STATE OF MINNESOTA

BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota	MPUC DOCKET No. G-011/GR-13-617 OAH Docket No. 8-2500-31126

MINNESOTA ENERGY RESOURCES CORPORATION'S INITIAL BRIEF

JUNE 24, 2014

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I. INTRODUCTION

This Initial Brief is submitted in support of the September 30, 2013 Application by Minnesota Energy Resources Corporation ("MERC" or the "Company") for authority to increase rates for natural gas service provided to retail customers in Minnesota. This Brief focuses on those issues that continue to be contested by other parties to this proceeding. An outline of uncontested issues and an identification of the places in the record where they are addressed have been set forth previously in the Company's Issues Matrix[1] and in MERC's proposed Findings of Fact, Conclusions, and Recommended Order submitted with this Initial Brief. As these filings demonstrate, MERC has worked with the other parties to significantly narrow the issues in this proceeding.

MERC initiated this proceeding on September 30, 2013, seeking a general rate increase of $14,187,597, or approximately 5.52 percent over current rates, in order to cover its cost of furnishing natural gas service to its Minnesota customers. Based on adjustments agreed to during this proceeding, MERC is requesting an annual base rate increase of $12,159,494, or approximately 4.1 percent.[2] As discussed below, MERC's positions on the remaining disputed issues are fully supported by the record in this proceeding, by sound public policy, and are consistent with Minnesota law. The Company respectfully requests that the Administrative Law Judge ("ALJ") and Commission so find, and approve the Company's recommendations on the remaining disputed matters.

II. APPLICABLE LAW

This rate case is governed by Minnesota Statutes Section 216B.16, which sets forth the process to be followed and factors to be considered in setting final rates. Minnesota Statute

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1 MERC Compliance Filing, Issue Matrix (June 6, 2014) (Doc. ID. No. 20146-100192-01).

2 *See* Ex. 42 at Exhibit GJW-1, Schedule 3 (G. Walters Rebuttal and Exhibits).

Section 216B.16 sets forth a summary of the factors that the Commission must consider to determine just and reasonable rates for a public utility:

> The commission, in the exercise of its power under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.[3]

Minnesota's ratemaking statute fits into the overall scheme of utility regulation in the State, which requires the Commission to ensure that the rates of public utilities are "just and reasonable,"[4] allowing utilities recovery of their reasonable operating expenses and a reasonable rate of return on their prudent investments. The Minnesota Supreme Court has explained that this requires "balancing the interest of the utility companies, their shareholders, and their customers to ensure that rates are 'just and reasonable.'"[5]

These state statutory requirements must be interpreted with regard to landmark United States Supreme Court decisions that describe the constitutional tests used to determine the fairness or reasonableness of the rate of return. These tests require that:

1. The rate of return should be similar to that of other financially sound businesses having similar or comparable risks;

2. The rate of return should be sufficient to ensure confidence in the financial integrity of the public utility; and

3. The rate of return should be adequate to maintain and support the credit of the utility, thereby enabling it to attract, on a reasonable cost basis, the funds

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3 MINN. STAT. § 216B.16, subd. 6.

4 MINN. STAT. § 216B.03.

5 *In the Matter of the Request of Interstate Power Co. for Auth. to Change Its Rates For Gas Serv. In Minn.*, 574 N.W.2d 408, 411 (Minn. 1998).

> necessary to satisfy its capital requirements so that it can meet the obligation to provide adequate and reliable service to the public.[6]

In Hibbing Taconite Co. v. Minnesota Public Service Commission,[7] the Minnesota Supreme Court adopted the *Bluefield* and *Hope* tests, declaring:

> Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service, are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[8]

The Minnesota Supreme Court has also held that in order to establish a "reasonable return" or to establish the "cost of service," the facts must be demonstrated by a "preponderance of the evidence."[9]

As demonstrated by the Issues Matrix submitted by MERC in this proceeding, through the course of discovery, testimony, and extensive discussions, the parties to this proceeding have resolved many of the financial issues in this case.[10] Despite MERC's best efforts to work with the parties to narrow the issues in this proceeding, there are several issues that remain. The record demonstrates that MERC has provided a preponderance of evidence to support the Company's financial position on the remaining issues. In order for MERC to have a reasonable opportunity to recover its expenses and to earn a reasonable rate of return on its investments, MERC's positions on these issues should be adopted.

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6 *See Bluefield Water Works & Investment Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) ("Bluefield"); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope").

7 302 N.W.2d 5 (Minn. 1980).

8 *Hibbing Taconite Co. v. Minn. Pub. Serv. Comm'n*, 302 N.W.2d 5, 10 (Minn. 1980) (citing *Bluefield*, 262 U.S. at 690).

9 *In the Matter of the Petition of Minn. Power and Light Co., d/b/a Minn. Power, for Authority to Change its Schedule of Rates in Minn.*, 435 N.W.2d 550, 554 (Minn. Ct. App. 1989) (review denied).

10 MERC Compliance Filing, Issue Matrix (June 6, 2014) (Doc. ID. No. 20146-100192-01).

III. MERC HAS ACCEPTED THE DEPARTMENT'S ALTERNATIVE SALES FORECAST, WHICH IS REASONABLE AND SHOULD BE USED IN THIS RATE CASE PROCEEDING.

Test-year sales volumes are a key factor in calculating a utility's revenue requirement because sales levels directly impact both revenues and expenses, and hence the overall revenue requirement. Because the sales forecast is the foundation of a utility's test-year revenue calculations, without reasonable sales projections, a reliable estimate of test-year revenue cannot be determined.

MERC accepted use of the Department of Commerce, Division of Energy Resources' (the "Department") 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.[11] Going forward, MERC and the Department have agreed to work together to address future sales forecasting methodology.[12]

The Office of the Attorney General, Antitrust and Utilities Division ("OAG") asserts that MERC's sales forecast underestimates MERC's actual 2013 and 2014 sales volumes.[13] The OAG also argues that MERC's Transport sales forecast is not representative of the Company's historical Transport sales.[14] These concerns are without merit, however, since the OAG incorrectly included a non-jurisdictional component—the Michigan Taconite mines—in its test year sales forecast analysis.[15] The sales forecast agreed to by MERC and the Department

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11 Ex. 39 at 2 (H. John Rebuttal).

12 Evidentiary Hearing Transcript (May 13, 2014) at 106-108 (H. John); Evidentiary Hearing Transcript (May 13, 2014) at 207-209 (L. Otis).

13 V. Chavez Direct at 57 (This portion of Vincent Chavez's Direct Testimony was not adopted by OAG witness John Lindell and is therefore not part of the record.).

14 Ex. 151 at 14 (J. Lindell Direct).

15 Ex. 39 at 12 (H. John Rebuttal).

excludes these volumes, is reasonable, and should be used for purposes of setting rates in this proceeding.

IV. MERC'S PROPOSED RATE OF RETURN ON COMMON EQUITY WILL ALLOW MERC TO EARN A FAIR AND REASONABLE RETURN ON ITS PROPERTY.

A reasonable rate of return on common equity must be established to determine the revenue requirement for MERC. MERC has proposed, and the Department has found reasonable, a capital structure for the test year (January 1, 2014 – December 31, 2014), including the associated cost of long-term and short-term debt as follows:[16]

Component	Capitalization Ratio (%)	Cost (%)	Weighted Cost (%)
Long-term Debt	44.64%	5.5606%	2.4822%
Short-Term Debt	5.05%	2.3487%	0.1186%

As a result, the remaining variable in determining MERC's rate of return is to ascertain a reasonable rate of return on common equity. Once determined, the resulting rate of return is applied to the authorized rate base of the Company to determine MERC's required income.

The rate of return authorized for a public utility is directly related to the ability of the utility to meet its service responsibilities to its customers. A public utility is responsible for providing a particular type of service to its customers within a specific market area and is not free to enter and exit competitive markets in accordance with available business opportunities. A regulated utility must compete for capital in the market, and the level of rates must carefully consider the public's interest in reasonably-priced, safe, and reliable service. MERC witness Mr. Moul explained that:

> The Commission's rate of return allowance must be set to cover MERC's interest and dividend payments, provide a reasonable

[16] Ex. 28 at 3, LJG-1 (L. Gast Direct); Ex. 200 at 35-44 (E. Amit Direct); Ex. 201 at 27 (E. Amit Rebuttal); Ex. 202 at 12 (E. Amit Surrebuttal).

> level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which MERC's capital is exposed, assure confidence in the financial integrity of MERC, support reasonable credit quality, and allow MERC to raise capital on reasonable terms.[17]

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. Accordingly, various financial models must be used to estimate a reasonable return on common equity that should be authorized for MERC.[18]

The return on equity ("ROE") determination in a general rate case is always one of the most important decisions for the any public utility commission to make. The return on equity provides the most direct signal to the investment community regarding whether the utility will generate sufficient earnings to enable investors to earn a rate of return that is reasonable in light of their other investment opportunities. The authorized return on equity provides a widely understood benchmark that investors can use to compare different investment opportunities. Investors will commit their capital to those investment opportunities with the highest available return at a given level of risk.[19]

In its expert testimony, MERC 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.[20] MERC's analysis demonstrates that MERC's return on common equity should be set at 10.75 percent.[21] If the Commission does not agree with a

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[17] Ex. 17 at 3-4 (P. Moul Direct).

[18] Ex. 17 at 2-4 (P. Moul Direct).

[19] Ex. 18 at 6-8 (P. Moul Rebuttal).

[20] *See generally* Ex. 17 (P. Moul Direct); Ex. 18 (P. Moul Rebuttal).

[21] Ex. 17 at 1-2, 6, 9, 46 (P. Moul Direct); Ex. 18 at 4-5, 9, 40 (P. Moul Rebuttal).

10.75 percent ROE for MERC, based on the increase in capital costs since MERC's last rate case, the equity return in this case should be at least 10.27 percent.[22]

The Department has also prepared an analysis of MERC's return on common equity and is recommending that the Commission approve a return on common equity of 9.29 percent.[23] In addition, the OAG has prepared an analysis of MERC's return on common equity and is recommending that the Commission approve a return on common equity of 8.62 percent.[24] The record, however, demonstrates that there are additional risk considerations that must be taken into account in order to determine a reasonable return on common equity for MERC that the Department and the OAG did not include in their analyses, and that support MERC's recommended return on equity of 10.75 percent. The preponderance of evidence shows that these additional risk considerations must be considered in order for the return on common equity awarded in this case to meet the test set forth in *Bluefield* and *Hope*.

A. MERC Presented a Thorough Analysis of the Return on Common Equity that Appropriately Considered the Results of Three Recognized Financial Models.

Because MERC itself is not a publicly traded company, MERC determined its recommended ROE by considering the results of three well-recognized measures of the cost of equity applied to market and financial data developed from a proxy group of thirteen gas and electric companies.[25] The three financial models that MERC used to develop its cost of equity are the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, and the Capital Asset Pricing Model ("CAPM").[26] MERC also considered, as a check on the results of

[22] Ex. 18 at 40 (P. Moul Rebuttal).

[23] Ex. 202 at 2, 10-12 (E. Amit Surrebuttal).

[24] Ex. 165 at 2 (P. Chattopadhyay Surrebuttal).

[25] Ex. 17 at 3-5 (P. Moul Direct).

[26] Ex. 17 at 3 (P. Moul Direct).

these models, the Comparable Earnings ("CE") approach.[27] MERC's 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 a meaningful 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.[28]

The DCF model attempts to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. DCF return therefore consists of a current cash yield (the dividend yield) and future price appreciation (growth) of the investment. While it is widely used as an input to rate of return determinations in utility rate cases, Mr. Moul testified to the model's limitations.[29] First, the DCF analysis has a certain circularity when applied to the utility industry, because investors' expectations for the future depend on decisions of regulatory bodies. In turn, the regulatory bodies 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. The DCF model, therefore, may not fully reflect the true risk of a utility. [30] Additionally, the DCF model has limitations that make it less useful in the rate setting process where, as in the case of Mr. Moul's proxy group, the firm's market capitalization diverges significantly from the book value capitalization. Because this

[27] Ex. 17 at 3-5 (P. Moul Direct); Ex. 18 at 3 (P. Moul Rebuttal).

[28] Ex. 18 at 3-5 (P. Moul Rebuttal).

[29] Ex. 17 at 19-20 (P. Moul Direct).

[30] Ex. 17 at 19-20 (P. Moul Direct).

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.[31]

The RP model determines the cost of equity by adding a premium to corporate bond yields to account for the fact that common equity capital is exposed to greater investment risk than debt capital.[32] 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.[33] 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. Mr. Moul further 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.[34] The result of this methodology produced an updated ROE of 12.14 percent.[35]

The CAPM model uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As a result, the CAPM computes a cost of equity by determining a risk-free rate of return, a measure of systematic risk called the Beta, and a market risk premium that is determined by subtracting the risk-free rate of return from the total return on the market of equities.[36] Using the CAPM model, Mr. Moul computed a cost of common equity of 10.89 percent, after recognizing that the

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31 Ex. 17 at 44-45 (P. Moul Direct); *see also* Ex. 17 Schedule (PRM-1) (P. Moul Direct) for the specific calculations and computations performed by Mr. Moul.

32 Ex. 17 at 33-36 (P. Moul Direct).

33 Ex. 17 at 33-34 (P. Moul Direct).

34 Ex. 17 at 34-36 (P. Moul Direct).

35 Ex. 18 at 36 (P. Moul Rebuttal).

36 Ex. 17 at 37 (P. Moul Direct).

companies in Mr. Moul's proxy group are entitled to a size adjustment based on their market capitalization.[37]

As Mr. Moul's testimony demonstrates, all of the methods have strengths and weaknesses. 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.[38] The record evidence supports that Mr. Moul's recommendation of 10.75 percent, determined by using three financial models that account for different factors, is more reasonable than a ROE calculation that relies on only one imperfect method.

B. MERC Has Demonstrated that Its Proposed Return on Equity Appropriately Considered Risk Factors that are Unique to MERC and the Department's Failure to Consider Them is Unreasonable.

The ROE must reflect the risk factors that are unique to MERC to be consistent with investor requirements.[39] Mr. Moul demonstrated that MERC faces risks that are unique to MERC as compared to the gas and electric company proxy groups used in the models or an average gas utility. As such, the cost of capital awarded in this case must account for these risks or MERC may be unable to attract sufficient capital required to meet its responsibilities.[40] 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 that are well-documented in the record, Dr. Amit and Dr. Chattopadhyay have understated the cost of equity considerably.[41]

[37] Ex. 17 at 37 (P. Moul Direct).

[38] Ex. 17 at 5-7 (P. Moul Direct); Ex. 18 at 3 (P. Moul Rebuttal).

[39] Ex. 17 at 8-11, 17 (P. Moul Direct); Ex. 18 at 4-5, 14-15 (P. Moul Rebuttal).

[40] Ex. 17 at 8-17 (P. Moul Direct); Ex. 18 at 4-5, 12-15, 17-18, 21, 25, 35-36 (P. Moul Rebuttal).

[41] Ex. 18 at 4-5, 12-14, 17-18, 21, 25, 35-36 (P. Moul Rebuttal).

1. It is reasonable to make an adjustment to the CAPM to account for the small cap size of MERC when determining its cost of equity.

The record evidence demonstrates 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.[42] Specifically, a well-known and well-accepted study identified the size of a firm as a separate factor that must be recognized in addition to the Beta measure of systemic risk in explaining investor expected returns.[43] Mr. Moul also explained that, all other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm.[44]

Mr. Moul testified that MERC is several orders of magnitude smaller than the average size of his proxy group and of the S&P Public Utilities Index.[45] Mr. Moul's testimony established that additional compensation is required for the companies that are below the large-cap category. 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.[46] Mr. Moul, however, adopted a more conservative size adjustment of 1.12 percent in this case, which represents the mid-cap adjustment.[47] Mr. Moul applied this adjustment to the results of his CAPM model to account for the size of MERC and the known increased risks associated with a smaller utility. This size adjustment contributed to the significant difference between his CAPM results of 11.97 percent and Dr. Amit's and

42 Ex. 17 at 40-41 (P. Moul Direct); Ex. 18 at 35-36 (P. Moul Rebuttal).

43 Ex. 17 at 40-41 (P. Moul Direct) (discussing the results of the Fama and French study); Ex. 18 at 17-18, 36 (P. Moul Rebuttal).

44 Ex. 17 at 13-14 (P. Moul Direct).

45 Ex. 17 at 13-14, 17 (P. Moul Direct); Ex. 18 at 4-5 (P. Moul Rebuttal).

46 Ex. 17 at 36 and Exhibit (PRM-1), Schedule 12 (P. Moul Direct).

47 Ex. 17 at 40-41 (P. Moul Direct); Ex. 18 at 17-18 (P. Moul Rebuttal).

Dr. Chattopadhyay's considerably lower CAPM results of 9.79 percent and 10.09 percent, respectively.[48]

The points that Dr. Amit makes in defense of excluding the size adjustment are not properly applied in this case.[49] Dr. Amit's proxy group is not comprised of utilities that are sufficiently similar to MERC. There are observable risk differences between MERC and Dr. Amit's comparison group such that use of Dr. Amit's comparison group would provide a non-compensatory return for MERC. Dr. Amit explicitly recognized that MERC has more financial risk than the comparison group used in his cost of equity analysis.[50] Specifically, Dr. Amit provides a portfolio of companies that reflects a composite risk that is less than MERC's risk and does not compare the risk characteristics of his comparison group to MERC's specific risk characteristics.[51] Absent a valid comparison between MERC and Dr. Amit's comparison group, a generically derived cost of equity obtained from Dr. Amit's comparison group has little bearing on the return requirements for MERC given that the Company's risk is observably different.[52]

In addition, with the exception of one, 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 is approximately $205.9 million, which puts MERC in the small cap group. There are no small cap companies like MERC in Dr. Amit's comparison group. As established in the Direct Testimony of Mr. Moul and shown by the Morningstar 2014 Classic Yearbook, additional

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[48] Ex. 18 at 17-18 and Schedule (PRM-2) (P. Moul Rebuttal); Ex. 202 at 11 (E. Amit Surrebuttal); Ex. 165 at 2 (P. Chattopadhyay Surrebuttal).

