BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Betsy Wergin	Commissioner

In the Matter of a Petition by Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota

ISSUE DATE: October 28, 2014

DOCKET NO. G-011/GR-13-617

FINDINGS OF FACT,
CONCLUSIONS, AND ORDER

Contents

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PROCEDURAL HISTORY

I. Initial Filings and Orders

On September 30, 2013, Minnesota Energy Resources Corporation (MERC or the Company) filed this general rate case seeking an annual rate increase of some $14,187,597, or approximately 5.52%. The filing included a proposed interim rate schedule.

On the same date, the Company filed a petition to establish a new base cost of gas, to be implemented at the same time as new interim rates. That petition was granted by order dated November 27, 2013, subject to the requirement that the Company update the commodity cost of gas at least once during this rate-case proceeding.[1]

Also on November 27, 2013, the Commission issued three orders in this case:

- an order finding the rate-case filing substantially complete, suspending the proposed final rates, and extending the procedural schedule and suspension period under Minn. Stat. § 216B.16, subd. 2 (f);
- a notice and order for hearing referring the case to the Office of Administrative Hearings for contested case proceedings; and
- an order setting interim rates for the period during which the rate case was being resolved.

II. The Parties and Their Representatives

The following parties appeared in this case:

[1] *In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a New Base Gas Cost for Interim Rates*, Docket No. G-011/MR-13-732, Order Setting New Base Cost of Gas (November 27, 2013).

- Minnesota Energy Resources Corporation (MERC or the Company), represented by Michael J. Ahern, Kristin M. Stastny, and Kristin K. Berkland, Dorsey & Whitney LLP.

- Minnesota Department of Commerce, Division of Energy Resources (the Department), represented by Julia E. Anderson, Linda S. Jensen, and Peter Madsen, Assistant Attorneys General.

- Antitrust and Utilities Division of the Office of the Attorney General (OAG), represented by Ian M. Dobson and Ryan P. Barlow, Assistant Attorneys General.

- Hibbing Taconite Company, ArcelorMittal USA's Minorca Mine, Northshore Mining Company, United Taconite, the Minntac and Keewatin Mines of United States Steel Corporation, and USG Interiors, Inc., appearing jointly as "Super Large Gas Intervenors" and represented by Andrew P. Moratzka and Chad T. Marriott, Stoel Rives LLP.

- Constellation New Energy—Gas Division, LLC, represented by Richard J. Savelkoul, Martin Squires, P.A.

Constellation New Energy did not participate in the case beyond the filing of direct testimony. The Super Large Gas Intervenors did not participate beyond intervening and filing a June 24, 2014 letter stating the group had no issues to raise at that point and reserved the right to respond to any new issues raised in briefing.

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Eric L. Lipman to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings. The ALJ held an evidentiary hearing in Saint Paul on May 13, 2014. After the hearing the parties filed initial briefs, reply briefs, and proposed findings of fact.

The ALJ also held three public hearings in the case, on the dates and at the locations set forth below:

- Rochester—March 12, 2014
- Rosemount—March 12, 2014
- Cloquet—March 13, 2013

IV. Public Comments

The Administrative Law Judge held three public hearings; twelve members of the public attended and ten spoke. Representatives of MERC, the Department, the Office of the Attorney General, and the Commission also attended, to answer questions and receive public input. Ninety-five members of the public submitted written comments.

Nearly all commenting members of the public were opposed to the rate increase proposed by the Company. The objections raised most frequently were that the increase would cause hardship for low-income households, especially senior citizens relying on Social Security benefits; that the Company was not controlling costs sufficiently; that falling natural gas prices and the recent increase in domestic production should lead to lower bills; and that the Company should scale back its profit expectations in these challenging economic times.

V. Proceedings Before the Commission

On August 13, 2014, the Administrative Law Judge filed his Findings of Fact, Summary of Public Testimony, Conclusions of Law and Recommendation (the ALJ's Report). MERC, the Department, and the OAG filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700.

On September 18 and 24, 2014, the Commission heard oral argument from and asked questions of the parties. On September 24, 2014, the record closed under Minn. Stat. § 14.61, subd. 2.

Having examined the entire record in this case, and having heard the arguments of the parties, the Commission makes the following findings, conclusions, and order.

FINDINGS AND CONCLUSIONS

I. The Ratemaking Process

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.[2] The Minnesota Supreme Court has described the Commission's statutory mandate for determining whether proposed rates are just and reasonable as "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers," citing Minn. Stat. § 216B.16, subd. 6.[3] That statute is set forth in pertinent part below:

> The commission, in the exercise of its powers 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 the 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.

B. The Commission's Role

While the Public Utilities Act provides baseline guidance on the ratemaking treatment of different kinds of utility costs, it generally makes only threshold determinations on rate recoverability, leaving to the Commission the tasks of determining (a) the accuracy and validity of claimed costs;

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

[3] *In the Matter of the Request of Interstate Power Company for Authority to Change its Rates for Gas Service in Minnesota*, 574 N.W.2d 408, 411 (Minn. 1998).

(b) the prudence and reasonableness of claimed costs; and (c) the compatibility of claimed costs with the public interest.

In ratemaking, therefore, the Commission must decide a wide range of issues, ranging from the accuracy of the financial information provided by the utility, to the prudence and reasonableness of the underlying transactions and business judgments, to the proper distribution of the final revenue requirement among different customer classes.

These diverse issues require different analytical approaches, involve different burdens of proof, and require the Commission to exercise different functions and powers. In ratemaking the Commission acts in both its quasi-judicial and quasi-legislative capacities: As a quasi-judicial body it engages in traditional fact-finding, and as a quasi-legislative body it applies its institutional expertise and judgment to resolve issues that turn on both factual findings and policy judgments. As the Supreme Court has explained:

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[4]

C. The Burden of Proof

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable.[5] Any doubt as to reasonableness is to be resolved in favor of the consumer.[6]

On purely factual issues, the Commission acts in its quasi-judicial capacity and weighs evidence in the same manner as a district court, requiring that facts be proved by a preponderance of the evidence. On issues involving policy judgments, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.

Utilities seeking rate changes must therefore prove not only that the facts they present are accurate, but that the costs they seek to recover are rate-recoverable, that the rate recovery mechanisms they

[4] *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722–23 (Minn. 1987) (citation omitted).

