage and the Daily Firm Capacity (DFC) monthly charge is applied to the customer's chosen firm MDQ. The remaining interruptible service taken by the customer is billed as previously calculated.

The joint service DFC charge for sales customers is comprised of the currently effective DFC rate[332] plus the DFC Tariff Margin rate.[333] MERC states that the DFC charge is designed to

[329] MERC Ex. 41, Walters Supplemental Direct at pp. 3-8 and Exhibit GJW-1

[330] Generally speaking, the customer is converting a portion of its interruptible load to firm (Joint Rate Service)

[331] For metering purposes, a customer who converts a portion or its entire load from interruptible to firm joint rate service, the first gas through the meter is considered firm joint rate service until the gas quantity exceeds the customer's MDQ. After the firm joint rate service MDQ is exceeded, the customer usage is treated as interruptible load.

[332] See currently effective tariff sheet no. 7.07 column E

[333] See currently effective tariff sheet no. 7.07 column D

recover the demand costs associated with the MDQ of gas delivered on a firm basis to an interruptible sales customer electing to receive joint sales service.[334] [335]

The interruptible transportation customer choosing to purchase firm joint gas service for a portion or its entire interruptible transportation volume pays the ***same distribution charge*** for all of its monthly usage. The joint rate transportation customer pays a monthly Daily Firm Capacity (DFC) charge, but the rate includes only the DFC Tariff Margin rate[336] times its chosen firm MDQ.[337] [338]

The sales customer's DFC ***base rate***[339] is calculated in MERC's rate cases as reflected on its currently effective tariff Sheet 7.07.[340] The DFC rate includes an adjustment mechanism similar to MERC's base cost of gas; adjusted in MERC's monthly Purchased Gas Adjustment (PGA) petition. This permits MERC to update its DFC rate monthly, as needed and reflected on the appropriate month's tariff Sheet No. 7.07. The DFC Base Rate is reflected in column A, the PGA DFC Adjustment is in column B, DFC Margin Rate is in column D, Total Tariff Rate w/o Margin is in column E, and Total Tariff rate is in column F for SVI, LVI and Super Large Volume ("SLV") rate classes. The DFC monthly PGA factors are also displayed on tariff sheet nos. 7.03 & 7.04.

Each month through its PGA, MERC credits back to the general sales customers any joint DFC sales revenues collected via the assessment of the current effective DFC Total Tariff Rate w/o Margin rate factor (tariff sheet no. 7.07, column E). The DFC margin revenue for sales customers is credited to FERC account #481, transport revenue is credited to FERC account #489.

MERC states that it DFC calculation methodology used is based upon its primary objectives of rate design,[341] which reflects the results of the class cost of service study ("CCOSS").[342]

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[334] For example, take an interruptible sales customer who desires its first 500 therms of gas they use each day to be delivered on a firm basis; MDQ equals 500. MERC applies its currently effective DFC rate of $1.95620 per therm and its DFC margin rate is $0.2300 per therm to the MDQ to calculate the monthly firm portion of the bill. In this example, MERC would bill the customer 500 therms times $2.1862 for the total monthly firm cost of $1,093.10.
[335] See MERC Ex. 41, Walters Supplemental Direct at Exhibit GJW-1
[336] See currently effective tariff sheet no. 7.07 column D
[337] For example, take a transportation customer who desires the first 500 therms of gas they use each day to be delivered on a firm basis; its MDQ equals 500. MERC applies its currently effective DFC margin rate is $0.2300 per therm for the first 500 therm. MERC would bill the transportation customer 500 therms times $0.23 for a total monthly cost of $115.00. This charge is designed to recover the firm costs associated with the MDQ amount of gas delivered to a transportation gas customer.
[338] See MERC Ex. 42, Walters Supplemental Direct at Exhibit GJW-1
[339] Includes only Non-Margin rate component
[340] The calculation for MERC's DFC base rate reflected in its Base Cost of Gas filing; Docket No. G011/MR-13-732. The calculation for MERC's NNG and Consolidated PGA systems DFC base rates are shown in Exhibit 1, page 2 of Docket No. 13-732. The DFC base rate is calculated by dividing the sum of the total annual demand costs by the total quantity of annual demand contracts, resulting in a monthly per therm rate for each MDQ.
[341] See MERC Ex. 40, Walters Direct pp. 6-28
[342] See MERC Ex. 29, Hoffman Malueg Direct p. 5-31 and MERC Ex. 4, Informational Requirement Document No. 12, Schedule 2, Column D (of each page) and Schedule 4, p. 2, Col. F and G for the calculation of the DFC margin rate within the CCOSS for the proposed 2014 test year

Department

The Department reviewed MERC's joint rate service and concluded that MERC has complied correctly with its tariff and noted that in order to convert from interruptible to joint service the customer must go through MERC's approval process. The approval process starts first with an Engineering review to assure the conversion does not impact firm general sales customers' system capabilities, and then the request is reviewed by the Gas Supply department. After the request review process is complete, it is either granted or deny.