[49] Ex. 200 at 7-13 (E. Amit Direct).

[50] Ex. 200 at 13 (E. Amit Direct).

[51] Ex. 18 at 14-15 (P. Moul Rebuttal).

[52] *See* Ex. 18 at 4-5, (P. Moul Rebuttal).

compensation is required for companies that are below the large cap category. Thus, a size adjustment is required to account for the small cap size of MERC in determining its cost of equity.[53]

Dr. Chattopadhyay also declined to adopt a size adjustment because he believes that the evidence on small-firm effect is not persuasive, and because he claims there is evidence that the size effect may not apply to regulated utility operations.[54] Dr. Chattopadhyay's claims are inappropriate in this case. Mr. Moul provided evidence of extensive academic research that shows there are specific risks associated with small size. 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 Betas for non-regulated companies were higher than the Betas of utilities. However, even setting aside the dated nature of the article, 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.[55] MERC also notes that Dr. Chattopadhyay removed companies from and failed to include companies in his proxy group that would have made the risk portfolio of his proxy group more accurately reflect MERC's risk profile.[56]

The idea that a size adjustment is not needed in this case is inaccurate. The central question is whether MERC will be able to attract investors when compared to similarly situated companies, which certainly include regulated utilities. Mr. Moul testified that all other things being equal, a smaller company is riskier than a larger company.[57] Unless MERC's cost of

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[53] Ex. 17 at Schedule (PRM-1) (P. Moul Direct); Ex. 18 at 6-8, 18 (P. Moul Rebuttal).

[54] Ex. 161 at 49-50 (P. Chattopadhyay Direct).

[55] Ex. 18 at 35-36 (P. Moul Rebuttal).

[56] Ex. 18 at 25-26 (P. Moul Rebuttal).

[57] *See* Ex. 17 at 7, 12-17 (P. Moul Direct); Ex. 18 at 17-18 (P. Moul Rebuttal).

equity compensates for that additional risk, MERC is placed at a disadvantage against its larger counterparts.

The record evidence supports that a size adjustment is necessary because MERC is smaller than the companies in the proxy groups and the average utility. Mr. Moul proposes a size adjustment that is reasonable and conservative. Neither Dr. Amit, nor Dr. Chattopadhyay, used a proxy group that accounts for MERC's size or provides an appropriate size adjustment in their findings. MERC' proposed ROE, which incorporates an appropriate size adjustment, therefore, best allows MERC to attract sufficient capital required to meet its responsibilities.

2. It is reasonable to consider MERC's reliance on large volume customers when determining the cost of equity.

MERC's risk profile is greatly influenced by the natural gas that it sells or delivers to large volume customers. The record demonstrates that this customer class represents approximately 79 percent of MERC's total throughput.[58] This customer class presents a much greater risk to a natural gas company than a residential customer. Mr. Moul testified that the large volume users have the ability to bypass the Local Distribution Company ("LDC") (such as MERC). While MERC has been successful in its efforts to avoid bypass to date, MERC is at the mercy of the business cycle, the price of alternative energy sources, and pressures from competitors. Further, external factors can also 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.[59] Mr. Moul's cost of equity accounts for this risk.[60] Dr. Amit's does not.

[58] Ex. 17 at 2-3, 8-9 (P. Moul Direct).

[59] Ex. 17 at 2-3, 8-9 (P. Moul Direct).

[60] Ex. 17 at 2-3, 8-9 (P. Moul Direct).

3. It is reasonable to consider MERC's higher earning variability, its higher operating ratio, and its lower interest coverage when determining the cost of equity.

Mr. Moul testified that MERC has experienced much higher variability in its returns in a five-year period as compared to the S&P Public Utilities and his proxy group of natural gas companies. Mr. Moul also testified that MERC has a higher five-year average operating ratio (the percentage of revenues consumed by operating expenses, depreciation and taxes other than income) than the S&P Public Utilities and his proxy group. Mr. Moul also testified that MERC had a lower interest coverage (the multiple by which available earnings cover fixed charges, such as interest expense) than the S&P Public Utilities and his proxy group.[61] All three of 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. The record evidence supports a cost of equity that accounts for this risk. Mr. Moul's proposed cost of equity accounts for this risk while Dr. Amit's and Dr. Chattopadhyay's do not.

C. MERC Demonstrated that its Proposed Return on Equity Appropriately Considered Additional Risk Factors and the Department's Failure to Consider Them is Unreasonable.

In addition to risk factors that are unique to MERC, the record also demonstrates that there are additional risks that investors will consider that are 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 continue to perceive additional risks in making equity investments. As a result, Mr. Moul testified that a conservative cost of equity continues to

[61] Ex. 18 at 14-16, 21 (P. Moul Rebuttal).

be necessary for MERC in order 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.

1. It is reasonable to include a leverage adjustment to the DCF and CAPM analyses.

Mr. Moul computed a leverage adjustment for both 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.[62] Therefore, if the DCF results are used to compute the weighted average cost of capital based on a book value capital structure used for rate setting purposes, the utility will not, by definition, recover its risk-adjusted capital cost.[63] The leverage adjustment reflects the gap that must be bridged when using a market price in the DCF that relates to market value weights that differ from book value weights used in public utility rate setting.[64]

Dr. Amit rejected this argument essentially by arguing that it assumes that investors are "being duped" and willingly pay too much for a stock when the return will be established on a book value capital structure rather than the market value of the utility's assets.[65] Mr. Moul testified that is not what the adjustment assumes; instead, it recognizes that a market determined cost of equity is developed in standard rate setting practice and it reflects a level of financial risk that is different from the capital structure stated at book value.[66]

Dr. Chattopadhyay rejected Mr. Moul's leverage adjustment arguing that the leverage adjustment would further encourage stock price to deviate away from book value at the expense

[62] Ex. 18 at 13-14 (P. Moul Rebuttal).

[63] Ex. 18 at 13-14 (P. Moul Rebuttal).

[64] Ex. 18 at 12-15, 17 (P. Moul Rebuttal).

[65] Ex. 200 at 65-69 (E. Amit Direct); Ex. 202 at 21 (E. Amit Surrebuttal).

[66] Ex. 18 at 12-15 (P. Moul Rebuttal).

of retail customers and to the benefit of investors.[67] Mr. Moul testified that his leverage adjustment does not depend on establishing or targeting any particular ratio of price to book value and does not address any of the factors that would cause market prices to deviate from book value.[68] Rather, Mr. Moul's adjustment reflects the risk related to financial leverage and adds stability to the DCF return because the adjustment will increase or decrease as the dividend yield changes. Mr. Moul's adjustment solely addresses variations in financial risk, and is based on book values that are typically used in the rate setting process. There is no market-to-book adjustment included in Mr. Moul's leverage adjustment.[69]

Mr. Moul's adjustment deals with the risk difference between the common equity ratio using market capitalization (the sole consideration of investors) and the book value to common equity ratio used in utility ratemaking.[70] 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.

D. Because the Department's and the OAG's Proposed Costs of Equity are Understated They Do Not Meet the *Bluefield* and *Hope* Factors.

Mr. Moul testified 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, all else being equal. Because investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least

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67 Ex. 161 at 5, 19-21 (P. Chattopadhyay Direct); Ex. 165 at 37 (P. Chattopadhyay Surrebuttal).

68 Ex. 18 at 32 (P. Moul Rebuttal).

69 Ex. 18 at 32-34 (P. Moul Rebuttal).

70 *See* Ex. 18 at 12-14 (P. Moul Rebuttal).

equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.[71]

Despite MERC's unique risk factors, and the additional risk factors established in the record, Dr. Amit and Dr. Chattopadhyay are recommending costs of equity that are well below what investors would require from MERC. Dr. Amit testified that based on his DCF method and two growth rate DCF analyses, MERC should receive a ROE of 9.29 percent.[72] The cost of equity Dr. Amit is recommending in this case is 11 basis points lower than the recommended ROE of 9.40 percent in his Direct Testimony and 146 basis points lower than MERC's recommended ROE of 10.75 percent.[73]

Dr. Amit's recommended ROE is also low as compared to the rates of return allowed by other state utility commissions in 2013. 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.[74] Both of the averages exceed Dr. Amit's recommended ROE by at least 50 basis points.

Dr. Amit's recommended cost of equity is lower than Value Line's average rate of return of 11.49 percent for its natural gas utility companies over the 2017 through 2019 period. In addition, 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.[75] Finally, Dr. Amit's ROE is lower

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[71] *See* Ex. 17 at 11, 13-17 (P. Moul Direct); Ex. 18 at 21 (P. Moul Rebuttal).

[72] Ex. 200 at 2-7, 25-26, 28-33 (E. Amit Direct); Ex. 202 at 2 (E. Amit Surrebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 198-205 (E. Amit).

[73] Ex. 202 at 2 (E. Amit Surrebuttal).

[74] Ex. 18 at 6 (P. Moul Rebuttal).

[75] Ex. 18 at 8-9 (P. Moul Rebuttal).

than the cost of equity that the Commission has awarded other natural gas LDCs since MERC's last rate case, when the Commission set MERC's cost of equity at 9.70 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.[76] 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 the capital markets, the Commission should not provide MERC with an equity return lower than 10 percent. Anything lower may jeopardize MERC's ability to attract capital, and in turn, appropriately meet its service responsibilities to customers.[77]

One of the tests established in *Bluefield* and *Hope* to determine if a utility's rate of return is fair and reasonable is that the rate of return should be similar to that of other financially sound businesses having similar or comparable risks.[78] The record evidence shows 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. This is in spite of the fact that the record demonstrates that MERC faces additional unique risks as compared to other natural gas utilities and, therefore, cannot be said to have "similar or comparable risks" to the average natural gas LDC. That Dr. Amit is proposing a

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[76] S*ee In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 32 (June 9, 2014) ("CPE Findings of Fact, Conclusions, and Order"); *In the Matter of Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 11-12 (Sept. 3, 2013). *See also In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-001/GR-10-276, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 10 (Aug. 12, 2011) (setting the ROE in the electric rate case at 10.35); and *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-10-239, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 43-44 (Apr. 25, 2011) (setting the ROE in the electric rate case at 10.74).

[77] Ex. 18 at 8 (P. Moul Rebuttal).

[78] Ex. 17 at 3-4, 42-43 (P. Moul Direct), citing *Bluefield Water Works & Investment Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) and *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

significantly lower than average ROE without making any adjustment or compensation for MERC's unique risk factors prohibits MERC from having a rate of return similar to a Minnesota natural gas LDC with comparable risk.

Dr. Chattopadhyay's testified that based on his DCF analysis, MERC should receive a ROE of 8.62. His range of reasonable allowed returns on equity is 8.60 to 9.10 percent. [79] Dr. Chattopadhyay's recommended cost of equity is 213 basis points below MERC's recommended ROE. Even the upper end of the ROE range that Dr. Chattopadhyay finds reasonable is 165 basis points below MERC's recommended ROE. Dr. Chattopadhyay's ROE is so low that it is not credible in this case.

Dr. Chattopadhyay proposes to significantly reduce MERC's ROE when capital costs have increased since the Company's last rate case. In addition, the increase in yield on Treasury bonds demonstrates that Dr. Chattopadhyay's proposal in this case will not result in a reasonable return for MERC.[80] Dr. Chattopadhyay seems inclined toward a low return because he bases his ROE recommendation, at least 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. This information, combined with the fact that MERC has experienced historically high earnings variability and its operating ratio is well above average, show that MERC requires an above average return on equity to compensate for its above average risk.[81]

Dr. Chattopadhyay also bases 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

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[79] Ex. 165 at 2 (P. Chattopadhyay Surrebuttal).

[80] Ex. 18 at 20 (P. Moul Rebuttal).

[81] Ex. 18 at 21 (P. Moul Rebuttal); Ex. 161 at 28-29 (P. Chattopadhyay Direct).

cost of equity.[82] Both MERC and the Department disagree with Dr. Chattopadhyay's conclusion that the DCF analysis results in an upwardly biased estimate of the cost of common equity when the market-to-book ratio is greater than one.[83] 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.[84]

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. The market-to-book ratio for Dr. Amit's comparison group 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 not only counter to basic financial principals, it is counter to common sense. Such excessive returns should have produced a run on gas utility stocks until the excessive profits were eliminated. Because market-to-book ratios continue to be significantly above one, it is clear this did not happen. In addition, the financial literature cited by Dr. Chattopadhyay does not support his upwardly biased ROE claim and Dr. Chattopadhyay's

82 Ex. 161 at 13-17 (P. Chattopadhyay Direct); Ex. 164 at 25-28 (P. Chattopadhyay Rebuttal).

83 Ex. 18 at 21-22 (P. Moul Rebuttal); Ex. 201 at 3-4 (E. Amit Rebuttal).

84 Ex. 18 at 21-24 (P. Moul Rebuttal).

own empirical studies produce unreasonably low ROEs when the market-to-book ratio equals one.[85]

The record evidence demonstrates that Dr. Amit's recommended ROE of 9.29 percent is 220 basis points lower than the widely-referenced Value Line industry forecasts for 2017-2019 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.[86] 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 severely harm MERC's chances of meeting investor expectations. As such, 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. The preponderance of the evidence supports Mr. Moul's cost of equity as the fair and reasonable cost of equity in this case.

E. MERC Has Demonstrated that the Flotation Cost Adjustment Made by MERC is Necessary for MERC to Earn its Reasonable Rate of Return.

The record demonstrates that a flotation cost adjustment is a common adjustment recognized by the Commission that is necessary in order to allow a utility to earn its reasonable rate of return. 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.[87] Dr. Amit testified that when companies issue equity, the price paid by investors for the new shares is higher than the revenues per share received by the

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85 Ex. 201 at 7-9 (E. Amit Rebuttal).

86 Ex. 17 at 7 (P. Moul Direct).

87 Ex. 18 at 31, 38-39 (P. Moul Rebuttal); Ex. 200 at 26-27 (E. Amit Direct); Ex. 201 at 25 (E. Amit Rebuttal); Ex. 202 at 5, 35-36 (E. Amit Surrebuttal).

company. The difference is issuance or flotation costs, the fees and expenses the company must pay as part of the issue.[88] Mr. Moul testified that the market models of cost of equity use the quoted stock prices as model components. Before a utility can invest the net proceeds from a common stock issuance in its rate base upon which it can earn a rate of return, it must incur expenses from the underwriter's discount/commission.[89] The utility, therefore, inevitably experiences an additional expense that is not accounted for in the cost of equity models.

The Commission frequently approves cost of equity recommendations adjusted for flotation costs in rate cases.[90] There is nothing unusual about including a flotation cost in the

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[88] Ex. 200 at 26-27 (E. Amit Direct); Ex. 201 at 25 (E. Amit Rebuttal); Ex. 202 at 5, 35-36 (E. Amit Surrebuttal).

[89] Ex. 18 at 38 (P. Moul Rebuttal).

[90] Ex. 23 at 23 (P. Moul Rebuttal). *See e.g., In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 31-32 (June 9, 2014) (concurring with the ALJ recommendations regarding ROE, which included a flotation cost adjustment of 16 basis points in paragraph 286 of the April 9, 2014 ALJ order); *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 11-12 (Sept. 3, 2013) (concurring with the ALJ findings regarding ROE, which included a flotation cost adjustment of 13 basis points in paragraph 365 of the July 3, 2013 order); *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 10-11 (May 14, 2012) (adopting the settlement regarding a flotation cost adjustment of 15 basis points as described in paragraphs 87 and 88 of the February 22, 2012 ALJ order); *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-001/GR-10-276, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 8-12 (Aug. 12, 2011) (including a flotation cost adjustment of 18 basis points); *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-10-239, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 42-43 (Apr. 25, 2011) (concurring with the ALJ findings regarding ROE, which included 20 basis points in paragraph 388 of the February 14, 2011 Order); *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G002/GR-09-1153, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 27 (Dec. 6, 2010) (including a flotation cost adjustment of 23 basis points); *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rate in Minnesota*, Docket No. G008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (Jan. 11, 2010) (including a flotation cost adjustment of 20 basis points).

cost of equity in a rate case.[91] Based on his calculations, Mr. Moul proposes a flotation cost adjustment of 14 basis points; Dr. Amit proposes a flotation cost adjustment of 15 basis points.[92]

Despite the widely accepted practice of recognizing this known expense in determining the cost of equity in a rate case, OAG witness Mr. Chattopadhyay testified that it should not be recognized in this case. Mr. Chattopadhyay argues that where the market-to-book ratio is greater than one, the DCF produces a ROE that is biased upward and, therefore, already accounts for flotation cost adjustment.[93]

Dr. Chattopadhyay's argument is without merit because his failure to modify his DCF results for flotation costs results in an understatement of the required rate of return on common equity. Moreover, Dr. Chattopadhyay included external financing growth in his DCF analysis, which mandates a flotation cost adjustment. Dr. Chattopadhyay incorrectly argues that with his proposed rate of return on common equity there is an adequate cushion to cover flotation costs. As previously discussed, flotation cost allowance is designed to account for the fact that the underwriter's discount/commission and the utility's out-of-pocket expense must be paid before the utility can invest the net proceeds from a common stock issuance into the rate base on which it earns a return. 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.[94]

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[91] Ex. 18 at 31, 38-39 (P. Moul Rebuttal) (citing a .23 percent flotation cost adjustment in the *Northern States Power* rate case, Docket No. G002/GR-09-1153, a .20 percent flotation cost adjustment in the *Center Point Energy* rate case, Docket No. G008/GR-08-1075, and a 0.17 flotation cost adjustment in MERC's last rate case, Docket No. G007,011/GR-10-977).