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

propose are permissible, and that the rate design they advocate is equitable, under the "just and reasonable" standard set by statute. As the Court of Appeals explained, quoting the Supreme Court:

> A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. Minn. Stat. § 216B.16, subd. 4 (1986). "Preponderance of the evidence" is defined for ratemaking proceedings as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[7]

II. Summary of the Issues

In its Notice and Order for Hearing, the Commission directed the Company to address four nonstandard rate-case issues and to file supplemental testimony and information on five other issues specific to this case. Those issues are addressed below.

Some initially contested issues were largely resolved by the time of oral argument. The Administrative Law Judge found that the resolutions reached by the parties were reasonable and supported by record evidence; he recommended accepting them. The Commission concurs.

Other issues remained contested. The following issues were either contested or otherwise require discussion.

Financial Issues

- ***Discount Rate for Pension, Post-Retirement Medical, and Post-Retirement Life-Insurance Plans—***What is the appropriate discount rate, the interest rate used to adjust anticipated future benefits to present dollars, for the Company's pension, post-retirement medical, and post-retirement life-insurance plans?

- ***Property taxes—***Is the Company's proposed property tax expense reasonable, prudent, and otherwise eligible for rate recovery?

- ***Bad-Debt Expense—***Has the Company demonstrated that its proposed bad-debt expense is set at a level that is reasonable and prudent?

- ***Inflation Factor—***Has the Company demonstrated that inflation projections built into test-year expenses are reasonable and prudent?

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[7] *In the Matter of the Petition of Minnesota Power & Light Company, d.b.a. Minnesota Power, for Authority to Change its Schedule of Rates for Electric Utility Service Within the State of Minnesota*, 435 N.W.2d 550, 554 (Minn. App. 1989) (citation omitted).

- ***Customer-Relations Costs—***Has the Company demonstrated the reasonableness and prudence of its customer-relations expense as it incurs costs both for its existing customer-relations system and for its transition to a new system?

- ***Deferred Tax Asset for Net Operating Loss Carryforward—***Has the Company demonstrated the reasonableness and prudence of including in rate base an adjustment representing a Deferred Tax Asset for a Net Operating Loss carryforward?

- ***Benefit Trust Funds as Regulatory Assets/Liabilities—***Has the Company demonstrated the reasonableness and prudence of including in rate base company-supplied benefit trust funds?

- ***Travel and Entertainment Expense—***Has the Company demonstrated the reasonableness and prudence, and demonstrated rate recoverability under the rate-case statute, of claimed travel and entertainment expense?

Cost of Capital Issues

- ***Return on Equity—***What is a fair and reasonable rate of return on equity for this company, on this record, at this time?

Class Cost of Service Study (CCOSS) Issues

- ***Adequacy of the CCOSS—***Is the Company's CCOSS adequate for purposes of this rate case?

- ***CCOSS Treatment of Income Tax—***Does the Company's CCOSS properly allocate income taxes among the customer classes?

- ***CCOSS Treatment of Distribution-Main Costs—***Is the Company's allocation of the costs of its distribution mains between customer costs and capacity costs the most reasonable allocation in the record?

- ***CCOSS Treatment of Customer Records and Collection Expense, FERC Account 903—***Is the Company's interclass allocation of these expenses by number of customers (excepting transportation customers) the most reasonable allocation method in the record?

Rate Design Issues

- ***Interclass Revenue Apportionment—***Should the interclass revenue apportionment method approved in this case move the revenue responsibilities of customer classes closer to cost?

- ***Residential and Small Commercial and Industrial Customer Charges—***Should the customer charges for the residential and the small commercial and industrial classes be adjusted to more closely approximate the fixed costs of service, and if so, to what levels?

These issues are examined individually below, with issues on which the Commission declines to accept the ALJ's recommendation discussed in greater detail.

III. Specific Issues Identified in Notice and Order for Hearing

In its Notice and Order for Hearing, the Commission singled out several issues that appeared to require further development and directed the Company to file supplemental testimony on other issues specific to this case.

The Company addressed the issues identified and filed the supplemental testimony required; the parties and the ALJ examined them in the course of this proceeding. These issues and filings are treated below.

1) **Test-year Forecast for Late Payment Revenues and Other Revenues—**The Commission requested supplementary filings to support and explain the test-year forecast for Late Payment Revenues and Other Revenues.

Because the Company's initial filing included a largely unexplained decrease in Other Revenues, the Commission's Notice and Order for Hearing included a request "that the parties address MERC's test year forecast for late payment and other revenues in their prefiled direct testimony."[8]

The Department examined the Company's test-year calculations, found that the test-year amount was based on annualizing seven months of 2012 actual data, and noted significant past fluctuations in this revenue category. The agency therefore recommended using the average of actual annual revenues for the latest available four-year period, 2010 to 2013, to reduce the impact of revenue volatility. This adjustment would result in a $51,493 test-year revenue increase.

The Company concurred in this recommendation, and the Administrative Law Judge found it appropriate and proper in this rate case.[9] The Commission concurs and will adopt that upward test-year revenue adjustment. The Commission will also require MERC to provide direct testimony in future rate cases explaining all large differences between base-year and test-year rate base, other income, and expense data.

2) **Test-year Regulatory Assets and Liabilities—**The Commission requested supplementary filings to support and explain the Company's claimed test-year Regulatory Assets and Liabilities.

The Company made the requested filings; it claimed some $19,642,806 in net regulatory assets, of which $18,837,482 were employee benefit funds, chiefly pension funds. The Department and the Company agreed on the treatment of all non-employee-benefit amounts, and the Administrative Law Judge concurred in these agreements.

The Company's treatment of employee benefit trust funds as regulatory assets was fully addressed in the course of this rate case and is discussed below with the other contested issues.

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[8] Notice and Order for Hearing, this docket (November 27, 2013) at 2.

[9] ALJ's Report ¶ 516.

3) **Joint Rate Service—**The Commission requested evidentiary development on the Company's joint rate service, including its administration, its reasonableness in respect to both gas and non-gas costs and rates, and whether its tariff required clarification.

MERC offers its interruptible sales and interruptible transportation customers the option of designating a portion of their service as firm service. When interruptible service would otherwise be curtailed, this portion of their service continues, subject to MERC having enough capacity on its system to meet the needs of non-joint-rate firm customers. Joint Rate Service customers pay a per-therm rate for daily firm capacity based on the amount of service they have designated as firm.