If granted, the joint service firm capacity is administrated through MERC's system reserve margin, thus, no additional interstate pipeline demand entitlements are necessary.

The Department further reviewed MERC's curtailment procedures and concluded that joint service customers will be held to its MDQ, if curtailed.[343] If the curtailment is severe like what was experienced during the 2013-14 heating season, the joint customers will be curtailed before the general sales customers. [344]

The Department concluded that MERC's firm general sales customers do not appear to be subsidizing its joint rate service customers. MERC credits back the non-margin DFC revenues through the PGA, which provides a benefit to all firm general sales customers by lowering the rates.

The Department recommended that the Commission accept MERC's explanation on how it administered its Joint Service and did not recommend any changes to the joint service.

ALJ

In proposed finding 681, ALJ Lipman does discuss MERC's Joint Rate Service, describing the Department's conclusions and recommendations, but ALJ Lipman does not make a recommendation.[345]

PUC Staff Comment

Staff believes that MERC is in accordance with its tariff provisions and has properly administrated its joint rate service. The joint rate service provides MERC's interruptible customers added flexibility. A customer can convert its interruptible sales or transportation volume to MERC's firm joint rate service. Further, by converting to joint service, the customer can limit its curtailment exposure. As discussed above, the joint service is curtailed only after all interruptible service has been stopped and subservient only to general sales.

The joint service conversion from interruptible does provide MERC's firm general sales customers a benefit. The current firm general sales customers pay a monthly demand PGA rate

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[343] In other words, the customer's remaining interruptible capacity would be curtailed while still being able to flow its joint service MDQ.
[344] See Department Ex. 203, Pierce Direct at pp. 20-22 and Attachment SLP-5 – From Docket No. 08-835 Informational Request Number 306 submitted October 10, 2008
[345] See ALJ Report at p. 100-101

which covers the MERC's demand costs; such as interstate pipeline contract costs and hedging costs. As part of the joint service tariff, MERC credits back the non-margin DFC revenues through its PGA, thus providing its general sales customers with lower demand PGA rates.

MERC has calculated its revised Non-Margin DFC charge in Docket No. 13-732 for both MERC-Consolidation and MERC-NMU. The non-margin DFC charge is calculated by dividing the total demand costs by MERC's total demand weighted volume in therms, i.e. annualized demand entitlements.[346] The non-margin DFC charge is applied to each converted joint customer's MDQ as a monthly charge.

Non-Margin DFC charge calculation example

	MERC-Consolidated	MERC-NMU
Demand Costs	$3,733,360	$38,615,474
Demand Volume	6,323,750	19,239,270
Non-Margin DFC Charge	$0.59037	$2.00712

MERC stated, and the Department agreed that by calculating the non-margin DFC revenues and applying those revenues back to the monthly PGA as a credit, the joint customers are paying its fair share for the demand entitlement costs and other demand charges. Thus, the joint customers are not receiving any subsidy from general sales customers.[347, 348]

Pursuant to the November 27 Order, MERC provided in its supplemental direct testimony,[349] billing calculations for both interruptible sales and transportation customers who elect to convert to joint service.

Monthly Bill Comparison for an Interruptible sales customer converting to joint service.

A ***sales*** customer with 6,000 therms per month load converts a portion of its volume to joint service with a MDQ of 50 therms per day. In accordance with its tariff, the first 50 therms each day are treated as firm joint service; anything over 50 therms is interruptible service. MERC's calculated the interruptible customers' bill before conversion to joint service at $3,126.88 and after converting 50 therms per day to joint service at $3,227.24.[350] So for an additional $100.36 per month the customer is assured of receiving 50 therms per day through MERC's firm joint rate service. If interruptible service is curtailed, the customer would continue to receive its firm commitment of 50 therms per day.