[92] Ex. 18 at 10, 38 and Schedule (PRM-2) (P. Moul Rebuttal); Ex. 201 at 26 (E. Amit Rebuttal). The Department found MERC's proposed average flotation cost for public utilities to be a reasonable flotation factor, but incorporates the flotation adjustment at a different stage in the DCF analysis. Ex. 18 at 38 (P. Moul Rebuttal); Ex. 200 at 26-27, 50 (E. Amit Direct); Ex. 202 at 14, 34-36 (E. Amit Surrebuttal).

[93] Ex. 161 at 43-45 (P. Chattopadhyay Direct); Ex. 164 at 25-27 (P. Chattopadhyay Rebuttal); Ex. 165 at 33-36, 38 (P. Chattopadhyay Surrebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 182 (P. Chattopadhyay).

[94] Ex. 18 at 31, 38-39 and Schedule (PRM-2) (P. Moul Rebuttal).

Because the DCF analysis does not produce an upward biased ROE estimate, the DCF results must be adjusted for flotation costs. Dr. Chattopadhyay's recommendation to exclude a flotation cost adjustment in this case is unreasonable, not supported by record evidence and, if accepted, would deny MERC the reasonable opportunity to earn a fair rate of return. Dr. Amit testified that without a flotation cost adjustment a utility is not able to realize the investor required return. This is because there is an inescapable cost to issuing the common stock of the proxy groups upon which the cost of equity is based in this case.[95] Denial of a flotation cost would make a public utility less competitive to attract capital because investors buying new shares of stock will only buy them if they expect to earn their required rate of return. Absent a flotation cost adjustment, there is no incentive to purchase the stock because existing shareholders will not be able to receive their required rate of return.[96] Dr. Amit explained that the adjustment is appropriate even if no new issuances are planned for the test year, and that the effect of the flotation costs carries forward into subsequent years.[97] In conclusion, MERC has demonstrated that the flotation cost adjustment made by MERC is necessary for MERC to earn its reasonable rate of return, and MERC respectfully requests that the Commission accept its flotation cost adjustment as proposed.

V. THE DEPARTMENT'S PROPOSED ADJUSTMENT TO GAS REVENUE TO ACCOUNT FOR CONSERVATION IMPROVEMENT PROGRAM EXPENSES IS UNJUSTIFIED AND WOULD NOT BE REVENUE NEUTRAL.

MERC initially included $8,920,481 of Conservation Improvement Program ("CIP") expense in test-year expense, which reflected 2013 rather than 2014 expense.[98] MERC acknowledged the error in response to information requests and recognized that the correct

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95 Ex. 200 at 26-27 (E. Amit Direct); Ex. 201 at 24-25 (E. Amit Rebuttal); Ex. 202 at 35-36 (E. Amit Surrebuttal).

96 Ex. 201 at 25 (E. Amit Rebuttal).

97 Ex. 200 at 26-27 (E. Amit Direct).

98 Ex. 19 at 42-43 (S. DeMerritt Direct).

amount of test-year CIP expense should have been $9,369,422, as reflected in the CIP budget approved by the Deputy Commissioner of the Minnesota Department of Commerce in Docket No. G007,011-CIP-12-548.[99] In Rebuttal Testimony, MERC agreed to increase CIP expense to reflect 2014 expense, as proposed by Department witness Ms. St. Pierre, and provided a recalculated Conservation Cost Recovery Calculation ("CCRC") based on the corrected CIP expense and the Department's alternative sales forecast. The Department recommended that MERC also increase natural gas revenue by $3,758,090 to offset for the increase in CIP expense.[100]

This proposed increase would incorrectly lower MERC's revenue deficiency while the expenses related to CIP actually increase. In other words, the Department is recommending an overall rate increase of approximately $3.3M, while CIP expense alone is increasing approximately $3.8M. Therefore, if approved, this adjustment would have the effect of reducing MERC's rates by $0.5M for all of MERC's other costs included in this case. By imputing CIP revenues of approximately $3.8M to offset the increase in CIP expense, the Department is effectively reducing MERC's revenue requirement based on revenue that will never be collected.[101] The impact of MERC's proposed approach as compared to the approach advocated by the Department is illustrated as follows:

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[99] Ex. 21 at SSD-3 (S. DeMerritt Supplemental Direct Exhibits); Ex. 218 at MAS-15 (M. St. Pierre Direct Attachments).

[100] Ex. 217 at 15 (M. St. Pierre Direct).

[101] Ex. 24 at 5 (S. DeMerritt Rebuttal).

DOC Position (in millions)						
	Exclusive of CCRC Increase		CCRC Increase			
Total Expenses	$	296.4	$	3.8	$	300.1
WACC x Rate Base		14.0			$	14.0
Revenue Requirement		310.3		3.8		314.1
Revenues		312.2			$	312.2
Income Deficiency	$	(1.8)	$	3.8	$	1.9
Gross Revenue Conversion Factor		1.704		1.704		1.704
Revenue Deficiency	$	(3.1)	$	6.4	$	3.3

MERC Position (in millions)						
	Exclusive of CCRC Increase		CCRC Increase			
Total Expenses	$	286.3	$	3.8	$	290.0
WACC x Rate Base		16.0			$	16.0
Revenue Requirement		302.2		3.8		306.0
Revenues		298.8	$	-	$	298.8
Income Deficiency	$	3.4	$	3.8	$	7.1
Gross Revenue Conversion Factor		1.704		1.704		1.704
Revenue Deficiency	$	5.8	$	6.4	$	12.2

As seen in the above table, under the approach advocated by the Department, by adding approximately $3.8M of revenues, MERC actually receives a rate decrease for all items not CIP related. This is based on the fact that MERC will have to record higher CIP expense on the income statement due to the increased CCRC, but will not collect the higher revenue because the revenue deficiency is artificially low and, therefore, MERC will not be able to adjust its base rates, which the CCRC revenue side is a component of.

The Department's argues that CIP expense should be made "revenue neutral" by treating it similarly to gas costs, where the revenue from the sale of gas is equal to revenue.[102] Specifically, Ms. St. Pierre recommended that MERC be required to increase the test-year CIP

[102] Ex. 217 at 14-15 (M. St. Pierre Direct); Ex. 219 at 11-12 (M. St. Pierre Surrebuttal).

revenue to the level of CIP expense.[103] This proposed adjustment would result in MERC having to incorrectly lower its revenue deficiency, resulting in an effective rate reduction, without any justification for such a reduction.

During the evidentiary hearing, Ms. St. Pierre conceded that the Department's proposal would reduce MERC's revenue deficiency.[104] Ms. St. Pierre also acknowledged that, as a general rule, if the overall revenue deficiency is reduced, MERC is then precluded from increasing its base rates by the same amount.[105] The Department incorrectly argues, however, that CIP expense should be given different treatment than other expenses for ratemaking purposes.[106] According to Ms. St. Pierre, this recommendation "is to account for the Conservation Cost Recovery Charge (CCRC), 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."[107] However, MERC's CCRC, unlike its base cost of gas, is embedded within MERC's base distribution rate.[108] This difference is significant in how the Department's recommended treatment affects MERC's rate recovery. On the one hand, if the Commission approves a higher base cost of gas, which is a separate bill charge *not* embedded in MERC's base distribution rates, MERC would recover more revenue associated with that adjustment, regardless of approved rates. In contrast, even if the Commission approves a higher CCRC at the conclusion of MERC's rate case, because this adjustment is embedded in MERC's base distribution rates, MERC would still be limited in its overall rate recovery to the final rates approved by the Commission, even though a larger portion

[103] Ex. 217 at 15 (M. St. Pierre Direct); Ex. 219 at 12 (M. St. Pierre Surrebuttal).

[104] Evidentiary Hearing Transcript (May 13, 2014) at 221 (M. St. Pierre).

[105] Evidentiary Hearing Transcript (May 13, 2014) at 222 (M. St. Pierre).

[106] Evidentiary Hearing Transcript (May 13, 2014) at 222 (M. St. Pierre).

[107] Ex. 219 at 12-13 (M. St. Pierre Surrebuttal).

[108] *See* Evidentiary Hearing Transcript (May 13, 2014) at 221 (M. St. Pierre).

of those rates would be booked to MERC's CIP tracker. Therefore, the proposed adjustment to revenue would not result in CIP expense being "revenue neutral" but instead would reduce MERC's revenue requirement based on revenue that will never be collected. The evidence in the record demonstrates that this adjustment would be unreasonable, arbitrary, and without justification. MERC respectfully requests that the Commission accept its proposed CIP expense and reject the Department's proposal.

VI. MERC HAS DEMONSTRATED BY A PREPONDERANCE OF THE EVIDENCE THAT ITS PROPOSED TEST YEAR PROPERTY TAX EXPENSE REPRESENTS ACTUAL TAX EXPENSE.

MERC has proposed to include property tax expense of $7,195,869 for the 2014 test year, as summarized in the testimony of MERC witness John Wilde.[109] Contingent on MERC's agreement to provide additional updates regarding the status of pending property tax appeals, Department witness Ms. St. Pierre indicated that the Department is in agreement with MERC's recommended level of property tax expense.[110] MERC originally proposed to include $7,314,129 for property tax expense in the 2014 test year, but agreed with Department witness Ms. St. Pierre's recommendation that MERC reduce its property tax expense by $48,864 based on updated information.[111] Additionally, MERC proposed to decrease test year property tax expense by $70,000 for Kansas property tax expense based on revised tax assessment estimates received from the Kansas Attorney General.[112]

The OAG rejected MERC's proposed property tax expense, improperly arguing that MERC's proposal attempts to over-inflate costs by using a future test year based on base year

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109 Ex. 37 at 5-6 (J. Wilde Rebuttal).

110 Ex. 219 at 24 (M. St. Pierre Surrebuttal).

111 Ex. 37 at 4 (J. Wilde Rebuttal).

112 Ex. 37 at 4 (J. Wilde Rebuttal).

2012 actual costs. Based on this flawed reasoning, the OAG has proposed an additional reduction of $690,700 to MERC's 2014 test year property tax expense.[113]

The OAG reached its property tax recommendation based on an estimate of Minnesota property taxes paid in 2013. The OAG's adjustment is inaccurate because it fails to account for any change in MERC's property tax expense for the 2013 accrual payable in 2014, or any change in the expense for the 2014 accrual payable in 2015.[114] The flawed nature of the OAG's calculation is demonstrated by the fact that MERC's actual tax liability for 2012, which was paid in 2013, was greater than the OAG's estimate for MERC's 2014 property tax expense.[115] OAG witness Mr. John Lindell attempts to support his inaccurate property tax calculation using 2013 property tax statements from a single county, Washington County, and a single property, MERC's property located in Scandia, Minnesota.[116] MERC's service area spans the state of Minnesota and covers 51 counties and 165 communities. Simply put, Mr. Lindell's analysis does not even attempt to reflect what is transpiring on a statewide basis or what MERC should expect to accrue for 2014 property taxes based on the Company's property assessments over the last several years. Thus, the OAG's recommended property tax expense does not accurately reflect MERC's actual test year property tax expense.

MERC has provided ample support in the record, based on actual data, for the Company's expectation that its 2014 property tax expense will increase on a statewide basis, and has provided a reasonable method to calculate property tax obligations for 2014 using actual

[113] Ex. 151 at 12-13 (J. Lindell Direct).

[114] Ex. 37 at 7 (J. Wilde Rebuttal).

[115] Ex. 37 at 7-8 (J. Wilde Rebuttal).

[116] Ex. 151 at 12-13 (J. Lindell Direct).

valuation methods and assumptions used by the State of Minnesota. Therefore, the ALJ and the Commission should find that MERC's proposed test year property tax expense is appropriate.

VII. MERC'S PROPOSED NET OPERATING LOSS CARRYFORWARD DEFERRED TAX ASSET IS PROPERLY INCLUDED IN RATE BASE.

MERC has proposed to include a deferred tax asset ("DTA") for a Net Operating Loss ("NOL") carryforward in its 2014 test year rate base.[117] The DTA represents MERC's stand-alone operating income NOL that arose in 2012 and 2013, due primarily to bonus depreciation.[118] Inclusion of the DTA NOL is necessary to accurately reflect MERC's cost of service and average rate base estimate for the test year. Additionally, inclusion of the DTA NOL is consistent with a normalized method of accounting such that exclusion of the NOL would not allow MERC to remain in compliance with the tax normalization rules.[119]

The OAG opposes inclusion of the DTA NOL in MERC's test year rate base.[120] OAG witness Mr. Lindell incorrectly claims that MERC is not entitled to claim the DTA NOL because MERC is not a taxpayer that can generate a NOL.[121] Mr. Lindell also claims that MERC has not demonstrated that the tax normalization rules would apply to the DTA NOL.[122] Finally, Mr. Lindell takes the position that because NOL will be used in 2014, there is no basis to include the deferred tax asset in rate base during 2014.[123]

In Rebuttal Testimony, MERC witness John Wilde explained why the adjustment the OAG proposes would not appropriately reflect MERC's cost of service and average rate base

117 Ex. 36 at 4-5 (J. Wilde Direct).

118 Ex. 36 at 4-5 (J. Wilde Direct).

119 Ex. 36 at 5-7 (J. Wilde Direct); Ex. 37 at 11-13, 15-20 (J. Wilde Rebuttal).

120 Ex. 151 at 8 (J. Lindell Direct).

121 Ex. 151 at 8 (J. Lindell Direct).

122 Ex. 151 at 9 (J. Lindell Direct).

123 Ex. 151 at 11 (J. Lindell Direct).

estimated for the test year and would not be consistent with a normalized method of accounting.[124] As a regulated public utility, MERC is subject to tax normalization rules. MERC must remain in compliance with the tax normalization rules or risk losing the benefits of accelerated federal tax depreciation.[125] As a regulated public utility, MERC generated a federal net operating loss during 2012 and 2013. MERC will not be able to receive the full benefits of claiming accelerated tax depreciation for 2012 and 2013 until the Company or the Integrys Consolidated group generates sufficient federal taxable income in 2014.[126] The regulatory practice of including deferred taxes as an adjustment to rate base reflects the fact that MERC is in possession of an interest-free source of funds from the federal government.[127] Reducing rate base for the DTA that results from claiming accelerated tax depreciation without reflecting the offsetting DTA for the NOL carryfoward, as the OAG recommends, would overstate the amount of interest-free funding that MERC possesses.[128]

Contrary to the position taken by the OAG, the fact that 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 carryfoward does not support exclusion of the DTA when it does occur. In Xcel Energy's 2010 electric rate case, Xcel and the Department entered into a "NOL Agreement" regarding the treatment of Xcel's NOL. That agreement was accepted by the Commission and

[124] Ex. 37 at 11-12 (J. Wilde Rebuttal).

[125] Ex. 37 at 11 (J. Wilde Rebuttal).

[126] Ex. 37 at 11 (J. Wilde Rebuttal).

[127] Ex. 37 at 11 (J. Wilde Rebuttal).

[128] Ex. 37 at 11-12 (J. Wilde Rebuttal).

included in the Commission's May 14, 2012 Findings of Fact, Conclusions, and Order.[129] Thus, the Commission has previously approved inclusion of a DTA NOL in rate base for a regulated public utility and should recognize the legitimacy of MERC's DTA NOL in this rate case.

VIII. MERC HAS DEMONSTRATED BY A PREPONDERANCE OF EVIDENCE THAT ITS NON-FUEL OPERATIONS AND MAINTENANCE COSTS ARE REASONABLE.

To calculate its 2014 non-fuel operations and maintenance ("O&M") expense, MERC used actual 2012 non-fuel O&M costs and applied an inflation factor for 2013 and 2014 and then applied known and measurable ("K&M") adjustments.[130] The inflation adjustment was based on an average of inflation from Value Line, Global Insight, Moore Inflation Predictor, Energy Information Administration, and International Monetary Fund.[131] MERC used 2.6% as a labor inflator rate based on union contract wage increases. MERC inflated non-labor expense 1.708% in 2013 and 1.993% in 2014, and labor expense 2.6% in 2013 and 2014.[132]

The K&M adjustments are adjustments to account for those items for which costs increased or decreased at a rate greater than the inflation rate applied.[133] Specifically, MERC applied 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,

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[129] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 35 (May 14, 2012); *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-10-971, Update to Summary of Issues at 5, 11 (Dec. 12, 2011) (citing Exhibit No. 105, Tax Normalization and Allowance for Net Operating Losses).

[130] Ex. 19 at 9 (S. DeMerritt Direct).

[131] Ex. 19 at 13 (S. DeMerritt Direct).

[132] Ex. 19 at 12 and Schedule (SSD-19) (S. DeMerritt Direct).

[133] Ex. 19 at 13-14 (S. DeMerritt Direct).

(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.[134] MERC also adjusted 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 ("LTIP"), Restricted Stock, and Stock Options, (5) 50% of economic development costs, (6) incentives, (7) the Vertex audit, and (8) benefits.[135] The methodology and specific K&M adjustments were summarized in the testimony and exhibits of MERC witness Seth DeMerritt.[136] MERC's proposed inflation adjustment for base O&M expense and proposed K&M adjustments provide the most reasonable estimate of MERC's test year O&M expense and should be approved by the ALJ and the Commission.