The Commission requested supplemental testimony as set forth below:

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

- 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.

The Company filed supplemental testimony addressing the issues listed above. The Department examined the Company's testimony and exhibits, concluded that Joint Rate Service customers were not being subsidized by firm service customers, and recommended that the Commission accept the Company's supplemental testimony on this issue. The Administrative Law Judge noted these conclusions and recommendations without making a specific recommendation of his own.

While the supplemental testimony and analysis in the record provide a great deal of clarifying detail, the Commission finds that Joint Rate Service merits further review to ensure that its rate structure does not incorporate subsidies from firm service customers. Commission concerns fall into four categories:

- ***Curtailment Hierarchy—***MERC's tariffs do not appear to create a separate position in the Company's curtailment hierarchy for the portion of Joint Rate Service loads designated as firm, despite other tariff provisions providing that these loads will be curtailed before those of firm customers.

- ***Joint Service Premium*—**It is unclear that the demand-based premium applied to load designated as firm adequately reflects interstate pipeline demand charges and hedging demand costs.

- ***Cost of Gas*—**It is unclear that the cost of gas applied through the Purchased Gas Adjustment (PGA) to load designated as firm adequately reflects the cost of gas, given the interstate pipeline demand charges and hedging demand costs normally passed through the PGA.

- ***Distribution Charge*—**It is unclear that the interruptible distribution charge remains the appropriate distribution charge for Joint Rate Service customers.

The Commission will therefore direct the Company to work with the Department to address and resolve these concerns, and to make a compliance filing reporting on these efforts within 90 days of the date of this order.

4) **Conservation Cost Recovery Charge—**the Commission requested supplemental testimony, as follows, on how MERC calculated its Conservation Cost Recovery Charge and Conservation Cost Recovery Adjustment, the two mechanisms by which it recovers the costs of its Conservation Improvement Program (CIP):

    - Supplemental direct testimony reflecting the calculation of the applicable Conservation Cost Recovery Charge (CCRC) and Conservation Cost Recovery Adjustment (CCRA) charges since July 2006.

    - The applicable Northshore Mining Company volumes, CCRC and CCRA rates, and the CCRC and CCRA amounts, by month, for the stated period of time, July 2006 through December 31, 2013.

The Company filed supplemental testimony that all parties agreed met the requirements of the Notice and Order for Hearing; the Administrative Law Judge concurred. Substantive CIP issues, which were long contested, thoroughly examined, and ultimately resolved between the parties, are discussed below (see **CIP Expenses Generally**, below).

5) **Vertex Billing Audit—**The Commission requested additional information from all parties on the adequacy of the Vertex billing audit in regard to finding CIP-related and other billing errors.

During the Company's last rate case it discovered and reported that it had been improperly billing at CIP-exempt rates three large customers who were not CIP-exempt.[10] In response to parties' concerns, the Company retained an accounting firm to conduct an audit of its billing system, Vertex.

[10] Under Minn. Stat. § 216B.241, subd. 1a, certain large customers may petition the Commissioner of Commerce for exemption from the portion of tariffed rates attributable to the costs and investments required of utilities under the Conservation Improvement Program (CIP). Among other requirements, these customers must demonstrate that they have independently taken reasonable measures to identify, evaluate, and implement energy conservation and efficiency improvements and are subject to competitive or economic pressures.

That audit was not complete by the end of the last rate case, but the Company made follow-up filings under the direction of the Commission. Those filings generally indicated compliance with normal accounting procedures and revealed no major lapses. In this rate case, too, however, the Company discovered and reported that it had been billing as CIP-exempt one nonexempt customer, renewing concerns about the reliability of the Vertex audit and the Company's proficiency in administering the statutory CIP-exemption program.

While the Company filed supplemental testimony that all parties agreed met the filing requirements of the Notice and Order for Hearing—and the Commission concurs—additional follow-up on this issue is required.

The Commission will therefore require MERC to review its CIP billing process, make a compliance filing in this docket reporting its findings from that review, and make annual compliance filings with future CIP tracker filings documenting that its CIP-exempt customers have been properly identified and are being properly billed.

6) **CIP Expenses Generally**—The Commission requested additional information regarding the Company's tracking and handling of CIP expenses in the development of the test-year operating expenses.

CIP expenses are an integral part of the cost of service, and increases in CIP costs constitute some $3,800,000 of the Company's requested rate increase. The CIP program encompasses most of the State's natural-gas conservation and energy-efficiency initiatives, from energy audits and appliance rebates to energy-efficient construction guidelines and manufacturing process improvements.

CIP costs are recovered differently than most other test-year costs. Most utility costs are built into rates using the test-year concept—they are built in at amounts determined to be reasonable and prudent by examining all utility costs over the course of a representative one-year period, the test year. While actual costs going forward will differ from test-year costs to some extent in every category, the careful scrutiny these costs receive during a rate case is expected to ensure that these cost differences will be essentially symmetrical, favoring neither the Company nor ratepayers in the aggregate.

As a matter of public policy, the Legislature has determined that utilities should generally be permitted to recover their CIP costs dollar for dollar, instead of relying on test-year rate recovery.[11] CIP costs are therefore recovered in two ways: through the Conservation Cost Recovery Charge (CCRC), a component of base rates that recovers baseline, test-year CIP costs, and through the Conservation Cost Recovery Adjustment (CCRA), an automatic rate-adjustment mechanism that trues up differences between actual CIP costs and those recorded in the CCRC.

In this case, CIP cost-recovery issues became unusually complicated due to several factors, including the Company's underreporting of CIP costs in its initial filing, the accounting challenges created by the Company's billing of certain non-CIP-exempt customers at CIP-exempt rates, and the Department's efforts to refine CIP accounting procedures to more closely match CIP costs and CIP revenues in order to increase transparency and administrative efficiency.

[11] Minn. Stat. § 216B.241, subd. 2b.

The Company and the Department were the parties who addressed CIP issues, and they continued their discussions throughout the case, ultimately reaching agreement on the final day of oral argument. They had long agreed on basic facts, such as test-year CIP costs of $9,396,422, and ultimately agreed on operational details as well.

They concluded that the Company's current CIP cost-recovery procedures—recovering test-year costs through the CCRC and truing up differences between those costs and actual costs through the CCRA—were the most workable procedures examined in the record. They noted that they had worked through the thorniest accounting issues in the course of this case and expected less complexity in the future, both because the erroneous-exemption billing issues had been resolved and because the Company had committed to adapting its CIP reporting format and content to meet the regulatory needs of the Department.