Billing Variables

Sales Customer Per Therm	Interruptible with before conversion	Interruptible converted to Joint Service
Monthly Customer Charge	$175	$175

[346] For an example of MERC's calculation, see Docket No. 13-732, Exhibit 1, p. 2 and p. 8
[347] See MERC Ex. 41, Walters Supplemental Direct at p. 4
[348] See Department Ex.203, Pierce Direct at pp. 21-22
[349] See MERC Ex. 41, Walters Supplemental Direct at Exhibit GJW-1
[350] Id.

Distribution Charge	$0.03568	$0.03568
Base Cost of Gas	$0.45630	$0.45630
DFC Charge per MDQ[351]	N/A	$2.00712

Monthly Bill Comparison for an Interruptible transportation customer converting to joint service

Staff Conclusion: For an additional $100.36 per month, the interruptible sales customer receives 50 therm per day of firm service or 1,500 therms assuming a 30 day billing cycle.

A ***transportation*** customer with 6,000 therms per month load converts a portion of its volume to joint service with a MDQ of 50 therms per day. In accordance with its tariff, the first 50 therms each day are treated as firm joint service; anything over 50 therms is interruptible service. MERC's calculated the interruptible customers' bill before conversion to joint service at $459.08 and after converting 50 therms per day to joint service at $470.58. So for an additional $11.50 per month the customer is assured of receiving 50 therms per day through MERC's firm joint rate service. If interruptible service is curtailed, the customer would continue to receive its firm commitment of 50 therms per day.

Billing Variables

Transportation Customer Per Therm	Interruptible with before conversion	Interruptible converted to Joint Service
Monthly Customer Charge	$175	$175
Transportation Administration Charge	$70	$70
Distribution Charge	$0.03568	$0.03568
DFC Charge per MDQ[352]	N/A	$0.23

Staff Conclusion: For an additional $11.50 per month, the interruptible sales customer receives 50 therm per day of firm service or 1,500 therms assuming a 30 day billing cycle.

While PUC staff does not necessity disagree with the Department and ALJ Lipman recommendation to the Commission, it does have concerns about MERC's joint service. PUC staff concerns include the following:

1. MERC's current curtailment hierarchy is deficient by not including a separate curtailment position in the hierarchy for its joint service.[353] PUC staff believes that the Commission may wish require MERC to file a revision to its current tariff's 1st Revised Sheet No. 8.41 that clearly states the joint service curtailment position within the curtailment hierarchy.

2. MERC's joint service is a firm service and PUC staff believes that the service should be treated as such. MERC's current method of charging for the joint service requires the customer to only pay a small demand based premium. PUC staff believes that the joint

[351] Includes both Non-Margin ($1.77712) and Margin ($0.23) DFC charge
[352] Includes Margin ($0.23) DFC charge
[353] See PUC staff discussion on Curtailment rules and practices, herein

service premium does not adequately compensate the general sales customers for its use of demand service such as: interstate pipeline and hedging demand costs. A possibility exist that the joint service customers could be receiving a subsidy from general sales. Staff illustrates its concern as follows:

Table 1: MERC's current billing calculation for sales customers

30 day billing cycle	Billing Variables	General Sales customers with 200 therms a day	Billing Variables	Interruptible load of 200 therms per day converting 50 therms to joint service
Customer Charge		$165.00		$175.00
Distribution Charge				
Monthly therm use	6,000		6,000	
Rate	$0.11048	$662.88	$0.03568	$214.08
Cost of Gas				
Monthly therm use	6,000		6,000	
Rate	$0.73062	$4,383.72	$0.45630	$2,737.80
DFC Charge				
MDQ	N/A		50	
Rate	N/A	$0	$2.00712	$100.36
Total Bill		$5,211.60		$3,227.24

Table 2: MERC's current billing calculation for interruptible sales customers converting to joint service

30 day billing cycle	Billing Variables	Interruptible Sales customer billing	Billing Variables	Interruptible load of 200 therms per day converting 50 therms to joint service	Difference
Customer Charge		$175.00		$175.00	$0
Distribution Charge					
Monthly therm use	6,000		6,000		
Rate	$0.03568	$214.08	$0.03568	$214.08	$0
Cost of Gas					
Monthly therm use	6,000		6,000		
Rate	$0.45630	$2,737.80	$0.45630	$2,737.80	$0
DFC Charge					
MDQ			50		
Rate		N/A	$2.00712	$100.36	$100.36
Total Bill		$3,126.88		$3,227.24	$100.36