The OAG has taken the position that MERC's proposed inflation adjustment for the calculation of base O&M expense results in an unreasonable increase in costs for the test year because MERC uses two years of inflation and two years of adjustments.[137] In response to this concern, the OAG makes the unreasonable recommendation that MERC be required to calculate O&M expense using a single year inflation factor.[138] Specifically, Mr. Lindell recommends O&M expenses be inflated by 2.2% to determine test year O&M expense based on the three year average of annual inflation.[139] The OAG provides no support for this approach except its sense that the proposed O&M expense is too high.

[134] Ex. 19 at 13-14 (S. DeMerritt Direct).

[135] Ex. 19 at 13-15 (S. DeMerritt Direct).

[136] Ex. 19 at 12-25 and Exhibits SSD-2-SSD-19 (S. DeMerritt Direct and Schedules).

[137] Ex. 151 at 15–16 (J. Lindell Direct).

[138] Ex. 151 at 15-19 (J. Lindell Direct).

[139] Ex. 151 at 18-19 (J. Lindell Direct).

The OAG's recommendation is unreasonable and not consistent with MERC's overall rate case. Mr. Lindell seems to question why MERC chose 2014 as the test year and simply suggests that, for purposes of calculating O&M, the Commission should choose 2013 as the test year; thereby including only one year of inflation adjustment.[140] MERC filed this rate case based on a 2014 test year and using a 2012 historical year.[141] 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 rate case filing based on a 2014 test year and based on a 2012 historical test year because 2012 was the most recent historical test year available.[142] It is unreasonable for the OAG to propose an alternative test year for the purpose of calculating O&M expense in this case. MERC filed this case based on a 2014 test year and MERC's proposed methodology for calculating test year O&M expense is reasonable and consistent with MERC's prior rate cases. 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.[143]

Mr. Lindell also incorrectly characterizes MERC's approach to known and measureable changes as "unusual."[144] To the contrary, MERC's approach to K&M adjustments is the same approach MERC used in its last two rate cases (Docket Nos. G007,011/GR-08-835 and G007,011/GR-10-977). Additionally, contrary to the OAG's position, K&M changes must occur

[140] Ex. 24 at 21 (S. DeMerritt Rebuttal); Ex. 151 at 15-19 (J. Lindell Direct).

[141] Ex. 24 at 23 (S. DeMerritt Rebuttal).

[142] Ex. 24 at 21-22 (S. DeMerritt Rebuttal).

[143] *See* Ex. 25 at 23-25 (DeMerritt Rebuttal).

[144] Ex. 151 at 16 (J. Lindell Direct).

after the historic test year, otherwise there would be no need for the adjustment.[145] No party has raised any objection to the majority of MERC's proposed K&M adjustments, and those proposed adjustments should be adopted by the ALJ and Commission as reasonable based on the information and support provided in MERC's pre-filed testimony and during the evidentiary hearing. As outlined below, the Department and the OAG proposed adjustments or recommended that some of the proposed K&M adjustments be removed from O&M expense. For the reasons outlined below, MERC's proposed K&M adjustments are reasonable and should be adopted by the ALJ and the Commission.

A. MERC's Proposed Calculation of Uncollectable Expense is Consistent with Prior Decisions and Results in a More Predictable Level of Expense.

MERC has proposed to calculate uncollectible expense based on a three-year uncollectible expense ratio, consistent with the approach approved by the Commission in MERC's 2008 rate case, Docket No. G007,011/GR-08-835, and MERC's 2010 rate case, Docket No. G007,011/GR-10-977. The Department went to great lengths in MERC's 2010 rate case to justify the levelization approach it now suggests is inappropriate. Department witness Mark Johnson stated as follows regarding levelization in the context of uncollectible expense in that case:

> Levelization is a standard ratemaking technique that is used to set rates when a cost, such as uncollectible expense, varies significantly from year to year and is difficult to estimate. Levelization minimizes the possibility that a cost may be significantly over- or under-recovered by a utility in rates going forward.[146]

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[145] *See* Ex. 24 at 22 (S. DeMerritt Rebuttal). The OAG classifies known and measurable changes as "specific measurable cost changes due to known events that occur during or in some cases shortly after the historical test year." Ex. 151 at 16 (J. Lindell Direct).

[146] Ex. 24 at 9 (S. DeMerritt Rebuttal) (citing MERC's previous rate case, Direct Testimony of Department witness Mark Johnson at 24, Docket No. G007,011/GR-10-977) (May 3, 2011)).

The OAG also supported this levelization approach in MERC's 2010 rate case, in the surrebuttal testimony of OAG witness John Lindell.[147]

Despite the Department's position in MERC's last rate case that levelization is appropriate to minimize the possibility that uncollectible expense may be significantly over- or under-recovered by a utility, the Department has shifted its position because it believes MERC's uncollectible expense appears to be going down, rather than up. The Department is now recommending that the actual 2013 uncollectible expense ratio be used to set test year uncollectible expense.[148]

This shift in approach is unreasonable and inconsistent with Commission precedent. As previously stated, the calculation using a three year average is consistent with Commission treatment of this issue in MERC's previous rate case. As the Department recognized in MERC's last rate case, levelization through the proposed average is more reasonable because it accounts for year-to-year fluctuations.[149] Ratepayers benefit from use of a three-year average because, while actual expense may vary significantly from year to year, this approach ensures a more stable calculation. MERC's proposed levelization methodology should be adopted by the ALJ and the Commission as reasonable and consistent with prior practice in MERC's previous rate cases.

The OAG similarly asserts MERC's proposed uncollectible expense calculation is too high given the economy, the weather, and the relative price of gas.[150] Rejecting MERC's calculation methodology, the OAG selects an arbitrary proposed uncollectible expense of

[147] Ex. 24 at 22 (S. DeMerritt Rebuttal) (citing Surrebuttal Testimony of John Lindell at 6-7, Docket No. G007,011/GR-10-977 (June 30, 2011)).

[148] Ex. 217 at 39 (M. St. Pierre Direct).

[149] Ex. 24 at 9 (S. DeMerritt Rebuttal) (citing MERC's previous rate case, Direct Testimony of Department witness Mark Johnson at 24, Docket No. G007,011/GR-10-977) (May 3, 2011)).

[150] Ex. 151 at 5-6 (J. Lindell Direct).

$1.35 million.[151] Rather than basing this figure on any calculation methodology, the OAG reaches what it calls a "more reasonable" estimate based on applying an arbitrary upward adjustment to MERC's 2012 uncollectible expense. The OAG provides no analysis or support for the proposed amount of the adjustment applied to the 2012 figure, stating generally that it takes into consideration an improved economy and lower relative price of natural gas.[152] The Commission should disregard this unreasonable and seemingly arbitrary proposal by the OAG. Despite acknowledging the volatility of the debt expense from year to year,[153] the OAG's proposal fails to take into account the need to account for such volatility.

Both the Department's and OAG's recommendations are unreasonable and inconsistent with Commission precedent on this issue. MERC respectfully requests that the Commission approve its proposed calculation of uncollectable expense.

B. MERC's Costs Associated with IBS Customer Relations Expense Are Used and Useful and the Corresponding Adjustment is Reasonable.

MERC has included a K&M adjustment of $730,681 to account for increased billings from IBS-customer relations associated with MERC's third party costs from Vertex and implementation of the ICE 2016 Project.[154] Vertex provides third-party customer service functions for MERC including call center, dispatch, billing, and payment processing. The contract between MERC and Vertex for these services is for a multiple year term. The increases associated with Vertex are estimated by MERC to be $408,455 in 2014 based on fixed payments of the contract, as well as cost allocators and projected customer growth.[155] MERC's costs

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151 Ex. 151 at 7 (J. Lindell Direct).

152 Ex. 151 at 7 (J. Lindell Direct).

153 Ex. 154 at 3-4 (J. Lindell Surrebuttal).

154 Ex. 19 at 15-16 (S. DeMerritt Direct).

155 Ex. 19 at 15 (S. DeMerritt Direct).

associated with Vertex are used and useful because Vertex is currently providing third party customer service functions (call center, dispatch, billing, payment process, etc.) to MERC customers.[156] The ICE 2016 Project is a project to unify the various billing systems currently in use across the Integrys platform. The ICE 2016 Project will result in a single billing system for all six Integrys regulated utilities, which will provide benefits to MERC customers via improved efficiency and productivity resulting from the conversion of MERC's current Customer Information System technology platform onto the Open-C technology platform.[157] Additionally, the ICE 2016 Project will provide overall standardization of internal delivery processes and system technology platforms, which will improve customer satisfaction, increase productivity, and increase efficiency by lowering overall operating costs.[158] MERC has estimated known and measurable increases associated with the ICE 2016 Project for 2014 to be $322,226.[159] 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 should properly be included as a K&M adjustment to O&M expense.[160]

The OAG has taken the position that MERC's adjustment for IBS-Customer Relations should be denied based on the assertion that these costs are not "used and useful" in the provision of utility service.[161] Specifically, the OAG recommends that the entire adjustment for IBS Customer Relations expense be removed,[162] despite acknowledging that "Vertex costs are

[156] Ex. 19 at 15 (S. DeMerritt Direct).

[157] Ex. 10 at 3-4 (B. Kage Direct).

[158] Ex. 10 at 3-4 (B. Kage Direct).

[159] Ex. 19 at 16 (S. DeMerritt Direct).

[160] Ex. 10 at 3-4 (B. Kage Direct).

[161] Ex. 151 at 21 (J. Lindell Direct).

[162] Ex. 151 at 20-21 (J. Lindell Direct).

used and useful."[163] Because the OAG has expressly acknowledged that the costs associated with Vertex are used and useful, there is no question that the portion of the K&M adjustment associated with Vertex costs should properly be included in O&M expense. Contrary to the OAG's position, the ICE 2016 Project is also used and useful in the provision of utility service. As explained in the testimony of Mr. DeMerritt and Mr. Kage, the ICE 2016 Project provides specific benefits to customers.[164] The Department has not raised any concerns regarding inclusion of these costs.

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.[165]

C. MERC's Costs Associated with the Mapping Project Are Used and Useful and Reasonably Assigned in Their Entirety to 2014.

MERC has included a K&M adjustment of $330,000 associated with a mapping project, which is intended to update and verify MERC's mapping information.[166] MERC has identified gaps in the accuracy of its mapping that field personnel use to locate lines, manage outages, determine flow modeling, and other critical infrastructure tasks.[167] These inaccuracies are the result of various mapping systems having been converted and merged as companies were

[163] Ex. 151 at 20-21 (J. Lindell Direct).

[164] Ex. 24 at 25 (S. DeMerritt Rebuttal); Ex. 10 at 3-8 (B. Kage Direct).

[165] Ex. 24 at 25 (S. DeMerritt Rebuttal).

[166] Ex. 19 at 18-19 (S. DeMerritt Direct).

[167] Ex. 19 at 18 (S. DeMerritt Direct).

acquired, sold, and consolidated.[168] To improve the quality and utilization of the mapping systems, MERC plans to validate the accuracy of its mapping by verifying as built drawings and actual field data.[169] Inclusion of costs for this project in the amount of $330,000 is appropriate and reasonable for calculating MERC's test year 2014 O&M expense.

The Department recommends that the Commission reduce the K&M adjustment associated with MERC's mapping project by $220,000 because, according to Department witness Ms. St. Pierre, the mapping project is a one-time project and, therefore, the costs should be levelized over three years—the Department's recommended amortization period for rate case expense.[170] This recommendation is not reasonable and making an adjustment for a single item as proposed by the Department, with no consideration for the future costs, sales, or capital requirements of other items, would be punitive. 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.[171] The Department is effectively proposing a single item rate making adjustment for 2015 and 2016 without consideration for any future increases in MERC's overall costs.[172]

Further, 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.[173] Nevertheless, the Department's proposal to spread

[168] Ex. 19 at 18-19 (S. DeMerritt Direct).

[169] Ex. 19 at 19 (S. DeMerritt Direct).

[170] Ex. 219 at 40 (M. St. Pierre Surrebuttal).

[171] Ex. 24 at 10-11 (S. DeMerritt Rebuttal).

[172] Ex. 24 at 11 (S. DeMerritt Rebuttal).

[173] Ex. 24 at 11 (S. DeMerritt Rebuttal).

this expense amount over multiple years is unreasonable and punitive and MERC's K&M adjustment of $330,000 should be approved.

D. MERC's Costs Associated with the Sewer Laterals Pilot Program Are Used and Useful and Properly Calculated.

MERC has included a K&M adjustment for its sewer lateral legacy pilot program in the amount of $340,000 for the 2014 test year.[174] The sewer lateral program is a project that is being undertaken to comply with requests from the Minnesota Office of Pipeline Safety ("MNOPS").[175] Due to recent incidents within the industry, MNOPS has required other companies to inspect legacy installations. When performing these inspections, some companies found conflicts between gas and sewer laterals.[176] Such conflicts create a risk to the public because sewer work could result in a gas leak into the sewer system.[177] MERC's sewer lateral program is designed to determine the best practices and amount of time needed to complete an assessment of possible conflicts with sewer lines that could present a risk to customers.[178] These costs are reasonable because the ultimate goal is to ensure that MERC does not have conflicts with sewer lines that could risk customer safety.[179] Additionally, the sewer lateral program is a multi-year project that will extend beyond 2014.[180]

MERC and the Department are in agreement with respect to MERC's proposed K&M adjustment associated with the sewer lateral program. Although the Department originally

[174] Ex. 19 at 17 (S. DeMerritt Direct).

[175] Ex. 19 at 17 (S. DeMerritt Direct).

[176] Ex. 19 at 17 (S. DeMerritt Direct).

[177] Ex. 19 at 17 (S. DeMerritt Direct).

[178] Ex. 19 at 17 (S. DeMerritt Direct).

[179] Ex. 19 at 17 (S. DeMerritt Direct).

[180] Ex. 24 at 10 (S. DeMerritt Rebuttal).

concluded that the sewer lateral program was a one-time project,[181] based on information provided by MERC that the sewer lateral pilot project is a multi-year project that will extend beyond 2014 and the community of Cannon Falls, the Department is now in agreement that the Commission should accept MERC's proposed test year sewer laterals pilot program costs.[182] Inclusion of these costs is reasonable and should be approved by the ALJ and the Commission.

IX. MERC'S TRAVEL AND ENTERTAINMENT EXPENSES ARE PRUDENTLY INCURRED AND REPORTED CONSISTENT WITH MINNESOTA STATUTE.

MERC presented its prudently incurred travel, entertainment, and related expenses consistent with Minn. Stat. § 216B.16, subd. 17.[183] MERC and the Department are in agreement with respect to the appropriate level of Travel and Entertainment ("T&E") expense.[184] MERC accepted the Department's recommendation to remove $7,770 for expenses that the Department felt did not appear to be reasonably related to Minnesota regulated utility operations.[185] MERC also accepted the Department's recommendation to reduce test year Administrative and General Expense by $956 for test year corporate aircraft costs.[186] Although MERC asserts these costs are prudent, it agreed with the Department's recommended adjustment because the costs are not material.[187] Additionally, although Department witness Ms. La Plante 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 a specific recommendation with

[181] Ex. 219 at 38-39 (M. St. Pierre Surrebuttal).

[182] Ex. 219 at 38-39 (M. St. Pierre Surrebuttal).

[183] Ex. 17 at 47-50 (S. DeMerritt Direct); Ex. 4, Initial Filing Volume 3, Informational Requirement Document 14.

[184] Ex. 216 at 11 (L. La Plante Surrebuttal).

[185] Ex. 24 at 17-18 (S. DeMerritt Rebuttal).

[186] Ex. 24 at 18 (S. DeMerritt Rebuttal).

[187] Ex. 24 at 18 (S. DeMerritt Rebuttal).

respect to that issue.[188] MERC has agreed to provide all T&E expenses, including expense related to employees who work for affiliates of MERC, in future rate case filings.[189]

The OAG recommended disallowance of MERC's T&E expense in the amount of $569,450.[190] Additionally, the OAG recommended that membership dues in the amount of $63,245 be disallowed.[191] According to the OAG, these expenses were not itemized and reported as required by statute and therefore disallowance is justified.[192] Contrary to the assertions of the OAG, MERC has fully complied with the requirements of Minn. Stat. § 216B.16, subd. 17. Because 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, the ALJ and the Commission should find MERC's proposed T&E expense reasonable.

In addition to recommending an adjustment to MERC's T&E expense, the OAG also makes four recommendations for MERC's future filings related to T&E expense. First, the OAG recommends that MERC provide "better" descriptions for the business purposes of expenses.[193] MERC already provides sufficient detail to fully comply with the requirements of Minn. Stat. § 216B.16, subd. 17, and a requirement that MERC provide "better" descriptions is unnecessary and vague. The word "better" is very subjective and provides little clarity on what is expected beyond what MERC has already provided. Additional detail is not necessary to allow the parties to fully evaluate the prudence of MERC's proposed T&E expense. Second, the OAG recommends that MERC include all T&E expenses for all employees that work for affiliates of

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[188] Ex. 216 at 11, n. 1 (L. La Plante Surrebuttal).

[189] Ex. 25 at 3 (S. DeMerritt Surrebuttal).

[190] Ex. 151 at 25-26 (J. Lindell Direct).

[191] Ex. 151 at 25-26 (J. Lindell Direct).

[192] Ex. 151 at 3, 22-23 (J. Lindell Direct).

[193] Ex. 153 at 4 (J. Lindell Rebuttal).