In brief, the points on which the parties reached agreement are set forth below.

- *Revenues from Northshore Mining, Improperly Billed as CIP-Exempt*—MERC will credit its CIP tracker account for CIP revenues not collected from this customer and will include carrying charges.
- *CCRC Calculation*—MERC will calculate its CCRC based on the terms of this order.
- *Carrying Charges*—MERC will apply carrying charges to its CIP tracker account at the overall rate of return approved in this order. (The carrying-charge issue will also be examined in the Company's pending CIP filing, the conventional vehicle for setting carrying charges.)
- *Revenue Deficiency Calculation*—MERC will collect test-year CIP costs through its CCRC, set at $0.02448, with $0.00000 being added to its CCRA at implementation of final rates. MERC will continue its current CCRC calculation methodology by including the CCRC factor in its base distribution rate and maintaining its CCRA in its current format.
- *Future Pre-Rate-Case Meetings*—MERC will meet with Department and Commission staff on CIP issues prior to each future rate-case filing.
- *Interim-Rate-Period CCRC Factor*—The Commission will accept the ALJ's finding that the CCRC calculation methodology is reasonable, but the Company will update the factor to reflect CIP expenses of $9,396,422 and correct CIP-applicable volumes to the level recommended by the Department.
- *Compliance Filing*—MERC will report the calculation of its CCRC based on the terms of this order in its post-rate-case compliance filing.
- *Future Interim Rates CCRC Factors*—In future rate cases, MERC will change its CCRC at the beginning of the interim-rate period and again at final rates.
- *Over- or Under-collected CIP Costs During Interim-Rate Period*—MERC will debit or credit the CIP tracker account in the event that it over- or under-recovered CIP costs during the interim-rate period.
- *Future Presentation of CCRC and CCRA*—MERC will continue using its existing CCRC calculation methodology, including the CCRC in base rates, and will maintain its CCRA in its current format.

The Commission concurs with the parties that these issues have been properly resolved. The Commission therefore declines to adopt the Administrative Law Judge's findings and recommendations in paragraphs 580–82, which seem to anticipate removing CIP costs from base rates and recovering them through the CCRA. It would create administrative inefficiencies for one utility to use a CIP cost-recovery system different from those used by all other utilities and represent a departure from current practice of how the bulk of CIP costs are currently collected. Further, the disputes underlying this recommendation have been properly resolved.

7) **Impact of Updated Sales Forecasts and Commodity-Pricing Forecasts on the Demand and Commodity Cost-of-Gas Rates—**The Commission requested information on how updated sales forecasts and commodity-pricing forecasts would affect its per-dekatherm demand and/or commodity cost-of-gas rates. It required these filings in both this docket and the base-cost-of-gas docket, G-011/MR-13-732.

MERC's gas costs are handled similarly to CIP costs for rate-recovery purposes—they are treated as flow-through costs and recovered dollar for dollar, not aggregated with other costs and recovered solely through base rates.[12] As with CIP costs, baseline gas costs are built into base rates, and differences between those costs and actual costs are trued up monthly through an automatic rate-adjustment mechanism. At the beginning of every gas rate case, the filing utility proposes a new base cost of gas, which is used during the interim-rate period and as a starting point in determining the new base cost of gas that will be built into final rates.

The cost of gas was not a contested issue in this case; the parties agreed and the Administrative Law Judge recommended that the final base cost of gas should be calculated using the Department's updated test-year sales figures and the updated (March 27, 2014) commodity cost of gas on the New York Mercantile Exchange (NYMEX). This is consistent with normal regulatory practice.

Commission staff pointed out, however, that the March 27 NYMEX price appeared to include significant residual price consequences from the rupture and shutdown of the TransCanada natural-gas pipeline during the last heating season. Staff suggested careful examination of whether those impacts were likely to continue to affect gas prices throughout the period for which rates were being set.

This concern prompted further discussions between the Department and the Company. The parties ultimately agreed that MERC would make a filing updating the base cost of gas to reflect NYMEX pricing estimates for January through December 2015, that these cost estimates would be used as the new base cost of gas, and that these cost estimates would be used to adjust the revenue deficiency amount attributable to uncollectible expense. That filing has been made.

The Commission concurs with the parties that this adjustment will result in a more accurate base cost of gas and will adopt it, as well as requiring the use of these figures in calculating the new gas-storage balance.[13] Finally, the Commission concurs with the Administrative Law Judge that

[12] This ratemaking treatment is authorized under Minn. Stat. § 216B.16, subd. 7.

[13] These adjustments necessarily entail declining to adopt the Administrative Law Judge's recommendations in ¶ 202.

in future rate-case filings the Company should continue to provide detailed documentation on the preparation of its test-year sales analysis, which is critical to determining the base price of gas, and the ordering paragraphs will so provide.

IV. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held a formal evidentiary hearing and three public hearings. He reviewed the testimony of 25 expert witnesses and examined 83 hearing exhibits. He read some 95 written comments submitted by members of the public.

He received and reviewed initial and reply post-hearing briefs from the parties, as well as their proposed findings of fact and conclusions of law. He made 716 findings of fact and conclusions of law and made recommendations on all stipulated, settled, and contested issues based on those findings and conclusions.

The Commission has itself examined the record, considered the report of the Administrative Law Judge, considered the exceptions to that Report, and heard oral argument from the parties. Based on the entire record, the Commission concurs in most of the Administrative Law Judge's findings and conclusions. On some issues, however, the Commission reaches different conclusions, as delineated and explained below. And on a few issues it provides technical corrections and clarifications.

On all other issues, the Commission accepts, adopts, and incorporates the ALJ's findings, conclusions, and recommendations.

FINANCIAL ISSUES

V. Discount Rates for Post-Retirement Employee Benefits

A. Introduction

MERC calculated test-year expenses for its pension, post-retirement medical, and post-retirement life-insurance plans using actuarial analysis. Actuarial analysis relies on a number of assumptions, including mortality tables, company-specific retirement rates, expected return on plan assets, and a discount rate.

The discount rate is used to adjust a plan's future cost to a present value. Thus, the lower the discount rate used in the calculation, the higher the calculated test-year expense; the higher the discount rate, the lower the calculated expense.