Table 3: Proposed Alternative billing calculation for joint service

30 day billing cycle		**Current:** Interruptible load of 200 therms per day converting 50 therms to joint service		**Proposed:** Interruptible load of 200 therms per day converting 50 therms to joint service	Difference
Customer Charge		$175.00		$175.00	$0
Distribution Charge					
Monthly therm use	6,000		4,500		
Rate	$0.03568	$214.08	$0.03568	$160.56	
			1,500		
			$0.11048	$165.72	
Total Distribution		$214.08		$326.28	$112.20
Cost of Gas					
Monthly therm use	6,000		6,000		

30 day billing cycle		**Current:** Interruptible load of 200 therms per day converting 50 therms to joint service		**Proposed:** Interruptible load of 200 therms per day converting 50 therms to joint service	Difference
Rate	$0.45630	$2,737.80	$0.45630	$2,737.80	
			1,500		
			$0.27432	$411.48	
Total Cost of Gas		$2,737.80		$3,149.28	$411.48
DFC Charge					
MDQ	50				
Rate	$2.00712	$100.36		N/A	($100.36)
Total Bill		$3,227.24		$3,650.56	$423.32

PGA Cost of Gas concern: As illustrated in Table 1, a firm general sales customer pays a sufficient premium for the right to receive firm general sales service; primary caused by MERC's distribution charge and PGA demand cost of gas.[354] When an interruptible sales customer converts to firm joint service, the customer is paying a $100.36 DFC premium[355] to receive essentially the privileges as firm service, see Table 2.

The only difference between general sales and joint service is that joint service is curtailed before general sales service. Other than the curtailment hierarchy difference, the joint customer enjoys the same benefits as general sales customers enjoy over interruptible service.

PUC staff believes that MERC's joint sales service is a slightly degraded service because of the curtailment hierarchy, but premium difference between joint and general service customers caused PUC staff to be concerned that the joint customers are possibility receiving a subsidy from the general sales customers for the cost of gas by not paying its fair share, Table 2. As Table 3 illustrates, under MERC's current billing the joint customer would billed $2,737.80 as opposed to PUC staff's alternative billing of $3,149.28. The $411.48 highlights the possibility that the joint customers may be receiving a subsidy from the general sales customers.

Distribution Charge concern: Table 3 further illustrates that the general sales customer are paying a $0.11048 distribution charge, while the interruptible customer pays a $0.03568 distribution charges (Table 1). As previously mentioned the joint service is firm and should be paying for the service as general sales customers. PUC staff believes that the joint service customer should pay the general sales service distribution charge as opposed to the interruptible

[354] The firm general sales customer pays a $0.11048 distribution charge and a $0.73062 PGA demand cost of gas charge as opposed to the interruptible customer who pays $0.03568 and $0.45630, for a $1,984.36 difference
[355] MERC stated that this difference is credited back to its monthly PGA demand cost of gas

charge. In this example, the firm joint customer would be billed the $0.11048 distribution charge for 1,500 therms of firm joint sales, see Table 3. PUC staff believes that the joint service is receiving a further subsidy by paying the interruptible distribution charge. This applies to both joint sales and transportation customers.

As illustrated in Table 3, PUC staff believes that the joint customers are possibility receiving a subsidy from the general sales customers, $423.32 in PUC staff example.[356] PUC staff believes that the Commission may wish to review MERC's joint service rate design more closely, such as opening a separate docket outside this rate case.

Decision Alternatives

1. Adopt the Administrative Law Judge and the Department recommendations to accept MERC's explanation of: (a) how it administers its Joint Service with no suggested changes, and (b) that the joint customers are not receiving a subsidy from another rate class.

2. Adopt PUC staff subsidy concerns regarding MERC's joint service and require MERC and the Department to work together to resolve and address the subsidiary concerns and make a compliance filing within 60 days from the date of the Commission Order in this docket.

3. Adopt PUC staff subsidy concerns regarding MERC's joint service and open an inquiry in a new docket outside the current rate case.

(Note: These decision alternatives correspond to alternative 191, 192 and 193 on the deliberation outline.)