MERC.[194] MERC has agreed to provide all T&E expense, including expense related to employees who work for affiliates of MERC, in future rate case proceedings. MERC's agreement with this recommendation is not an admission of incompleteness in this rate case.[195] MERC has fully complied with the statutory requirements, but agrees to provide this additional information in future rate cases to assist the Department and OAG with their review of T&E. Third, the OAG recommends that MERC exclude all expenses incurred outside of Minnesota, unless the description justifies an allocation to Minnesota.[196] This recommendation is unreasonable. Simply because expenses are incurred outside of Minnesota, does not justify denying recovery of those expenses.[197] An example of prudently incurred T&E expense which occurs outside of the state boarders is travel to Green Bay for MERC Board of Director meetings and training.[198] Finally, the OAG recommends that MERC allocate only a portion of T&E expenses for items not specific to Minnesota, such as Vertex travel and expense.[199] MERC agrees that such expenses will continue to be allocated based on the factors discussed in the Direct Testimony of Ms. Tracy Kupsh.[200]

[194] Ex. 153 at 4 (J. Lindell Rebuttal).

[195] Ex. 25 at 3 (S. DeMerritt Surrebuttal).

[196] Ex. 153 at 4 (J. Lindell Rebuttal).

[197] Ex. 25 at 3 (S. DeMerritt Surrebuttal).

[198] Ex. 25 at 3-4 (S. DeMerritt Surrebuttal).

[199] Ex. 153 at 4 (J. Lindell Rebuttal).

[200] Ex. 25 at 4 (S. DeMerritt Surrebuttal); Ex. 12 (T. Kupsh Direct).

X. MERC'S PROPOSED REGULATORY ASSETS AND LIABILITIES ARE PROPERLY RECORDED.

Federal Energy Regulatory Commission ("FERC") account 182.3 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*.[201]

MERC initially included $19,642,806 of regulatory assets and liabilities in its proposed test-year rate base.[202] Based on adjustments agreed to during this proceeding, MERC is now proposing to include $18,794,224 of regulatory assets and liabilities in rate base. The Department, however, has taken the position that inclusion of these regulatory assets and liabilities is not justified and that MERC should reduce rate base by $11,281,942 for regulatory asset and liability adjustments related to 17 accounts.[203] While MERC has agreed to a number of the adjustments recommended by the Department, MERC and Department continue to disagree regarding the inclusion of regulatory assets and liabilities associated with pension and benefits.

The majority of the regulatory assets and liabilities which the Department has proposed to remove from rate base are associated with employee benefits. Removal of the benefit assets and liabilities, as proposed by the Department, is not warranted. For benefits expense, MERC must make an out-of-pocket expenditure to create the asset, but the asset is then used to earn a return and offset benefit costs. Including these assets and liabilities in rate base is how shareholders are permitted to earn a reasonable rate of return on this essential activity.[204]

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[201] 18 C.F.R. § 367.1823 (emphasis added).

[202] Ex. 19 at Exhibit SSD-26 (S. DeMerritt Direct), Ex. 4, Initial Filing Volume III, Informational Requirements Document 2, Schedule B-6.

[203] Ex. 217 at 11 (M. St. Pierre Direct).

[204] Ex. 24 at 3-4 (S. DeMerritt Rebuttal).

A. MERC and the Department Have Reached Agreement Regarding the Appropriate Treatment of Non-Benefit Regulatory Assets and Liabilities.

The Department has recommended that three accounts not be removed from rate base since these accounts were specifically discussed and approved in prior Commission filings: Regulatory Asset-Purchase Accounting Effect on Benefits (Account 182351); Regulatory Asset-Cloquet Plant Amortization (Account 182901); and Regulatory Liability-2010 Health Care Legislation (Account 254391).[205] MERC agrees that inclusion of these accounts in rate base is reasonable and appropriate.

MERC and the Department have also reached agreement on the appropriate treatment of regulatory assets and liabilities in the following additional accounts, as discussed below. First, MERC has agreed that Deferred Debit-Long Term Account Receivable Arrearage, an asset of $17,066 (Account 186591) was erroneously included in rate base.[206] Second, MERC agreed that because derivative assets were excluded from rate base, Regulatory Liabilities-Derivatives, a liability in the amount of $244,050 (Account 254450) should be excluded as well.[207] In addition, MERC agreed with the Department's proposed adjustment to remove from rate base the recovery of unamortized rate case expense in the amount of $1,312,704[208] because these costs are not prepaid costs appropriate for inclusion in rate base.[209] MERC proposed an additional adjustment to remove deferred taxes associated with the removed unamortized rate case expenses, in the amount of $541,188, which the Department agreed was appropriate, but determined should be

[205] Ex. 217 at 10-11 (M. St. Pierre Direct).

[206] Ex. 24 at 4 (S. DeMerritt Rebuttal).

[207] Ex. 24 at 4-5 (S. DeMerritt Rebuttal).

[208] Ex. 216 at 4-5 (L. La Plante Surrebuttal). In Surrebuttal Testimony, Ms. La Plante recommended a revision to her recommended adjustment of unamortized rate case expense to reflect the amount allocated to Minnesota.

[209] Ex. 215 at 18 (L. La Plante Direct).

adjusted to $540,106 to reflect the amount allocated to Minnesota.[210] Finally, MERC agreed to remove certain amounts pertaining to non-qualified employee benefit costs from rate base. These amounts include accounts pertaining to the Supplemental Employee Retirement Plan ("SERP") and pension restoration. MERC has agreed to the removal of the following amounts pertaining to nonqualified employee benefit costs from rate base: $163,731 (Injuries and Damages Reserve, Account 228305) $19,719 (Supplemental Remp. Ret. Plan, SERP, Account 228305), $53,763 (Pension Restoration Account 228310), and $2,556 (Current Pension Restoration, Account 242072). Collectively this results in an increase to rate base of 239,769.[211] These proposed adjustments are reasonable and should be approved by the ALJ and the Commission.

B. Inclusion of Company Supplied Benefit Funds in Rate Base Is Reasonable and Consistent with Prior Commission Decisions.

MERC proposed to included benefit assets and liabilities in the amount of $11,769,457 in rate base to be consistent with the agreement reached with the OAG and approved by the Commission in MERC's last rate case, Docket No. G007,011/GR-10-977.[212] 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.[213] In MERC's last case, MERC did not initially include the asset and liability accounts related to current and long-term assets in its proposed rate base. However, during that proceeding, MERC agreed to the OAG's recommendation that MERC adjust rate base for ratepayer-supplied funds – the differences between MERC's actual cumulative

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210 Ex. 216 at 3-5 (L. La Plante Surrebuttal); Ex. 24 at 17 (S. DeMerritt Rebuttal).

211 Evidentiary Hearing Transcript (May 13, 2014) at 56 (C. Hans); Ex. 27 at Exhibit CMH-4 (C. Hans Rebuttal).

212 Ex. 27 at 13, 17 (C. Hans Rebuttal).

213 Ex. 27 at 14 (C. Hans Rebuttal).

contributions to benefit trusts and the cumulative expense recognized by MERC.[214] In that proceeding, cumulative funding for other post-retirement benefits exceeded the recognized expense by $56,468; and cumulative funding for pension benefits was less than the recognized cumulative expense by $127,637.[215] The net result was a reduction to rate base of $71,159.[216]

Proper regulatory accounting requires consistency. If the regulatory accounting of this matter was appropriate in the prior case, it should and must be appropriate in this case. MERC proposes to treat its asset and liability accounts related to long-term assets identically in this proceeding by including them in rate base. Inclusion of the difference between cumulative funding and cumulative expense is consistent with the approach taken in the prior case.[217] MERC proposes to include cumulative excess funding in the amount of $11,769,457 in rate base for pre-payment on pension expense and other post-retirement benefits.[218]

Department witness Ms. St. Pierre argued that this cumulative excess funding should not be included in rate base because, according to Ms. St. Pierre, the retirement benefits trust plan assets may go up or down depending on funding and market conditions.[219] The Department characterizes this as a "temporary timing difference" which, according to the Department, does not justify rate base recovery.[220] The Department's recommendation is both inconsistent with prior treatment and potentially detrimental to MERC's customers.

[214] Ex. 27 at 15 (C. Hans Rebuttal).

[215] Ex. 27 at 15 (C. Hans Rebuttal).

[216] Ex. 27 at 15 (C. Hans Rebuttal).

[217] Ex. 27 at 15 (C. Hans Rebuttal).

[218] Ex. 27 at 17 (C. Hans Rebuttal).

[219] Ex. 217 at 9 (M. St. Pierre Direct).

[220] Ex. 217 at 9 (M. St. Pierre Direct).

First, MERC's treatment in this rate case is consistent with the treatment in MERC's prior rate case, Docket No. G007,011/GR-10-977.[221] While MERC did not include cumulative funding and cumulative expense in its initial filing, MERC ultimately agreed to include it in its rate base based on recommendation of the OAG, which the Department did not oppose.[222] Second, as demonstrated in Ms. Hans's Rebuttal Testimony, the facts and circumstances in this rate case do not support the reduction proposed by the Department; MERC has pre-paid its pension expense during the 2012 – 2014 period by almost $12 million.[223] Third, contributions made to the pension and other post-retirement benefit trusts benefit MERC's ratepayers. These contributions are used in the calculation of net periodic benefit cost, which resulted in reduced pension costs for the 2014 test year of approximately $1.1 million and reduced test-year costs for other post-retirement benefits costs of approximately $0.1 million.[224] Even though MERC cannot withdraw the prepaid pension asset or otherwise use it, the earnings on the asset are considered income to the utility, which reduce the overall revenue requirement, thereby benefiting ratepayers. Finally, the Commission has authorized the inclusion of prepaid pension contributions in rate base as part of overall settlement.[225] 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

[221] Ex. 27 at 15 (C. Hans Rebuttal).

[222] Ex. 27 at 15 (C. Hans Rebuttal).

[223] Ex. 27 at 15-16 (C. Hans Rebuttal).

[224] Ex. 27 at 16 (C. Hans Rebuttal).

[225] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-10-971, Finding of Fact, Conclusions and Order (May 14, 2012).

claimed pension expense amount, which was included as part of a larger settlement.[226] 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 Department also erroneously asserts that inclusion of cumulative excess funding related to benefits accounts in both the lead/lag study (or cash working capital, as also referred to by Ms. St. Pierre) and in rate base could result in double recovery, and, as a result, the amounts should not be included in rate base.[227] This assertion is simply wrong. The purpose of the lead/lag study is to measure the difference in time frames between (1) the time service is rendered until revenue for that service is received, lead, and (2) the time that labor, materials, or services are used in providing service until expenditures for those items are made, lag.[228] The regulatory assets and liabilities are not a function of benefit expenses, such as other working capital accounts. Instead, it is the other way around. Benefit expenses are a function of the assets and liabilities. Typically, the greater the return on the assets, the lower the benefit expense MERC recognizes on its income statement.[229]

An understanding of the distinction between the recording of benefit expenses versus accounts payable account is in order. For accounts payable, MERC recognizes an expense on its income statement at the time of the purchase of materials and supplies, but the invoice itself may not be paid until a later date, hence the booking to a liability account (accounts payable).[230] The

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[226] *In the Matter of the Application of Northern States Power Company, a Minnesota corporation for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-12-961, Xcel Energy Brief at 138-39 (May 15, 2013).

[227] Ex. 219 at 6 (M. St. Pierre Surrebuttal).

[228] Ex. 19 at 33 (S. DeMerritt Direct).

[229] Ex. 24 at 3-4 (S. DeMerritt Rebuttal).

[230] Ex. 24 at 3 (S. DeMerritt Rebuttal).

lead/lag study calculates the delay in payment and accounts for the liability, or reduction in rate base, for that accounts payable expense.[231] 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.[232] MERC notes 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.[233] Instead, including these assets and liabilities in rate base is how shareholders earn a return on this funding activity.[234] 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.

Finally, while MERC has shown that its treatment of regulatory assets and liabilities is reasonable based on the above discussion and supporting testimony, MERC notes that if the Commission ultimately removes the assets and liabilities associated with the benefit plans, then proper accounting would dictate the corresponding deferred taxes also should also be removed from rate base.[235]

XI. MERC'S PROPOSED TEST YEAR EMPLOYEE BENEFIT COSTS REPRESENT MERC'S REASONABLE COST OF DOING BUSINESS.

In total, MERC's forecast of employee benefit costs for the 2014 test year is $4,744,538, including allocation of employee benefit costs from IBS. This compares to $5,017,342 for the

[231] Ex. 24 at 3 (S. DeMerritt Rebuttal).

[232] Ex. 24 at 3 (S. DeMerritt Rebuttal).

[233] Ex. 24 at 4 (S. DeMerritt Rebuttal).

[234] Ex. 24 at 4 (S. DeMerritt Rebuttal).

[235] Ex. 24 at 4 (S. DeMerritt Rebuttal).

2012 historic year. This is a decrease of $272,804 or 5.4% over a two-year period (corresponding to a decrease of 2.66% per year).[236]

MERC and the Department have come to agreement on several issues related to employee benefits. First, MERC and the Department have agreed that certain employee benefit costs will not be included in rate recovery.[237] Second, the Department agreed with MERC's proposal that non-qualified pension plan costs authorized by the Commission in Docket No. G-007,011/M-06-1287 should be included in rate recovery.[238] Third, MERC and the Department agreed that the actuarially-determined costs should be based on the most recent data available. Department witness Ms. St. Pierre recommended that the plan asset values be updated to reflect balances as of December 31, 2013.[239] For the pension and post-retirement life insurance plan, MERC agreed to use the plan asset values as of December 31, 2013. However, for the post-retirement medical plan, MERC proposed to update the plan asset values as of March 1, 2014, which the Department has agreed is appropriate.[240] Fourth, as shown in Exhibit CMH-1 to Ms. Hans' Direct Testimony, for the sub-accounts on lines 15 through 29, the Department did not dispute the cost projections proposed based on inflating 2012 actual amounts.[241]

The only area of continuing disagreement between MERC and the Department with respect to MERC's proposed employee benefit expense is the appropriate assumptions to be applied to the actuarial analysis of benefit costs. MERC's proposed employee benefit expense

236 Ex. 26 at 3 (C. Hans Direct); Ex. 217 at 28 (M. St. Pierre Direct). MERC does not request recovery in 2014 of costs recorded in Accounts 926210 (Pension Restoration Plan Expense), 926220 (Supplemental Employee Retirement Plan ("SERP")), and 926300 (Executive Deferred Compensation Employee Stock Ownership Plan Match) for MERC's share of IBS's current costs related to non-qualified benefits. Ex. 26 at 4-5 (C. Hans Direct).

237 *See* Ex. 26 at 4 (C. Hans Direct).

238 Ex. 217 at 10 (M. St. Pierre Direct).

239 Ex. 219 at 25 (M. St. Pierre Surrebuttal).

240 Ex. 27 at 5 (C. Hans Rebuttal); Ex. 219 at 25-26 (M. St. Pierre Surrebuttal).

241 Ex. 26 at 7-8 (C. Hans Direct).

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. For ratemaking purposes, the discount rate used to calculate expense should be based on the specific characteristics of the plan and should be updated to represent the most current information available.[242] Although the Commission has determined that neither accounting standards, nor federal employee benefits regulations, are determinative for ratemaking purposes, the facts presented in the record with respect to MERC's pension and other employee benefits plans fully support the use of the discount rates proposed by MERC for calculation of test-year benefit expense. These proposed discount rates are individually determined based on each plan and are carefully scrutinized by MERC's external auditors.

MERC's filing included test year pension plan expense, post-retirement medical plan expense, and post-retirement life plan expense determined based on the actuarial expense determined using GAAP, under Accounting Standards Codification ("ASC") requirements: Pension Expense: ASC 715-30 Defined Benefits Plans – Pension (formerly Statement of Financial Accounting Standards ("FAS") 87); Post-Retirement Medical Expense and Post-Retirement Life Plan Expense: ASC 715-60 Defined Benefit Plans – Other Postretirement (formerly "FAS 106").[243] The Company's employee benefit expenses are calculated by the Company's outside actuaries, Towers Watson.

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[242] Ex. 27 at 8-12 (C. Hans Rebuttal).

[243] Ex. 26 at 9, 13-15 (C. Hans Direct).