MERC used an expected return on plan assets of 8.00% and the following discount rates by plan:

Plan	Discount Rate
Pension	4.95%
Post-Retirement Medical	
Administrative Plan	4.05%
Non-administrative Plan	4.80%
People's Energy Medical	4.45%
Post-Retirement Life	4.80%

MERC determined the discount rates according to Accounting Standards Codification Topic 715 (ASC 715), which requires that a discount rate reflect the possibility that a utility may have to settle its benefit payments in the near term as a result of financial distress. The Company used a model that theoretically purchased high-quality corporate bonds to settle each plan's future benefit payments. From the theoretically purchased bonds, MERC determined a single rate that equated the market value of the bonds purchased to the discounted value of each plan's expected future benefit payments.

B. Positions of the Parties

1. The Department

The Department recommended setting the pension-plan discount rate at eight percent to match the plan's expected return on assets. The Department's position was that the pension-expense calculation for ratemaking purposes did not need to be governed by accounting practices implemented for another purpose.

The Department stated that, while companies update their ASC 715 pension expense annually based on changing conditions, the Commission must set a rate that can remain in place until MERC's next rate case. Moreover, the Department contended that the Company was unlikely to experience financial distress that would force it to settle its pension benefits in the near term, as assumed by ASC 715. The Department argued that it was unreasonable to charge ratepayers a premium for a contingency that was unlikely to occur.

Finally, the Department argued that the Commission had approved the approach of setting the discount rate equal to the expected return on plan assets in Xcel Energy's 2012 rate case.[14]

2. The Company

MERC argued that setting the discount rate equal to the expected return on plan assets would not accurately reflect MERC's reasonable costs of doing business. The Company asserted that the appropriate discount rate to use to value costs should be independently calculated based on MERC's specific circumstances and that its circumstances did not support using an eight-percent discount rate to calculate test-year pension expense.

[14] Docket No. E-002/GR-12-961.

MERC also argued that the pension plan in Xcel's 2012 rate case was not comparable to MERC's pension plan because Xcel used a different cost method to account for the costs of the plan. Instead, MERC argued that its pension plan was similar to the one at issue in CenterPoint Energy's 2013 rate case.[15]

In the CenterPoint case, the Commission rejected the ALJ's recommendation that test-year employee-benefit expense be calculated using a discount rate set equal to the expected return on plan assets. The Commission reasoned that the discount rate must be supported by the factual record in each case and concluded that the five-year historical average discount rate was most appropriate in that case.

As an alternative to its recommended discount rate, MERC proposed using the five-year historical average approach adopted by the Commission in the CenterPoint rate case.

3. The Department's Response

The Department disagreed with the approach taken in CenterPoint, arguing that averaging five unreasonably low discount rates would still result in an average discount rate that was too low. The Department requested that, if the Commission decided to adopt MERC's alternative proposal, the Commission send the issue back to the ALJ for further factual development.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge believed that the Department had the better policy argument. However, the ALJ found that MERC's circumstances were indistinguishable from those in the CenterPoint rate case and concluded that MERC should use a five-year historical average to calculate its discount rate.

D. Commission Action

The Commission agrees with the ALJ's conclusion that MERC should use a five-year historical average discount rate. However, the Commission does not agree that the Department has the better policy argument in this instance.

The Department is correct that the Commission is not bound by accounting standards when calculating pension expense for ratemaking purposes. However, following ASC 715 will help ensure that MERC's pension plan is fully funded and that utility employees are protected in the event of a financial crisis. While a utility is less likely than other companies to experience financial distress, the Commission deems it prudent in this case to err on the side of ensuring that MERC's pension plan is adequately funded.

The appropriate discount rate varies from year to year, but changes are only reflected in utility rates when a rate case is decided. MERC's proposed discount rate is significantly lower than average. As in the CenterPoint rate 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. A discount rate based on the five-year average is more reasonable than a discount rate

[15] Docket No. G-008/GR-13-316.

determined at a single point in time and strikes a reasonable balance between the Department's and the Company's proposed discount rates.

For these reasons, the Commission will adopt the ALJ's Finding 250 and require MERC to calculate test-year pension expense using a discount rate equal to the five-year historical average of discount rates. For the sake of consistency, the Commission will also require MERC to use five-year historical average of discount rates to calculate test-year post-retirement medical and life-insurance expense.

In its exceptions to the ALJ's Report, the Department argued that it had inadequate opportunity to develop the record on using a five-year average discount rate, since both MERC's alternative proposal and the CenterPoint decision occurred after the close of the evidence in this case. However, the record does contain evidence of the Company's discount rates for the years 2009–2013.[16] The Commission believes that the record on discount rates is sufficiently complete.

The Commission acknowledges that it has taken a different approach to discount rates in the CenterPoint and, now, MERC rate cases than it took in Xcel's most recent rate case. Further exploration of the best approach going forward will provide clarity that will benefit both utilities and ratepayers. The Commission will therefore open a generic inquiry into how discount rates should be derived and applied in calculating future pension expenses for setting rates in Minnesota.

In their exceptions, the Department and MERC also recommended correcting typographical errors in Findings 209 and 254. Because correcting these findings will enhance their accuracy, the Commission will correct them.

VI. Property-Tax Expense

A. Introduction

In MERC's initial filing in this case, the Company estimated its property taxes for the 2014 test year to be $7,314,733.

In response to information requests from the Department, MERC lowered the test-year inflation rate, which resulted in a $48,864 reduction in test-year property taxes. MERC further reduced its property taxes by $70,000 to reflect revised tax-assessment estimates from the Kansas Attorney General, for a total reduction of $118,864.

B. Positions of the Parties

1. The OAG

The OAG argued that MERC's request for property taxes is unreasonably inflated, claiming that the test-year amount represented an increase of more than 10% in two years. The OAG stated that it had reviewed tax statements for MERC's property in Washington County that showed that its property taxes there decreased from 2013 to 2014. The OAG recommended that the Commission

[16] Direct Testimony of Michelle St. Pierre, Attachment 21 (March 4, 2014).

require MERC to use the Company's estimated 2012 property taxes of $6,624,033 as its test-year property-tax expense.