Reference to Record
MERC Ex. 29, Hoffman Malueg Direct at pp. 5-31
MERC Ex. 40, Walters Direct at pp. 6-28
MERC Ex. 41, Walters Supplemental Direct at pp. 3-8 and Exhibit GJW-1
MERC Ex. 4, Informational Requirement Document No. 12, Schedule 2, Column of each page and Schedule 4, p. 2, Col. F and G
Department Ex. 203, Pierce Direct at pp. 20-22 and Attachment SLP-5

[356] See Table 3

Curtailment Rules and Practices

PUC Staff – Bob Brill

Introduction

On January 25, 2014, a major pipeline explosion occurred in Canada which creased deliveries[357] at Emerson and ultimately Viking Gas Pipeline, an interstate pipeline company.[358] As a result of this incident, MERC was forced to curtail all interruptible customers.

On March 5, 2014, Constellation New Energy (Constellation) filed its petition in this rate case questioning MERC's curtailment rules and practices. Constellation questioned MERC's decision to curtail all interruptible customers and requested either confirmation or clarification that gas should be allowed to flow to interruptible customers at any city gate where there are no delivery or pressure problems even though there could be problems downstream at another city gate that would require firm service to be partially curtailed.

PUC Staff believes that Constellation's concerns have been addressed and resolved. PUC staff believes this issue to be uncontested.

[Staff Note: U.S. Energy had similar concerns about MERC's curtailment rules and practices and filed a late intervention petition on February 27, 2014. In its Fifth Prehearing Order, Administrative Law Judge Eric L. Lipman denied U.S. Energy intervention petition on March, 27, 2014.]

Background

MERC's 1st Revised Sheet No. 8.41 list the order of priority for service among its customers; curtailment rules.

<u>Priority of Service</u>
Company will make every reasonable attempt to maintain continuous gas service to customers. The following priorities will be followed when operational and supply conditions require service interruptions with highest priorities listed first:

1. General Service Customers
2. Small Volume Firm
3. Large Volume Firm
4. Small Volume Interruptible
5. Large Volume Interruptible

<u>Curtailment of Service to Interruptible Customers</u>

[357] Partial deliveries at were later restored
[358] This incident caused delivery issues throughout the State of MN for its LDCs

1. Standard Order of Curtailment: When in the opinion of the Company it becomes necessary to curtail or interrupt service to any of the Company's Interruptible Customers, such service shall be interrupted in the following order to protect deliveries to General Service Customers:

First: Large Volume Interruptible Customers.
Second: Small Volume Interruptible Customers.

Company must comply with curtailment plans, orders, definitions and classifications as set out in Federal Energy Regulatory Commission Gas tariffs of wholesale pipeline suppliers and in the rules and orders of regulatory or governmental bodies having jurisdiction.

2. Partial Curtailment: Where curtailment of only part of the deliveries of gas under similar interruptible classification is necessary, all customers under such classification will over a reasonable period of time, be treated alike so far as practicable.

Constellation

Constellation addressed its concerns:[359]

1. over the significant number of Constellation customers who were curtailed in January 2014 as a result of interstate pipeline's OFOs due to inclement weather and distribution pressure problems;

2. that there is no reconciliation between the interstate pipeline and MERC's distribution system for a customer's [upstream] firm capacity purchases; and

3. that MERC's record keeping system does not have sufficient ability to track a customer's brokered volumes that are delivered to the applicable city gate.

Constellation expressed concern that when firm customers are curtailed, all interruptible customers are curtailed. Constellation requested either confirmation or clarification that gas should be allowed to flow to interruptible customers at any city gate where there are no delivery or pressure problems even though there could be problems downstream at another city gate that would require firm service to be partially curtailed.

To address its reconciliation concern, Constellation urged MERC to establish a process for reconciling the amounts that are purchased for firm capacity on the interstate pipeline and the capabilities of MERC's own distribution system. Constellation proposed to the Commission that MERC be required to reconcile these differences between MERC and interstate pipeline. Constellation suggested that if a demand was made by a customer, or a customer's broker, by October 1, MERC would reconcile the capacity differences before the start of the heating season.

[359] See generally, Constellation Ex. 125, Haubensak Direct at pp. 2-3 and Ex. RH-1, Attachments 1-3

Constellation stated that MERC does not have sufficient ability to track a customer's brokered volumes delivered to a city gate. Constellation supported MERC's proposal to install gate station monitoring equipment in this proceeding.