MERC witness Ms. Christine Hans testified that Towers Watson performed the calculations in accordance with ASC 715-30 and ASC 715-60 to determine the actuarially calculated costs and then MERC's external auditors, Deloitte and Touche, reviewed the actuarial assumptions to ensure consistency with GAAP.[244] Ms. Hans explained that the costs under both ASC 715-30 and ASC 715-60 are determined by the actuary based upon its review of: (1) employee census data; (2) current plan provisions; (3) plan asset performance; and (4) certain other actuarial assumptions.[245] Further, under both ASC 715-30 and ASC 715-60, there are four components of the calculated expenses: (1) service cost; (2) interest cost; (3) expected earnings on plan assets; and (4) amortization of gains and losses, prior service costs, and any transitional amounts.[246] In order to calculate the plan's total benefit obligation and annual pension expense under ASC 715-30, the actuary used assumptions that included: (1) mortality tables; (2) retirement rates from MERC; (3) anticipated salary increases; (4) expected return on plan assets; and (5) a discount rate.[247]

The assumptions used for MERC's Expected Long-Term Rate of Return are determined based on the requirements of ASC 715 and the Employee Retirement Income Security Act ("ERISA"). ASC 715 requires that the Expected Long-Term Rate of Return assumptions reflect the "average rate of earnings expected on the funds invested to provide for the benefits included in the projected benefit obligation." MERC used an expected rate of return of eight percent to calculate pension and other employee benefit plan expense and the Department accepted this assumption.[248] The discount rate, in contrast, is an interest rate used to adjust for the time value

244 Ex. 26 at 9, 13-15 (C. Hans Direct).

245 Ex. 26 at 9, 13-14 (C. Hans Direct).

246 Ex. 26 at 9-10, 14 (C. Hans Direct).

247 Ex. 26 at 10-11 (C. Hans Direct).

248 Ex. 26 at 10-11, 14-15 (C. Hans Direct); Ex. 217 at 34 (St. Pierre Direct).

of money.[249] ASC 715 requires that the discount rate be set at rates where pension benefits 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.[250]

MERC and the Department disagree on the assumptions that should be used to calculate pension and post-retirement life costs for the 2014 test year. The Department accepted MERCs proposed calculation of post-retirement medical expense, concluding that MERC should not be required to update post-retirement costs for the Department's discount position in this case.[251] According to Department Witness Ms. St. Pierre, "Actuarial updates are costly and the test-year post retirement costs are not high."[252] However, the Department disagreed with MERC's use of a discount rate independent of the expected return on assets for calculation of pension expense and post-retirement life insurance expense.[253]

MERC believes that its actuarial determination of its pension and post-retirement life plan costs, based on actual December 31, 2013 discount rates,[254] are the most accurate measure of MERC's 2014 test-year costs and should therefore be used. As explained in the testimony and exhibits of Ms. Hans, the appropriate discount rate to use to value costs should be independently calculated and not arbitrarily set equal to the assumed return on plan assets, as suggested by the

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[249] *See* Ex. 27 at 8-9 (C. Hans Rebuttal).

[250] Ex. 27 at 8-9 (C. Hans Rebuttal).

[251] Ex. 219 at 32-33 (M. St. Pierre Surrebuttal).

[252] Ex. 219 at 32 (M. St. Pierre Surrebuttal).

[253] Ex. 219 at 32-33 (M. St. Pierre Surrebuttal).

[254] On January 27, 2014, MERC received an updated actuarial analysis for the 2014 test year from Towers Watson, its independent actuary. This updated analysis reflects the plan asset values and discount rates as of December 31, 2013. On March 25, 2014, MERC received an updated actuarial analysis from Towers for the post-retirement medical plans. This updated analysis was triggered as a result of a change to the plans and reflects the plan asset values and discount rates as of March 1, 2014. Ex. 27 at 5 (C. Hans Rebuttal).

Department.[255] The specific facts and circumstances relevant to MERC's pension and other employee benefit plans do not support using an eight percent discount rate for calculation of test year expense.

MERC proposed the following discount rates to be used in calculating test-year benefit expense in the updated actuarial analysis summarized in the Rebuttal Testimony of Ms. Hans:[256]

Pension Plan	4.25%	As of December 31, 2013
Post-retirement medical—administrative plan	4.05%	As of March 1, 2014
Post-retirement medical—non-administrative plan	4.80%	As of March 1, 2014
Post-retirement medical—Peoples Energy Medical	4.45%	As of March 1, 2014
Post Retirement Life	4.80%	As of December 31, 2014

The Department, while acknowledging generally the value of using an actuarial determination of costs, arbitrarily recommended that test-year actuarially-determined pension and post-retirement life expense be based on a discount rate set equal to the long-term growth rate, at eight percent.[257] The Department's recommendations, if adopted, would not accurately reflect MERC's reasonable costs of doing business. The Department's recommendation that the discount rate be set equal to the long-term growth rate goes against the defined purpose of the actuarial analysis and the stated intent of the Commission in determining costs, to get as accurate a reflection as possible of the costs.

The Department erroneously argues that MERC's discount rates may be too low "because the rates were less than the expected return on the plan assets."[258] While acknowledging that the appropriate level of expense in rates "must reflect the likely and reasonable expense going

255 Ex. 27 at 9-12 (C. Hans Rebuttal).

256 Ex. 27 at 5-6 (C. Hans Rebuttal).

257 Ex. 217 at 34 (M. St. Pierre Direct).

258 Ex. 217 at 30 (M. St. Pierre Direct).

forward until the Company's next rate case,"[259] the Department proposes that expense be based on use of an arbitrary discount rate rather than a rate reflecting the specific facts and circumstances relevant to the benefit plans. The Department also points to Xcel Energy's 2012 rate case, in Docket No. E002/GR-12-961, as somehow supporting the notion that the discount rate and the expected return on plan asset used to determine test-year pension expense should be equal.[260]

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.[261] 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 requires the use of the Unit Credit Method.[262] The Unit Credit Method is based on the present value of accrued benefits using corporate bond yields.[263]

Ms. Hans explained in her testimony that, in order to get the most accurate calculation of expense, the appropriate discount rate should be independently calculated and not just set equal to the assumed return on plan assets.[264] The discount rate and the expected return on plan assets

[259] Ex. 219 at 29 (M. St. Pierre Surrebuttal).

[260] Ex. 217 at 30 (M. St. Pierre Direct); Ex. 219 at 29-30 (M. St. Pierre Surrebuttal).

[261] Ex. 27 at 10-11 (C. Hans Rebuttal).

[262] Ex. 27 at 10 (C. Hans Rebuttal).

[263] Ex. 27 at 10 (C. Hans Rebuttal).

[264] Ex. 27 at 8-9 (C. Hans Rebuttal).

are independently determined in accordance with GAAP, and the discount rates determined for each plan are based on the specific expected benefit payments for the plan.[265]

The facts and circumstances surrounding the MERC plans are not similar to NSPM or XES. An attempt to draw a comparison among the plans does not survive scrutiny and is unreasonable. Further, in Docket No. E002/GR-12-961, the ALJ took issue with Xcel's failure in distinguishing the Xcel and NSPM plans and, thus, the discount rates were treated the same.[266] Here, MERC has explained in detail why its discount rate determinations are reasonable, the best method for calculating the discount rate, and distinguishable from the plan under consideration in Xcel's 2012 rate case.

More recently, the Commission concluded that a blanket rule of calculating employee benefit expense using a discount rate equal to the expected return on plan assets was not appropriate. Specifically, in CenterPoint Energy's most recent rate case, Docket No. G-008/GR-13-316, the Commission rejected the ALJ's recommendation that test year employee benefit expense be calculated using 7.25% for both the long-term growth rate and the discount rate.[267] The ALJ reasoned that setting the two rates to the same figure was consistent with the Commission's decision in the 2012 Xcel Energy rate case.[268] In deciding not to adopt the ALJ's recommendation, the Commission concluded: "The calculation of pension expenses requires actuarial assumptions appropriate to the factual circumstances in each case. The factual record that resulted in the discount rate determination in the Xcel rate case does not pertain to the pension expense calculation here."[269] While acknowledging that the Commission is not bound to

[265] Ex. 27 at 9 (C. Hans Rebuttal).

[266] *See* Ex. 27 at 10 (C. Hans Rebuttal).

[267] CPE Findings of Fact, Conclusions, and Order at 11 (cited initially in note 76).

[268] CPE Findings of Fact, Conclusions, and Order at 11-12.

[269] CPE Findings of Fact, Conclusions, and Order at 12.

follow the accounting standard or federal pension funding laws in calculating employee benefits expense for ratemaking purposes, the Commission determined the appropriate discount rate for calculation of benefits expense must be supported by the factual record.[270] The Commission concluded that the historical five-year average discount rate of 5.35% would be most appropriate for calculating pension expense with respect to CenterPoint. In support of this conclusion, the Commission noted:

> The appropriate discount rate continuously varies, but changes are only reflected in utility rates periodically—when a rate case is decided. The Company's proposed discount rate is markedly lower than average. For rate setting purposes, in this case, it is appropriate to use a historical average to buffer the effect the recently-below-average discount rate would have on the overall test-year pension expense. Under these conditions, a discount rate based on the five-year average is more reasonable than a discount rate determined at a single point in time, the timing governed by Company's choice to initiate a rate case.[271]

The facts presented in the record here fully support MERC's proposed discount rates for calculation of pension and other employee benefit expenses. First, based on the above description, MERC has demonstrated that its pension is not similar to the pension plans at issue in Xcel's 2010 rate case.[272] Second, MERC's proposed discount rate calculations are most appropriate because they were calculated based on real market conditions. MERC calculated the relevant discount rate by selecting an actual bond portfolio to settle each plan's expected future benefit payments.[273] The model used theoretically purchases individual high-quality corporate bonds to settle each plan's expected future benefit payments.[274] From the theoretically

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[270] CPE Findings of Fact, Conclusions, and Order at 12.

[271] CPE Findings of Fact, Conclusions, and Order at 12.

[272] *See supra* notes 258-270 and accompanying text.

[273] Ex. 27 at 9 (C. Hans Rebuttal).

[274] Ex. 27 at 9 (C. Hans Rebuttal).

purchased bonds, a single rate is determined that equates the market value of the bonds purchased to the discounted value of each plan's expected future benefit payments.[275] The calculated discount rate is then rounded to the nearest 5 basis points.[276] MERC's assumptions are carefully selected in consultation with its actuary and are reviewed and approved by external auditors. It is unreasonable for the Department to suggest arbitrarily setting a discount rate that it equal to the return on plan assets with little more support than the fact that such a method has been reasonable in one other factually dissimilar rate case. In fact, to set the discount rate at the level proposed by the Department could ultimately result in increased costs to MERC.[277] The Department has presented no actuarial or other analysis that supports its discount rate conclusions. In contrast, the record reflects MERC has performed a thorough analysis in setting its discount rate, which should be adopted.

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.

In the current case, it is not appropriate for MERC to use the eight percent discount rate suggested by the Department because, based on the current economic conditions with high quality corporate bonds, an eight percent discount rate far exceeds what would be considered reasonable.[278] It would only be reasonable for the discount rate to equal the expected return on

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[275] Ex. 27 at 9 (C. Hans Rebuttal).

[276] Ex. 27 at 9 (C. Hans Rebuttal).

[277] Ex. 27 at 11 (C. Hans Rebuttal).

[278] Ex. 27 at 11 (C. Hans Rebuttal).

plan assets if the underlying economics used to determine the rates independently produced the same results.[279] In order for the expected return on plan assets to align with the discount rate, the investment strategy for the plan assets would have to shift significantly away from the equity allocation, significantly increasing the position in the fixed income investments and, thus, MERC's expected return on plan assets would decrease significantly from the eight percent currently used.[280] A decrease in this assumption would increase the pension and other employee benefit costs.[281]

As described above and in testimony, MERC's assumptions for the actuarially-determined pension and other employee benefit costs, including MERC's proposed discount rates, are supported by independent accounting standards and have been carefully analyzed by MERC's external auditors and should, therefore, be adopted by the ALJ and the Commission. The relevant conditions that affect pension costs are captured in the required components of the ASC 715-30 and the assumptions used by Towers Watson to determine the plan's total benefit obligation. The Department's proposal of setting the discount rate and expected return on plan assets to equal levels is not supported by the facts or circumstances here and the resulting calculation of expense would not accurately reflect MERC's reasonable costs of doing business.

"[U]nder normal ratemaking policy, a utility is entitled to recovery of necessary, ongoing expenses incurred in the business of providing utility service."[282] Employee benefit expense are one such ongoing expense and recovery of those costs as requested in this case are necessary for MERC to recover the cost of serving its Minnesota customers. The Commission has emphasized

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279 Ex. 27 at 11 (C. Hans Rebuttal).

280 Ex. 27 at 11 (C. Hans Rebuttal).

281 Ex. 27 at 11 (C. Hans Rebuttal).

282 *In the Matter of a Request of Interstate Power Co. For Authority To Change Its Rates For Gas Serv. In Minn.*, 559 N.W.2d 130, 134 (Minn. App. 1997), affirmed 574 N.W.2d 408 (Minn. 1998).

that the goal of ratemaking is to reflect *actual costs as accurately* as possible. To do so, the Commission has stated that it is "important to find the *most accurate* cost-measurement tools available." To determine which "tools are the *most accurate* in a given case is a fact-specific inquiry, and the answers vary from case to case."[283] In this case, MERC's actuarially determined pension costs, which reflect the new market realities that MERC and many other companies face, is the most accurate cost-measurement tool available.

XII. MERC'S NON-EXECUTIVE AND EXECUTIVE INCENTIVE COMPENSATION ARE CONSISTENT WITH THE INCENTIVE COMPENSATION APPROVED IN MERC'S 2010 RATE CASE AND SHOULD BE APPROVED.

MERC requested recovery of 100 percent of its non-executive incentive plan compensation and 30 percent of its executive incentive plan compensation.[284] MERC's request for recovery of 100 percent of its non-executive plan compensation is proper and is consistent with the Commission's approval of MERC's non-executive compensation package in the Company's 2010 rate case.[285]

Also consistent with MERC's 2010 rate case, the Company proposed to recover 30 percent of costs recovered in rates for executive incentive compensation.[286] The Department recommended a $27,857 reduction to general expense for MERC's executive incentive compensation costs. The Department also recommended that MERC retain the existing incentive compensation refund mechanism.[287] MERC agreed with the Department's

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[283] *See In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 26 (Nov. 2, 2010); *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rate for Electric Service in Minnesota,* Docket E-017/GR-10-239, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 27 (April 25, 2011).

[284] Ex. 13 at 11-12 (N. Cleary Direct).

[285] Ex. 13 at 4 (N. Cleary Direct).

[286] Ex. 13 at 12-13 (N. Cleary Direct).

[287] Ex. 217 at 37 (M. St. Pierre Direct).

recommendations, 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.[288]

MERC seeks non-executive and executive compensation in this rate case that is consistent with the compensation the Company sought in the 2010 rate case. In addition, MERC has agreed with the Department's recommendations regarding the calculation of non-executive and executive compensation. Therefore, the Commission should approve MERC's proposed recovery of non-executive and executive compensation costs in this rate case.

XIII. A TWO YEAR AMORTIZATION PERIOD FOR RATE CASE EXPENSE IS REASONABLE GIVEN THE PROBABILITY MERC WILL FILE ITS NEXT RATE CASE IN 2015 USING A 2016 TEST YEAR.

To calculate rate case expense, MERC has forecasted the balances of its 2011 rate case expense to be fully amortized in December 2013. MERC then projected amortization of the costs of this current rate case over a two year period beginning in January 2014.[289] MERC initially forecasted total rate case expense of $1,715,000 — $1,504,055 of which MERC proposed to include as attributable to MERC's utility operations. The types of expenses included in rate case expense are costs for MERC's capital expert, legal fees, third party requests, state agency and ALJ fees, newspaper notices, and travel expenses.[290] The Department recommended that $21,925 of MERC's travel expenses be removed from the proposed test year rate case expense,[291] and MERC accepted this adjustment.[292] MERC and the Department are in agreement on the amount of MERC's proposed amortized rate case expense but do not agree on

[288] Ex. 24 at 8, 14 (S. DeMerritt Rebuttal).

[289] Ex. 19 at 9 (S. DeMerritt Direct).

[290] Ex. 19 at 27 (S. DeMerritt Direct).

[291] Ex. 215 at 14 (L. La Plante Direct).

[292] Ex. 24 at 15 (S. DeMerritt Rebuttal).

the appropriate period of amortization. MERC proposed an amortization period of two years, while the Department recommended an amortization period of three years.[293]

A two-year amortization period is appropriate and should be adopted in this case because MERC 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.[294] The Department's recommendation of a three year amortization period inappropriately used simple averaging and was based on a very narrow history of MERC rate cases. The Department has acknowledged that estimating a reasonable amortization period is difficult because many things can impact a utility's decision to file a rate case.[295] MERC has submitted testimony to support the use of a two year amortization period based on the possibility that MERC may file a rate case in 2015 using a 2016 test year.[296]

The Department provides no factual support for its recommendation, and instead relies solely on an averaging of a limited sample of MERC's past rate filings. Specifically, the Department averaged the time between MERC's 2008 and 2010 rate cases (two years), and MERC's 2010 and 2013 rate cases (three years), and came up with an average of 2.5 years between rate cases.[297] Even if the Commission were to adopt an averaging approach, rounding down to two years makes as much sense as rounding up to three years, given the limited sample size. The Department undercuts its own argument when Ms. La Plante states that "estimating a reasonable amortization period is difficult because many things can impact the utility's decision to file a rate case. Inflation, cost-of-money, construction activity, and customer's usage and

293 Ex. 19 at 27 (S. DeMerritt Direct); Ex. 215 at 16 (L. La Plante Direct).

294 Evidentiary Hearing Transcript (May 13, 2014) at 22 (S. DeMerritt).

295 Ex. 24 at 15-16 (S. DeMerritt Rebuttal); Ex. 215 at 15 (L. La Plante Direct).

296 *See* Evidentiary Hearing Transcript (May 13, 2014) at 22 (S. DeMerritt); Ex. 24 at 16 (S. DeMerritt Rebuttal).

297 Ex. 215 at 15-16 (L. La Plante Direct); Ex. 24 at 15 (S. DeMerritt Rebuttal).

accounting changes are among the factors."[298] MERC has clearly asserted in its testimony that it anticipates a 2015 rate case filing using a 2016 test year due to increased construction activity.[299] Based on this reasoning, which the Department has acknowledged is a contributing factor in determining an appropriate amortization period, MERC believes a two year amortization period is most appropriate and should be adopted in this case.