2. The Company

MERC responded that the tax statements from Washington County did not accurately represent its statewide taxes. The Company argued that the OAG's proposed adjustment was inaccurate because it failed to account for any change in MERC's 2013 or 2014 property-tax expense. MERC stated that its actual tax liability for 2012 was greater than the estimated 2012 amount that the OAG recommended using for the Company's 2014 test year.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that MERC's actual tax liability for 2012 was greater than the OAG's estimate of MERC's 2014 taxes and that MERC's expectation of still higher property tax obligations during 2014 was well grounded in the hearing record. The ALJ found that MERC's recommended property-tax reduction of $118,864 was appropriate.

D. Commission Action

The Commission concurs with the Administrative Law Judge on this issue and will approve 2014 property taxes of $7,195,869. The record shows that MERC's property taxes increased substantially during the period from 2012 to 2014. Under these circumstances, using MERC's estimated 2012 property taxes, which ended up being less than the actual taxes the Company paid for that year, would not be reasonable.

Finally, the parties agreed that MERC should keep the Commission apprised of the status of its ongoing tax litigation in Minnesota and Kansas, and to remit any refunds due to ratepayers. The Commission finds this plan to be reasonable and will include it below in the ordering paragraphs.

VII. Bad-Debt Expense

A. Introduction

MERC initially proposed to recover $1,765,884 in test-year bad-debt expense. In rebuttal testimony, MERC revised its estimate to $2,016,410, primarily due to increased forecast sales.

To determine test-year bad debt, MERC first divided its average uncollectable expenses by its average tariffed revenues for the years 2010–2012 to derive a historic bad-debt percentage of 0.650401%. MERC then applied this percentage to the sum of its 2014 test-year forecasted revenues and an assumed rate increase to calculate bad debt. The assumed rate increase is slightly less than MERC's proposed rate increase to avoid a circular reference (since bad-debt expense is a component of the revenue requirement).

B. Positions of the Parties

1. The Department

The Department argued that averaging MERC's historic bad-debt expense overstates the test-year expense because there is a clear downward trend in MERC's bad debt. Furthermore, the

Department argued that MERC had not justified using the 2010–2012 historic average when newer data from 2013 data were available. The Department recommended that MERC use the more current 2013 bad-debt percentage of 0.549760% and recalculate its test-year bad-debt expense based on the rate increase ultimately approved in this case.

2. The OAG

The OAG agreed with the Department that MERC's requested level of bad debt overstated the expense in light of the downward trend in bad debt from 2010 to 2013, as well as external factors such as the low cost of natural gas and an improving economy. The OAG calculated that MERC's average bad debt during the period from 2010 to 2013 was $1,436,488. Reasoning that bad debt for 2014 would be slightly lower than this historical average, the OAG recommended a test-year bad-debt expense of $1,350,000.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that MERC should use the average percentage of tariffed revenue from the three most recent years (2011, 2012, and 2013) and apply this percentage to MERC's 2014 test-year forecasted revenues plus an assumed rate increase of $12,000,000. The ALJ found that this method relied upon the most recent figures, accounted for variability in the bad-debt rates, and best carried forward the Commission's earlier approaches to these issues.

D. Commission Action

Under the circumstances of this case, the Commission disagrees with the ALJ's recommendation to use a historical average to calculate bad-debt expense. The Commission often employs averaging in ratemaking to smooth costs that vary from year to year. However, where the variation follows a clear trend, averaging can obscure the trend, resulting in inaccurate rates.

Here, MERC's bad debt, as a percentage of revenue, has decreased consistently from 2011 to 2013. In light of this trend, the Commission concurs with the Department that MERC's 2013 bad-debt percentage provides the best predictor of MERC's bad debt going forward.

The Commission also disagrees with the ALJ's recommendation to apply the bad-debt percentage to an assumed rate increase of $12,000,000. MERC used the $12,000,000 figure in its calculation of test-year bad debt on the assumption that the Commission would approve its proposed rate increase of $12,159,454. The Commission will instead require MERC to calculate its test-year bad debt based on the rate increase approved in this case.

For the foregoing reasons, the Commission will require MERC to use the 2013 bad-debt percentage of 0.549760% and apply it to the sum of the following figures, as determined in this rate case: test-year forecasted revenues at present rates, the new base cost of gas, and the approximate revenue deficiency, rounded down to the closest million to eliminate the circular reference.

VIII. Inflation Rates for Non-Fuel O&M Expenses

A. Introduction

To determine its test-year non-fuel operations and maintenance (O&M) expenses, MERC started with its actual 2012 non-fuel O&M costs, applied inflation factors for calendar years 2013 and 2014, and then made "known and measurable" adjustments to certain expenses.

MERC's calculated inflation for the period between 2012 and 2014 was 3.74% for non-labor O&M costs and 5.27% for labor costs. MERC determined the non-labor inflation rate by averaging CPI (consumer price index) projections from multiple sources. MERC based the labor inflation rate on recent union contract wage increases.

B. Positions of the Parties

The OAG argued that inflating 2012 expenses for two years overstated test-year O&M expenses and that MERC should only add one year's worth of inflation to its historical O&M expenses. The OAG further argued that the CPI projections MERC used to determine its non-labor expenses were economy-wide and that an "internal" inflation projection based on MERC's historical O&M expenses would be more accurate. Finally, the OAG argued that MERC used too few CPI sources (three) to calculate 2013 inflation.

MERC responded that it was entitled to use a 2014 test year and that the Company based its projections on 2012 data because that was most recent year for which complete data were available. MERC argued that inflating historical expenses based on external CPI projections and then adjusting for known and measurable changes was a reasonable approach to calculate test-year O&M expenses.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that the OAG's one-year-inflation approach would unreasonably exclude costs related to events that have an impact on the 2014 test year and should be recoverable. The ALJ also rejected the OAG's recommendation that MERC use an internal inflation rate. The ALJ found that MERC's method reflected the Company's efforts to balance service with new efficiencies, produced results particularized to MERC's situation, and was identical to the method the Company used in its last two rate cases.

D. Commission Action

The Commission concurs with the Administrative Law Judge and will adopt his findings, conclusions, and recommendation. The Commission will not require MERC to adjust the methodology it used to develop test-year non-fuel O&M expense: The Company's proposed inflation factors are sound, supported in the record, and consistent with longstanding practice. The one-year approach proposed by the OAG would not reflect the actual inflation experienced by MERC and could not reasonably form the basis for an alternative inflation factor.