MERC Rebuttal

In its Rebuttal Testimony, MERC addressed Constellation's concerns. MERC explained that Constellation curtailment concern occurred on the weekend of January 25, 2014; a one-time occurrence. The incident was caused by an interstate pipeline rupture in Canada, which threaten loss of service in MERC's territory. Compounding the pipeline rupture issue, Minnesota experienced some of its coldest weather on record during this period. MERC did curtail all interruptible and all joint service customers' gas that weekend in accordance with its tariff.[360]

MERC believes its actions during this curtailment period followed the priority of service as reflected in its current 1st Revised Sheet No. 8.41 tariff sheet. MERC believes that it has the right and obligation to protect the reliability of service to all firm customers pursuant to the tariff requirements.

MERC agreed with Constellation's proposal to reconcile its customers' purchased firm capacity on interstate pipeline to its distribution system with certain modifications. MERC stated that it relies on customers or the customer's broker to provide it with the amount of purchased firm capacity on the interstate pipeline. Constellation has not provided such a list to MERC during the past 2-3 years. MERC would prefer that this be an annual process between MERC and the customers and brokers instead of this occurring only on the demand of the customer or broker. MERC preferred that customers and brokers share this information with MERC no later than August 1 of each year in order for MERC to complete the necessary evaluation of its distribution system prior to the start of the heating season.[361]

Evidentiary Hearing[362]

MERC responded to the issues raised by Constellation in its Direct Testimony regarding curtailment and firm capacity. MERC stated that it and Constellation have had several recent conversations, and MERC believed Constellation was satisfied with MERC's response to their concerns.

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[360] MERC further addressed Constellation's request that MERC either confirm or clarify that gas should be allowed to flow to interruptible customers at any city gate where there are no delivery or pressure problems even though there could be problems downstream at another city gate that would require firm service to be partially curtailed. MERC stated that it would not confirm such a statement. MERC's was responsible for providing safe and reliable service to its general service firm customers. MERC's believes it may be necessary to curtail upstream customers to protect firm service to those downstream, MERC further believes it is its right and obligation to protect the reliability of service to all firm customers pursuant to the tariff requirement. [MERC Ex. 42, Walters Rebuttal at pp. 14-15]

[361] MERC Ex. 42, Walters Rebuttal at pp. 16-17

[362] Evidentiary Hearing Transcript at p. 115

ALJ

In proposed finding 546, ALJ Lipman recommends that formally providing for such a reconciliation service to firm service customers would be a useful addition to MERC's tariff.[363]

PUC Staff Comment

Staff agrees with the ALJ Lipman's recommendations.

Staff believes all issues related to MERC's curtailment rules and practices between MERC and Constellation have been resolved for the purpose of this rate case.

However, as reflected above, MERC's current order of priority for service does not include its Joint Sales and Transportation Services where interruptible customer can elect to convert a portion its interruptible service to firm service; Joint Service. Joint customers do not have the same priority of service rights as General Service customers. The distinguishing difference is that Joint customers are interrupted before General Service customers. Staff believes that if MERC is to continue its Joint Service, the Commission should require MERC to update its order of priority for service to include the Joint Service. This will be further addressed by PUC staff in the Joint Service section of these briefing papers.

Decision Alternatives

1. Adopt the Administrative Law Judge recommendation and approve the reconciliation service for MERC's customers with its customers providing the required data by August 1 of each year. (MERC, Constellation, ALJ)

(Note: This decision alternative corresponds to alternative 194 on the deliberation outline.)

<u>Reference to Record</u>
Constellation Ex. 125, Haubensak Direct at pp. 2-3 and Ex. RH-1, Attachments 1-3.
MERC Ex. 42, Walters Rebuttal at pp. 14-17
Evidentiary Hearing Transcript at p. 115

[363] See ALJ Report at p. 81

General Housekeeping and Compliance Issues

PUC Staff – Bob Harding

All of the compliance filing requirements in the decision alternatives are standard rate case compliance items. These requirements ensure that MERC files various financial and rate design schedules that reflect the Commission's decision, revised tariff sheets, a draft customer notice, and a new base cost of gas. Staff notes that in this case an interim rate refund plan may not be necessary if final rates are higher than interim rates.

Staff also recommends the Commission include a set of financial summaries for MERC in its order in this docket that includes: a schedule showing the calculation of MERC'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.

(Note: The decision items for general housekeeping and the general, thirty-day rate case compliance filing are listed under alternatives 195 through 197 on the deliberation outline.)