XIV. MERC'S LEAD/LAG STUDY ACCURATELY CALCULATES CASH WORKING CAPITAL AND SHOULD BE APPROVED IN THIS RATE CASE.

MERC performed a lead/lag study to determine the cash working capital component of working capital.[300] As endorsed in the Commission's cash working capital policy, MERC's study separated expenses into components that have similar characteristics and payment patterns.[301] Even though MERC's 2012 actual cash working capital balance was $288,800 compared to the working capital balance calculated in the lead/lag study of ($3,916,174), a total reduction of rate base of $4,204,974, MERC accepts the lead/lag study results for establishing rates in this case.[302]

The Department agreed with MERC's cash working capital approach in this rate case.[303] For future rate cases, the Department recommended that MERC: (1) provide a schedule that reconciles the expense in cash working capital to the expense in MERC's test year income statement and (2) base the cash working capital schedule on the number of days rather than percentages.[304] MERC accepted both of these recommendations and agreed to the Department's

[298] Ex. 215 at 15 (L. La Plante Direct).

[299] Ex. 24 at 16 (S. DeMerritt Rebuttal).

[300] Ex. 19 at 33 (S. DeMerritt Direct).

[301] Ex. 19 at 38-39 and Schedule (SSD-21) (S. DeMerritt Direct).

[302] Ex. 19 at 40 (S. DeMerritt Direct).

[303] Ex. 217 at 50-51 (M. St. Pierre Direct).

[304] Ex. 217 at 54 (M. St. Pierre Direct); Ex. 219 at 43 (M. St. Pierre Surrebuttal).

proposed methodology for future rate case reporting.[305] MERC and the Department agree that the final cash working capital amount remains in flux until other items in the revenue deficiency calculation are resolved.[306] The Commission should approve MERC's cash working capital adjustment in this rate case, pending resolution of the revenue deficiency calculation.

XV. MERC'S PROPOSED RATE DESIGN IS REASONABLE

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.

According to these statutory sections set forth above, rates should be reasonable and not unreasonably discriminatory. Rates cannot unreasonably discriminate either by class or by

305 Ex. 24 at 12 and Schedule (SSD-4) (S. DeMerritt Rebuttal).

306 Ex. 24 at 12 (S. DeMerritt Rebuttal); Exs. 217-18 at 51 and Schedule (MAS-8) (M. St. Pierre Direct); Ex. 219 at 44 (M. St. Pierre Surrebuttal).

person.[307] In addition, Minnesota statutes encourage a rate design that favors energy conservation and reasonable use of renewable energy.[308] Finally, Minnesota statutes require that "any doubt as to reasonableness should be resolved in favor of the consumer."[309]

In this proceeding, the Department articulated four goals of rate design that it used to evaluate MERC's proposal:

1. Rates should be designed to provide the Company a reasonable opportunity to recover all prudently incurred costs, including the cost of capital;
2. Rates should be designed to promote an efficient use of resources;
3. Rate changes should be gradual to limit rate shock to consumers; and
4. Rates should be understandable and easy to administer.[310]

These four rate design goals assist in setting reasonable rates that recognize the interests of both the utility and its shareholders, and the interests of the utility's customers.

MERC and the Department are in agreement with respect to rate design and the appropriate amount of customer charges for each customer class. MERC accepted the Department's proposed apportionment of revenue responsibility with some slight modifications, which were agreed to by the Department.[311] Specifically, MERC recommended, and the Department agreed, to maintain proposed rates for the Super Large Volume customer class and Flex customer class and to group customers within the same distribution rates together for revenue apportionment purposes.[312]

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[307] Ex. 203 at 4 (S. Peirce Direct).

[308] MINN. STAT. §§ 216B.03 and 216C.05.

[309] MINN. STAT. § 216B.03.

[310] Ex. 203 at 2 (S. Peirce Direct).

[311] Ex. 205 at 2-3 (S. Peirce Surrebuttal).

[312] Ex. 205 at 2-3 (S. Peirce Surrebuttal).

A. The Residential Customer Charge Should Be Increased to $9.50 Per Month.

MERC's existing residential customer charge is $8.50 per month. MERC initially proposed to increase the monthly residential customer charge to $11.00 per month.[313] The Department recommended raising the residential customer charge to $9.50 per month.[314] The Department reasoned that the increase to $9.50 would move the residential customer charge slightly closer to cost, would slightly reduce intra-class subsidies, and is in line with the Department's recommendation in CenterPoint Energy's recent rate case, Docket No. G008/GR-13-316.[315] MERC accepted the Department's recommendation that the residential customer charge be increased to $9.50.[316]

The OAG recommended retaining the existing residential customer charge of $8.50.[317] 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.[318] The OAG also assumed, incorrectly, that any increase to the residential or Small C&I customer charge is unnecessary because MERC has full decoupling which assures collection of its fixed costs of providing service.[319] Contrary to the OAG's arguments, however, MERC does not have full decoupling for Residential and Small C&I customers. MERC's decoupling mechanism, which only applies to distribution revenues less the Conservation Cost Recovery Charge

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[313] Ex. 40 at 10 (G. Walters Direct).

[314] Ex. 203 at 16 (S. Peirce Direct).

[315] Ex. 203 at 16-17 (S. Peirce Direct).

[316] Ex. 42 at 6-8 (G. Walters Rebuttal).

[317] Ex. 150 at 46-47 (V. Chavez Direct); Ex. 154 at 15-16 (J. Lindell Surrebuttal).

[318] Ex. 154 at 15-16 (J. Lindell Surrebuttal).

[319] Ex. 154 at 16 (J. Lindell Surrebuttal).

(“CCRC”), is a use per customer calculation and includes a 10% symmetrical cap on distribution revenues.[320]

The following chart shows that the current and proposed residential customer charges (as agreed upon by the Department and MERC) are below the cost of service.[321]

Current Customer Charge-Residential	Customer Charge Agreed to by MERC and the Department	Customer Charge Justified by the CCOSS
$8.50	$9.50	$25.53

As shown in the table above, the residential customer charge, including the proposed change, is well below the actual cost of services for the residential customer class. Because the customer charges are below the customer cost, it is necessary to recover the unrecovered customer costs through the distribution charge. As a result, customers with higher than average usage pay more than their proportional share of these costs. A higher customer charge to recover fixed costs will minimize the over or under collection of costs from different customers within a class. Therefore, the proposed increase in the residential customer charge will help to alleviate this interclass subsidy.[322]

A higher customer charge 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.[323] Further, gas distribution is a unique service in which a product is provided to a customer’s door and available on demand. 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

[320] Ex. 24 at 27 (S. DeMerritt Rebuttal).

[321] Ex. 40 at 11, 16 (G. Walters Direct); Ex. 42 at 6-8 (G. Walters Rebuttal).

[322] Ex. 40 at 13 (G. Walters Direct); Ex. 42 at 6-7 (G. Walters Rebuttal); Ex. 203 at 7-8, 12 (S. Peirce Direct).

[323] Ex. 40 at 12-13 (G. Walters Direct).

charge. Without 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.[324]

An increase in the residential customer charge to $9.50 per month appropriately assigns costs to those classes and avoids rate shock. MERC's proposed residential customer charge, as agreed to by the Department, is reasonable and should be approved.

B. MERC's Proposed Customer Charges for Larger Customers Should Be Adopted.

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.[325] In addition, MERC 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.[326] The CCOSS showed the actual administrative costs to be $110.11.[327] The Department agreed with all of MERC's proposed customer charges for large customer classes, as summarized in the following table:

	Current Charge	Proposed Charge	Agreed to by Department
Small Vol. C&I	$14.50	$18.00	$18.00
Large Vol. C&I	$35.00	$45.00	$45.00
Small Vol. Interruptible &	$150.00	$165.00	$165.00
Large Vol. Interruptible &	$175.00	$185.00	$185.00
Flex Rate	$175.00	$185.00	$185.00
Super Large Volume	$300.00	$350.00	$350.00

324 Ex. 40 at 11-13 (G. Walters Direct); Ex. 42 at 8-9 (G. Walters Rebuttal).

325 Ex. 40 at 16, (G. Walters Direct).

326 Ex. 40 at 22-24 and Schedules (GJW-1) at Schedules 1 and 2 (G. Walters Direct).

327 Ex. 40 at 24 (G. Walters Direct).

No party provided testimony regarding MERC's proposal to increase the transportation administration fee from $70.00 to $110.00.[328]

The OAG recommended no increase to the customer charge for the Small C&I class, for the same reasons the OAG opposed the increase to the residential customer charge.[329] As with the residential customer charge, the current and proposed Small C&I customer charges (as agreed upon by the Department and MERC) are below the cost of service.[330] As discussed above with respect to the proposed residential customer charge, the proposed increase in the Small C&I customer charge will help to alleviate interclass subsidies and move costs closer to actual cost.[331] The proposed $18.00 customer charge for Small C&I customers will move the existing customer charge from its current 52% of actual cost of service to 65% of the cost of service for MERC.[332]

Current Customer Charge-Small C&I	Customer Charge Agreed to by MERC and the Department	Customer Charge Justified by the CCOSS
$14.50	$18.00	$27.85

MERC's proposed increased 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.

[328] Ex. 42 at 8 (G. Walters Rebuttal).

[329] Ex. 150 at 46-47 (V. Chavez Direct); Ex. 154 at 15-16 (J. Lindell Surrebuttal).

[330] Ex. 40 at 16 (G. Walters Direct).

[331] Ex. 40 at 12-13 (G. Walters Direct); Ex. 42 at 6-7 (G. Walters Rebuttal); Ex. 203 at 7-8, 12 (S. Peirce Direct).

[332] Ex. 40 at 16 (G. Walters Direct).

XVI. MERC HAS PROVIDED THE ADDITIONAL REQUESTED INFORMATION REGARDING JOINT SERVICE.

Joint Service allows an interruptible customer to designate a portion of its interruptible service as firm service. Under MERC's Joint Service Tariffs, Joint Service customers could have their service curtailed down to the level of usage designated as firm.[333] Joint service customers pay a per therm rate for daily firm capacity based on the amount of capacity designated as firm.[334]

A. MERC Has Responded to the Commission's Requests for Additional Information Regarding Joint Service.

In its November 27, 2013 Notice and Order for Hearing in this proceeding, the Commission requested that MERC provide supplemental testimony explaining how Joint Service customers are billed for service and how the joint rates in MERC's joint rate tariffs are applied. Specifically, the Commission asked for the following additional information:

- Examples of different billing scenarios that demonstrate how the joint rates are administered for sales and transportation joint customers compared to interruptible sales and transportation customers.

- 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.

- 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.[335]

333 Ex. 203 at 20 (S. Peirce Direct).

334 Ex. 203 at 20 (S. Peirce Direct).

335 Ex. 41 at 2-3 and Schedules (GJW-1 and GJW-2) (G. Walters Supplemental Direct).

On December 26, 2013, MERC witness Greg Walters filed Supplemental Direct Testimony responding to the Commission's above requests for additional information.[336]

B. MERC provided additional information regarding Joint Service during the May 13, 2014 evidentiary hearing.

During the May 13, 2014 evidentiary hearing, Commission staff asked Mr. Walters additional questions regarding Joint Service. Specifically, Commission staff asked for a summary of how Joint Service works and what it does for interruptible customers, whether joint customers are entitled to the same rights as MERC's general service firm customers, whether joint customers contribute their fair share or are being subsidized by other customers on MERC's system, and how curtailment impacts joint service. Mr. Walters provided detailed and thorough answers to each of Commission Staff's questions.[337]

C. The Department Has Determined That MERC's Firm Rate Customers Are Not Being Subsidized by MERC's Joint Service Customers.

The Department has determined that MERC's firm rate customers do not appear to be subsidizing the Company's joint service customers. Ms. Peirce explained that, based on Mr. Walters' Supplemental Testimony, joint service customers are charged the Daily Firm Capacity ("DFC") rate, plus the DFC Tariff Margin for their firm capacity.[338] Joint transportation customers are charged only the DFC Tariff Margin rate since they are securing their own pipeline capacity. Moreover, Mr. Walters explained that the revenues collected via the assessment of the current effective DFC Tariff Rate (without the margin rate factor) is credited back to all customers through the Purchased Gas Adjustment ("PGA"). Ms. Peirce testified that she was not concerned that MERC's joint customers are being subsidized by MERC's firm

[336] *See* Ex. 41 at 2-8 and Schedules (GJW-1 and GJW-2) (G. Walters Supplemental Direct).

[337] Evidentiary Hearing Transcript (May 13, 2014) at 116-131 (G. Walters).

[338] Ex. 203 at 20-21 (S. Peirce Direct).

customers because MERC is not purchasing additional capacity to serve the Company's joint rate customers.[339] Rather, MERC serves them from the Company's reserve margin and then credits back the revenues for the benefit of all firm customers. In the event that reserve margins are needed to serve firm customers, joint customers are held to their daily firm capacity and then curtailed. In the event of system constraints due to pipeline issues, MERC curtails all of the joint customer's gas, including the firm (though this would be a rare occurrence). Ms. Peirce recommended that the Commission accept MERC's explanation on administering its Joint Service.[340]

XVII. MERC'S CLASS COST OF SERVICE STUDY IS A USEFUL TOOL FOR THE PURPOSE OF SETTING RATES IN THIS PROCEEDING.

A. General Background

In accordance with Minn. R. 7825.4300(C), MERC prepared a Class Cost of Service Study ("CCOSS") in this matter, which was summarized in the testimony, exhibits, and workpapers of MERC witness Joylyn Hoffman Malueg.[341] 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.[342]

Minn. R. 7825.4300 recognizes the importance of cost factors in determining the appropriate rate structure and rate design:

> The following rate structure and design information as required by Part 7825.3800 shall be filed: . . . A cost of service study by customer class of service, by geographic area, or other categorization as deemed appropriate for the change in rates

[339] Ex. 203 at 20-21 (S. Peirce Direct).

[340] Ex. 203 at 21-22 (S. Peirce Direct).

[341] Ex. 29 (J. Hoffman Malueg Direct); Ex. 30 (J. Hoffman Malueg Rebuttal and Exhibits); Ex. 31 (errata to J. Hoffman Malueg Rebuttal; Ex. 6 (J. Hoffman Malueg Workpapers); Ex. 4 at Initial Filing Volume 3, Informational Requirement, Document 12.

[342] Ex. 29 at 5 (J. Hoffman Malueg Direct); Ex. 206 at 3 (S. Ouanes Direct).

> requested, showing revenues, costs, and profitability for each class of service, geographic area, or other appropriate category, identifying the procedures and underlying rationale for cost and revenue allocations. . . .[343]

The CCOSS prepared by MERC is a fully allocated, embedded cost of service study similar, but not identical, to that which was filed in MERC's 2010 rate case.[344] MERC's assignment of values to rate schedules was done, to the extent possible, as recommended by the American Gas Association ("AGA") in its Fourth Edition of Gas Rate Fundamentals (1987) and the National Association of Regulatory Commissioners ("NARUC") in their Gas Distribution Rate Design Manual (1989).[345] MERC's CCOSS was designed to associate costs with customers based on cost causation.[346] The results of the Company's CCOSS indicate an allocation of revenue deficiency by customer class, as set forth in the testimony and exhibits of Ms. Hoffman Malueg.[347]

The Department witness on this issue, Dr. Ouanes, recommended that the Commission accept MERC's CCOSS as a useful tool for the purpose of setting rates.[348] Additionally, Dr. Ouanes recommended that the Commission approve MERC's proposed 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.[349] Finally, the Department recommended that the Commission reject OAG witness Ron Nelson's suggestion that the

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343 MINN. R. 7825.4300(C).

344 Ex. 29 at 5-8 (J. Hoffman Malueg Direct); Ex. 30 at 44 (J. Hoffman Malueg Rebuttal).

345 Ex. 29 at 8 (J. Hoffman Malueg Direct).

346 Ex. 29 at 10 (J. Hoffman Malueg Direct).

347 Ex. 29 at 11 (J. Hoffman Malueg Direct).

348 Ex. 206 at 13 (S. Ouanes Direct); Ex. 208 at 13 (S. Ouanes Rebuttal); Ex. 209 at 4 (S. Ouanes Surrebuttal).

349 Ex. 209 at 4 (S. Ouanes Surrebuttal).

Commission order MERC to classify 30% of the Mains account as customer costs and 70% as capacity costs.[350]

B. MERC's Income Tax Allocation is Equivalent to an Allocation on the Basis of Taxable Income by Class that Fully and Only Reflects the Cost of Providing Service.

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.[351] The Department has verified that, under the circumstances of this case, MERC's proposed allocation 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.[352] MERC used the same approach in its 2010 rate case, Docket No. G007,011/GR-10-977, as it used in this case for the allocation of income taxes.[353] This approach, which allocates income taxes on the basis of taxable income by class that fully and only reflects the cost of providing service is the only reasonable approach for the allocation of income taxes and is consistent with Commission precedent. As recommended by the Department, the Commission should require that in future rate cases MERC must allocate income taxes by class on the basis of taxable income by class that fully and only reflects the CCOSS.[354] For purposes of this rate case, MERC and the Department determined, and the record evidence shows, that allocating income taxes on

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[350] Ex. 209 at 4-5 (S. Ouanes Surrebuttal).

[351] *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, FINDINGS OF FACT, CONCLUSIONS OF LAW, OR ORDER at 24 (June 29, 2009).

[352] Ex. 206 at 11-12 (S. Ouanes Direct).

[353] *See* Ex. 30 at 40 (J. Hoffman Malueg Rebuttal).

[354] Ex. 208 at 5-6 (S. Ouanes Rebuttal).

the basis of taxable income by class that fully and only reflects the cost of providing service is equivalent to using a rate base allocation methodology.[355]

1. It is inappropriate to allocate income taxes in the same manner as MERC calculates total income taxes for the Minnesota Jurisdiction.