IX. Customer-Relations Costs

A. Introduction

MERC has been outsourcing its customer-relations operations since its holding company, Integrys, bought the company in 2006. Its third-party vendor, Vertex, handles customer billing and payment processing, operates a call center to field customer inquiries, and manages the routine dispatch of installation and repair crews.

Integrys is in the process, however, of developing the capacity to deliver these services through another of its subsidiaries, Integrys Business Support (IBS). IBS, the holding company's centralized service company, is developing a full-service customer-relations department that will replace Vertex and provide customer-relations services to all six of Integrys's regulated utilities. IBS calls the new suite of customer-relations services the "Integrys Customer Experience (ICE)"; ICE is expected to become fully operational in 2016.

MERC's test-year costs therefore include a full year of payments to Vertex, including a $408,455 contract-price increase, and a full year of ICE development costs, $322,226.

B. Positions of the Parties

The OAG challenged including the costs of two separate customer-service systems in test-year costs, arguing that they couldn't both be used and useful. The Company argued that it was perfectly proper to charge ratepayers for both the costs of the current system and the costs of developing its future system, but offered, in the alternative, to defer the ICE-development costs as a regulatory asset for rate recovery once the ICE system was in place.

The OAG responded that deferring the costs as a regulatory asset would be acceptable as long as (1) the costs are subject to review for reasonableness and prudence in the next rate case; (2) the amortization period is set in the next rate case, not now; and (3) the Company earns no return on these expenses, which were not listed as Construction Work in Progress. The Company concurred.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Vertex costs were used and useful—and therefore rate-recoverable—because Vertex was providing critical customer-relations services to the Company and its ratepayers. He also recommended adopting the parties' alternative position on the ICE costs, treating those costs as a regulatory asset and deferring them to the next rate case. He recommended a three-year amortization period.

D. Commission Action

The Commission agrees that the most reasonable course of action is to defer these costs, together with (1) their related $29,070 in depreciation and return on cross charges and (2) future, actual ICE costs, plus their related depreciation and return on cross charges, with all costs subject to review for reasonableness and prudence in the Company's next rate case.

The Commission concurs with the OAG that the amortization period for costs determined to be rate-recoverable in the next rate case should be set in that case—when the Commission can make a decision based on then-current facts—not in this one. The Commission therefore declines to adopt the Administrative Law Judge's recommendation to set the amortization period for those deferred costs at three years.

Finally, to highlight and clarify the above decisions the Commission will adopt the modification to ALJ Finding 276 recommended by the OAG, set forth below:

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

X. Deferred Tax Asset for Net Operating Loss Carryforward

A. Introduction

The Company included in test-year rate base an approximately $2,200,000 deferred tax asset that resulted from its parent company's net operating losses in 2012 and 2013. The net operating losses, which can be carried forward to reduce future income taxes, were due primarily to the availability of accelerated and bonus depreciation under federal economic stimulus legislation.

B. Positions of the Parties

1. The OAG

The OAG challenged the inclusion of this asset in rate base on several grounds. It claimed that MERC, as a subsidiary of Integrys, was not a legitimate taxpayer and was not entitled to claim either net operating losses or the associated deferred tax credit. It claimed that MERC had failed to produce evidence that it had contributed to the net operating losses and was therefore entitled to share in the deferred tax asset.

The OAG questioned the applicability of an IRS Private Letter Ruling supporting MERC's claim that it must normalize its tax liability in this way to meet IRS requirements, arguing that the taxpayer in the Ruling was not, like MERC, a subsidiary of a holding company.

Finally, the OAG argued that the deferred tax asset should not be included in rate base because it would be effectively consumed on January 1, 2014, when the Company would begin to accrue income tax liability exceeding the asset.

2. The Company

MERC acknowledged that this type of deferred tax asset was not commonly seen in utility regulation, but argued that its unusualness did not affect its legitimacy. The Company argued that it had contributed to its parent's net operating losses—demonstrating in responses to information requests that it had booked substantial amounts of accelerated and bonus depreciation in 2012 and 2013—and pointed out that it had joint and several tax liability with its parent in any case.

MERC argued that its 2014 income tax liability would not consume the entire deferred tax asset on the first day of 2014, but that the liability would accrue gradually. The Company emphasized that it interpreted IRS regulations as requiring it to treat the deferred tax asset as it proposed or lose future eligibility for accelerated and bonus depreciation. And the Company interpreted the IRS Private Letter Ruling as applicable to itself, seeing no basis for distinguishing between a stand-alone utility and a subsidiary utility for the tax purposes at issue.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that MERC's status as a subsidiary of a holding company did not preclude it from generating tax liabilities or from securing the tax benefits of accelerated and bonus depreciation, including the resulting net operating losses and deferred tax assets. He found that the Private Letter Ruling from the IRS, while not controlling, appeared to apply to MERC's facts. And he found that MERC was required by the federal tax code to use the tax normalization procedures it proposed.

The Administrative Law Judge recommended including the proposed $2,200,000 deferred tax asset in rate base.

D. Commission Action

The Commission concurs with the Administrative Law Judge and approves the inclusion of the approximately $2,200,000 deferred tax asset in test-year rate base. MERC's status as a subsidiary company does not preclude it from reflecting the impact of income taxes in its rates.

Further, as MERC clarified in rebuttal testimony, its accelerated and bonus depreciation did contribute to Integrys's ability to claim net operating losses in 2012 and 2013 and benefitted ratepayers by offsetting rate base. In 2012, the Company claimed some $23,673,577 in accelerated depreciation, and in 2013, it claimed approximately $22,630,741.[17]

For all these reasons the Commission will approve the inclusion of the deferred tax asset in rate base.

XI. Employee-Benefit Contributions as Regulatory Assets

A. Introduction

MERC initially proposed to include net regulatory assets of $19,642,806 in rate base. The majority of that amount—some $18,837,482—was related to employee benefits.

From 2012 to 2014, MERC contributed more to its trust funds for employee pensions and other post-retirement benefits than it recognized in expenses. MERC argued that its proposal to include these employee-benefit "prepayments" in rate base was consistent with the Commission's treatment of employee benefits in the Company's last rate case.[18] In that case, at the OAG's

[17] Exhibit 36, J. Wilde Rebuttal at 37.

[18] G-007, 011/GR-10-977.

urging, MERC agreed to reflect the cumulative difference between benefit funding and expense from 2007 through 2011 in rate base. The Commission accepted the ALJ's finding that MERC had reduced rate base by $71,159 and that that amount accurately reflected the difference between funding and expense.