The only party to object to MERC's proposed income tax allocation was the OAG. 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.[356] Mr. Lindell claims that allocating income taxes by class that fully and only reflects the CCOSS means that revenues are not considered to determine taxable income because the CCOSS only allocates costs.[357] Mr. Lindell's claim is inaccurate. As explained by MERC, and demonstrated by the record evidence, allocating income taxes on the basis of taxable income by class that fully and only reflects the CCOSS is mathematically equivalent to a proportion of rate base. Therefore, MERC allocates income taxes by using the rate base allocation methodology, which the Company believes is the most appropriate allocation methodology.[358] Moreover, Department witness Dr. Ouanes was able to determine that the tax rate across customer classes was the same as the tax rate applied to the Minnesota Jurisdiction,[359] undercutting Mr. Lindell's argument that MERC's proposed income tax allocation was not calculated and assigned to customer classes based on taxable income for each class reflective of revenues and expenses.[360]

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[355] Ex. 29 at 5 (J. Hoffman Malueg Direct); Ex. 4 at Schedules 1 and 9 (Information Requirements Document No. 12); Ex. 206 at 10-13 (S. Ouanes Direct); Ex. 208 at 2-3, 5-6 (Ouanes Rebuttal).

[356] Ex. 151 at 28 (J. Lindell Direct); Ex. 154 at 14-15 (J. Lindell Surrebuttal).

[357] Ex. 151 at 26-28 (J. Lindell Direct); Ex. 153 at 6-9 (J. Lindell Rebuttal); Ex. 154 at 12-15 (J. Lindell Surrebuttal).

[358] Ex. 30 at 36-41 (J. Hoffman Malueg Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 67 (J. Hoffman Malueg).

[359] Ex. 208 at 4 (S. Ouanes Rebuttal).

[360] Ex. 151 at 26-28 (J. Lindell Direct); Ex. 153 at 6-9 (J. Lindell Rebuttal); Ex. 154 at 12-15 (J. Lindell Surrebuttal).

2. MERC's allocation of income taxes to customer classes within the CCOSS is consistent with past Commission decisions.

The OAG argues that MERC's allocation of income taxes to customer classes within the CCOSS is inconsistent with past Commission decisions.[361] Contrary to the OAG's argument, and as summarized in the ALJ's recommendations in MERC's last rate case, the Department and MERC agreed 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. This recommendation was incorporated into the final rate case order, 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 CCOSSs does not equate to a Commission finding that MERC be required to treat income taxes in a specified way in all future CCOSS's. Rather, as reflected in the May 22, 2012 and May 24, 2012 transcripts memorializing the Commission's deliberations, the Commission concluded that it was unnecessary to take a position on this issue.[362] Thus, because MERC and the Department were able to determine that MERC's rate base allocation methodology was equivalent to allocating income taxes by class on the basis of taxable income that fully and only reflects the CCOSS, MERC has demonstrated that it did comply with the intent of prior Commission decisions and that MERC's proposed allocation of income taxes by class is reasonable.[363]

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[361] Ex. 151 at 26-28 (J. Lindell Direct); Ex. 153 at 6-9 (J. Lindell Rebuttal); Ex. 154 at 14-15 (J. Lindell Surrebuttal).

[362] Ex. 30 at 40-41 (J. Hoffman Malueg Rebuttal).

[363] Ex. 29 at 3-4 (J. Hoffman Malueg Direct); Ex. 30 at 25, 40-43 (J. Hoffman Malueg Rebuttal).

C. As Evidenced by MERC's Zero-Intercept Study, MERC's Distribution Mains Are Properly Classified at 68.3 Percent Customer Cost and 31.7 Percent Demand Cost.

Calculating cost of service involves a degree of subjectivity and, as a result, there is no one singularly correct CCOSS for a utility.[364] Even the OAG acknowledged that the CCOSS is a highly subjective tool.[365] Based on MERC's 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.[366] The OAG argued that MERC's zero-intercept analysis violated multiple econometric assumptions that resulted in MERC incorrectly estimating its Mains account distributions and recommended a 30 percent customer classification and 70 percent demand classification for the Mains account.[367] However, at the Department's request, MERC conducted additional analysis to corroborate the Company's initial distribution main classification data. The additional analysis did corroborate MERC's initial findings. This resulted in the Department accepting MERC's proposed classification of distribution mains and rejecting the OAG's proposed classification of distribution mains.[368]

1. MERC does not need to account for more variables in its zero-intercept study.

The OAG incorrectly argues that MERC needs to collect data on additional variables to improve the Company's zero-intercept analysis.[369] As detailed in the Rebuttal Testimony of Ms. Hoffman Malueg, many of the variables recommended by the OAG are already included in the Company's zero-intercept analysis. Any missing variables were omitted, not due to

364 Evidentiary Hearing Transcript (May 13, 2014) at 70 (J. Hoffman Malueg).

365 Ex. 155 at 5 (R. Nelson Direct); Evidentiary Hearing Transcript (May 13, 2014) at 175 (R. Nelson).

366 *See generally* Ex. 29 (J. Hoffman Malueg Direct); *see also* Ex. 30 at 4-25 (J. Hoffman Malueg Rebuttal).

367 Ex. 155 at 5-40 (R. Nelson Direct).

368 Ex. 208 at 11-12 (Ouanes Rebuttal).

369 Ex. 155 at 34-35 (R. Nelson Direct).

unwillingness to collect the data, but rather due to limited data availability.[370] MERC has never stated that it does not want to collect more data than it currently does.[371] It is important that the Commission understand, however, that although MERC may be able to retrieve additional distribution main information, such collection would be no small undertaking. Significant financial and personnel resources would be required for the Company to gather this information from hard-copy, paper documentation and, even then, the paper documentation likely would not provide a complete picture of all of MERC's distribution installations.[372] As acknowledged by OAG witness Mr. Nelson, 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.[373] It is for this reason that MERC performed its zero-intercept study based on data that is available, complete, and pertinent to the analysis in the current rate case.[374]

2. Requiring MERC to maintain project level data is inefficient, unsupportable and cannot be cost justified.

The OAG's recommendation that MERC maintain project level data is wholly unsupportable. The OAG improperly seeks to hold MERC to a higher standard than its Minnesota utility counterparts by advocating that MERC maintain distribution main data at the project level.[375] Despite Mr. Nelson's statement that project level data is collected by other Minnesota utilities, Mr. Nelson only identified one Minnesota utility, CenterPoint Energy, that

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[370] Ex. 30 at 4-9 (J. Hoffman Malueg Rebuttal).

[371] Ex. 155 at 34-35, 38 (R. Nelson Direct).

[372] Ex. 30 at 9 (J. Hoffman Malueg Rebuttal).

[373] Ex. 155 at 15 (R. Nelson Direct); Evidentiary Hearing Transcript (May 13, 2014) at 161 ("Those are just variables that I think that possibly go in the model. I'm not trying to state that every one of those variables needs to be in the model.").

[374] Ex. 30 at 9 (J. Hoffman Malueg Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 68-69 (J. Hoffman Malueg); Exs. 32-35 IR Nos. 700, 702, 704 and 711.

[375] Ex. 155 at 16-17, 38 (R. Nelson Direct); Ex. 158 at 6-7 (R. Nelson Surrebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 156-57 (R. Nelson).

collects the type of data Mr. Nelson considers to be project level data.[376] MERC has not been required to maintain this level of detailed information in the past. Nor, to MERC's knowledge, is collection of this data required of other Minnesota utilities, a point which Mr. Nelson concedes.[377]

The OAG's recommendation that MERC maintain project level data also fails for practical reasons. First, to gather 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 second 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.[378]

3. 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.[379] Ms. Hoffman Malueg testified that 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 MERC's

[376] Ex. 155 at 17 & n.10 (R. Nelson Direct).

[377] Ex. 30 at 11, 13 (J. Hoffman Malueg Rebuttal); Ex. 158 at 6 (R. Nelson Surrebuttal).

[378] Ex. 30 at 10-12 (J. Hoffman Malueg Rebuttal).

[379] Ex. 155 at 34 (R. Nelson Direct).

distribution mains as an entire system, separating the distribution mains between the classifications of customer and demand.[380]

MERC's approach is supported by both the NARUC Electric Manual and the NARUC Gas Distribution Rate Design manual. The NARUC Electric Manual clearly states the data one would need to perform a zero-intercept analysis on various electric assets and each time the NARUC states that average installed book cost should be utilized. As gas utilities commonly consult the NARUC Electric Manual for guidance on cost allocation, 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.[381] Mr. Nelson's own Direct Testimony in CenterPoint Docket No. 13-316 implies acknowledgement of this concept, as page 11 of 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.[382]

4. MERC's zero-intercept analysis is the proper tool to determine the classification of MERC's distribution mains.

The OAG relies on what it calls a "superior" zero-intercept study in this rate case proceeding and zero-intercept analyses completed in other jurisdictions to reach its conclusion that 30 percent of MERC's distribution main costs should be allocated to customers, and 70 percent should be allocated to demand.[383] The OAG's conclusion is misguided.

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[380] Ex. 30 at 17-19 (J. Hoffman Malueg Rebuttal).

[381] Ex. 30 at 18-19 (J. Hoffman Malueg Rebuttal).

[382] Ex. 30 at 17-19 (J. Hoffman Malueg Rebuttal).

[383] Ex. 155 at 36-40 (R. Nelson Direct); Ex. 158 at 10-12, 17-18 (R. Nelson Surrebuttal).

First, as previously discussed, it is imperative to utilize average unit costs in the zero-intercept analysis. Thus, Mr. Nelson's recommendation that MERC not average or aggregate demonstrates that MERC's zero-intercept analysis is the more appropriate analysis for MERC's CCOSS.[384] Second, it is inappropriate to conduct the zero-intercept analysis, or a minimum size analysis, without considering MERC's current minimum installation practices. Yet, the OAG appears to give no consideration whatsoever 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.[385] Third, the negative values in Exhibit REN-13 of Mr. Nelson's Direct Testimony clearly 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. In addition, 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 in fact are, just as much a minimum installation requirement as plastic. As previously discussed, an inaccurate cost causation picture of MERC's current customers can result in improper customer rates.[386]

The zero-intercept analyses conducted in other jurisdictions are not a sound basis for Mr. Nelson's recommended change to MERC's distribution main classification percentages. MERC has its own distinct service territory comprised of its own unique customers and their

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[384] Ex. 30 at 20-21 (J. Hoffman Malueg Rebuttal).

[385] Ex. 30 at 20-21 (J. Hoffman Malueg Rebuttal).

[386] Ex. 30 at 19-23 and Schedule (JCHM-4) (J. Hoffman Malueg Rebuttal).

associated demands, as well as their own unique geographic terrain and distribution system requirements. In addition, other jurisdictions may have different state regulations or may utilize different processes or steps than MERC when conducting their minimum system studies. Thus, absent assurances of an apples-to-apples comparison, which Mr. Nelson was unable to provide, to rely on such analyses to determine MERC's rates would be unsupportable and unwise.[387]

Perhaps the strongest indication that MERC's CCOSS is the proper tool to determine the allocation of MERC's distribution mains are the results of a third minimum size study conducted by MERC, and a minimum size analysis MERC performed at the request of the Department. The first two minimum size studies conducted by MERC produced similar results and corroborated MERC's 68.3 percent customer and 31.7 percent demand distribution main classifications. The third study, which most closely approximates Mr. Nelson's "superior" zero-intercept analysis, considered information from a minimum size study performed by MERC on the Company's distribution mains that did not consider MERC's minimum installation standards. The study illustrated the extreme and improper results that can occur when utility-specific minimum installation standards are not considered. Thus, the third study is inappropriate to determine mains distribution in the current rate case.[388]

At the request of the Department, MERC performed an additional minimum size analysis. The results of that study showed that at least 73 percent of the distribution mains would be classified as customer costs under the minimum size method. Based on the results of MERC's

[387] Ex. 30 at 23-25 (J. Hoffman Malueg Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 159-161 (R. Nelson).

[388] Ex. 30 at 3, 14-17 and Schedules (JCHM-1, JCHM-3 and JCHM-4) (J. Hoffman Malueg Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 83-84 (J. Hoffman Malueg).

analysis, the Department recommended no change in MERC's proposed classification of distribution mains.[389]

D. MERC's Allocation of FERC Account 903 Gives Proper Consideration to the Complexity of Accounts and Meters Within Each Customer Class.

The OAG advocates that MERC allocate Account 903: Customer Records & Collection Expense using a weighted customer allocator that is weighted by the average cost per customer for meters in each respective rate schedule.[390] The costs in Account 903 are not costs associated with meters. Rather, 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.[391]

Contrary to the assertions of the OAG,[392] the record evidence supports that MERC properly allocated its transportation costs to, and considered the complexity of, its customers. 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

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[389] Ex. 208 at 11-12 and Schedule (SO-R-4) (S. Ouanes Rebuttal).

[390] Contrary to Mr. Nelson's statements at the May 13, 2014 Evidentiary Hearing, he did recommend that MERC use the weighted allocator from FERC Account 381 – Meters - to allocate the Company's FERC Account 903 costs. *Compare* Ex. 155 at 42 (R. Nelson Direct) ("The NARUC Manual allocates FERC accounts 902 and 903 on the basis of meter count, which is the weighted customer allocator created for FERC account 381. For this case, I recommend that the Commission Order MERC to follow the NARUC Manual's recommended allocation method. FERC accounts 902 and 903 should be allocated using the same weighted customer allocator that is used for FERC account 381."); Ex. 158 at 20 (R. Nelson Surrebuttal) ("I recommend that MERC be ordered to use a customer weighed allocation method for FERC account 903. I note that the NARUC gas manual uses the same allocator for this account as FERC account 381."); *with* Hearing Transcript at 154-155 ("I do not, as Ms. Hoffman Malueg stated in her opening comments, suggest that [FERC account 903] must be allocated using the meters allocator.").

[391] Ex. 30 at 32-33 (J. Hoffman Malueg Rebuttal).

[392] Ex. 155 at 3, 41-42 (R. Nelson Direct); Ex. 158 at 19-20 (R. Nelson Surrebuttal); Hearing Transcript at 154-55 (R. Nelson).

removing the costs from administering MERC's transportation program from Account 903. The costs that remain in Account 903 are primarily related to MERC's employment of its third party external service provider, Vertex.[393] There are no significant costs differences amongst MERC's customer classes for the Vertex costs and MERC allocates the costs to MERC's CCOSS based on customer counts. Mr. Nelson'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.[394] Moreover, Mr. Nelson's argument that using a weighted customer allocator for Account 903 is recommended by NARUC in the NARUC gas manual is inapplicable in this rate case. While 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.[395]

XVIII. MERC'S PROPOSED TREATMENT OF UNCOLLECTED CIP EXPENSE IS PROPER.

MERC recently discovered that one of its taconite customers, Northshore Mining ("Northshore") was erroneously treated as CIP-exempt dating back to the days of MERC's predecessor, Aquila's, gas operations. Upon discovery of the error, MERC notified Northshore and Northshore applied for a CIP exemption. Northshore is a SLV transportation customer and a very serious bypass threat. MERC prepared its CIP-year test schedules assuming that

393 Vertex performs customer service and billing functions for all of MERC's customers.

394 Ex. 30 at 33-35 (J. Hoffman Malueg Rebuttal); Hearing Transcript Vol. 1 at 69-71 (J. Hoffman Malueg).

395 Ex. 30 at 35 (J. Hoffman Malueg Rebuttal); Hearing Transcript Vol. 1 at 70-71 (J. Hoffman Malueg).

Northshore would be granted a CIP exemption.[396] Northshore was granted a CIP exemption effective January 1, 2014.[397]

The Department recommended that MERC credit the CIP tracker for uncollected amounts of CCRA and CCRC from July 2006 through December 2013, before Northshore's CIP exemption was effective on January 1, 2014, and report the unrecovered CIP information in the Company's final rates compliance filing.[398] The Department also recommended that the Commission assess MERC a one-time carrying charge using MERC's approved overall rate of return in effect during the period of under collection (July 2006 through December 2013).[399] In addition to proactively determining to absorb the under-recovery associated with the Northshore uncollected amounts, MERC agreed with these Department recommendations.[400]

MERC takes the assessment of CIP very seriously. It is for this reason that MERC is agreeing to write off well over a million dollars related to Northshore. It is also why MERC continually strives to clearly identify its CIP exempt customers in its billing system and is reviewing customers that are similarly situated to Northshore in an effort to prevent this type of situation from occurring again.[401] Given MERC's willingness to absorb the under-recovery related to Northshore, credit the CIP tracker for the uncollected amounts and continue to improve the Company's billing system to properly identify CIP exempt customers, the Commission should approve MERC's approach to uncollected CIP expense in this rate case.

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396 Ex. 19 at 44 (S. DeMerritt Direct); Ex. 21 at 3-4 (S. DeMerritt Supplemental Direct); Ex. 22 at Schedules (SSD-1 and SSD-2).

397 Ex. 217 at 19 (M. St. Pierre Direct).

398 Ex. 217 at 20-21 (M. St. Pierre Direct); Ex. 219 at 19-20 (M. St. Pierre Surrebuttal).

399 Ex. 217 at 20 (M. St. Pierre Direct); Ex. 219 at 19-20 (M. St. Pierre Surrebuttal).

400 Ex. 24 at 7-8, 13-14 (S. DeMerritt Rebuttal); Hearing Transcript at 35-37 (S. DeMerritt).

401 Evidentiary Hearing Transcript (May 13, 2014) at 35-37 (S. DeMerritt).

XIX. CONCLUSION

Based upon the evidence presented in the record and the arguments made herein, MERC respectfully requests that (i) an increase of $12,159,454 in Company revenues be granted; (ii) MERC's proposed rate design be adopted; and (iii) MERC's proposed treatment of uncollected CIP expense related to Northshore Mining be approved.

Dated this 24th day of June, 2014.

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