MERC also argued that the Commission had authorized including prepaid pension contributions in rate base as part of a settlement in Xcel Energy's 2010 rate case.[19]

B. Positions of the Parties

1. The Department

The Department recommended removing $11,281,942 of regulatory assets from rate base, most of which was associated with benefit funding, for several reasons.

First, the Department argued that the Xcel rate-case settlement lacked precedential value, and that the agreement between the OAG and MERC in MERC's last rate case did not support the Company's proposal because it resulted in ratepayer-supplied funds being excluded from rate base, whereas here MERC proposes to include Company-supplied funds in rate base.[20]

Second, the Department maintained that MERC's proposal would result in double recovery because MERC already recovers both the cost of employee-benefit expenses through its test-year income statement and a return on those costs through the cash-working-capital component of rate base.

Third, the Department argued that the current overfunded status of MERC's benefit funds is a temporary situation, since the funding level fluctuates over time depending upon contribution rates and market conditions, and that temporary overfunding is not a sufficient justification for permanent rate-base recovery.

Finally, the Department argued that once MERC makes a contribution to a benefit trust fund, the Company no longer has use of the funds or receives earnings on them, and it would therefore be unreasonable for MERC to earn a return on the benefit funds as though they remained part of its rate base.

2. The Company

MERC disputed the Department's claim that it already receives a return on employee-benefit contributions through the cash-working-capital component of rate base. MERC argued that the pension assets and liabilities it has proposed to include in rate base are neither accounts receivable nor accounts payable, and would therefore not be captured in the lead/lag study and included in cash working capital.

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[19] E-002/GR-10-971.

[20] Although the OAG has not taken a position on rate-base treatment of employee-benefit prepayments in this case, at oral argument the OAG stated that its agreement with MERC in the Company's last rate case pertained only to excluding ratepayer-supplied funds from rate base.

MERC further argued that, even though it cannot withdraw the prepaid pension funds or otherwise use them, the earnings on the fund are used to offset future pension expense, reducing the overall revenue requirement and benefitting ratepayers. Because prepaying pension costs benefits ratepayers by reducing future liabilities for benefit payments, MERC argues that these are expenditures on which the Company should earn a rate of return.

Finally, MERC stated that if the Commission removes the assets and liabilities associated with its benefit trust funds from rate base, then corresponding deferred taxes should also be removed from rate base. The Minnesota jurisdictional amount of these taxes is $4,294,542.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with the Department and recommended that the Commission require MERC to reduce rate base by $11,281,942 for the Regulatory Assets and Liabilities adjustment. The ALJ also recommended that the Commission remove $4,294,542 of corresponding deferred taxes, for a net adjustment reducing rate base by $6,987,400.

D. Commission Action

The Commission concurs with the ALJ and the Department on this issue. MERC's employee benefits are unlike typical rate-base assets on which a utility is allowed a rate of return: The benefits are maintained in a trust fund outside the Company; once MERC makes a contribution, it no longer has any control over or use of the funds for normal business purposes.

Normally, these assets are not included in rate base. The Commission does not view either the 2010 Xcel rate-case settlement or the agreement between MERC and the OAG in the Company's last rate case as precedential. In those cases, the issue was agreed to among the parties and not presented to the Commission as a disputed issue for analysis and resolution.

Finally, the Department maintained that MERC already earns a return on employee-benefit expenses through cash working capital. MERC has not carried its burden to show that inclusion of the employee-benefit assets in rate base would not result in double recovery.

For these reasons, the Commission will adopt the ALJ's proposed Findings 498 through 501 and require MERC to reduce rate base by $11,281,942 for the Regulatory Assets and Liabilities adjustment and its related deferred taxes of $4,294,542, for a net adjustment that reduces the rate base by $6,987,400.

Finally, in its exceptions, MERC argued that the ALJ incorrectly found that the rate-base adjustment in MERC's last rate case resulted from the multi-year "averaging" of cumulative benefit contributions and liabilities. According to MERC, there was no averaging involved. Rather, the adjustment simply reflected the cumulative difference between funding and expense from 2007 through 2011. The Commission agrees and will modify Findings 489 and 490 accordingly.

XII. Travel, Entertainment, and Related Employee Expenses

A. Introduction

MERC provided information on its travel, entertainment, and related employee expenses, as required by Minn. Stat. § 216B.16, subd. 17. Included in this submission were details as to travel expenses, entertainment expenses, and separately itemized expenses for MERC's board of directors and ten highest-paid employees.

The Department reviewed MERC's travel and entertainment expenses and recommended excluding $7,770 of expenses that did not appear to be reasonably related to Minnesota regulated utility operations. The Department also recommended that the Commission exclude corporate aircraft expenses of $956. The Company accepted the Department's proposal to exclude these expenses.

The Department also concluded that employee travel and entertainment expenses allocated to MERC from Integrys Business Support (IBS), MERC's service company, should have been filed for review. MERC agreed to provide all travel and entertainment expenses, including expenses related to its affiliates' employees, in future rate-case filings.

B. Positions of the Parties

1. The OAG

The OAG argued that MERC's failure to itemize the IBS expenses violated section 216B.16, subdivision 17, and that, under these circumstances, it would be unreasonable to require ratepayers to pay for these expenses. The OAG recommended disallowing all of the IBS travel and entertainment expenses, as well as all of MERC's own employee travel and entertainment expenses.

The OAG further recommended that the Commission disallow dues for membership in several professional organizations because MERC did not separately itemize them or establish that they benefit its customers.

Finally, the OAG recommended that MERC make several changes to its reporting of employee travel and entertainment expenses in future rates cases, including excluding all expenses incurred outside Minnesota unless the description justifies an allocation to Minnesota and allocating only a portion of travel and entertainment expenses for items not specific to Minnesota.

2. The Company

MERC argued that the plain language of Minn. Stat. § 216B.16, subd. 17, only requires disclosure of the filing utility's expenses, not expenses of its affiliates. Thus, MERC did not believe that it was required to separately itemize expenses from IBS.

As to membership dues, MERC stated that because these expenses were paid through IBS, they were not included in the Company's itemized filing. MERC argued that these dues should be included in its operating expenses because ratepayers benefit from the Company's membership in professional organizations.

Finally, MERC disagreed with the OAG that all non-Minnesota travel and entertainment expenses should be excluded unless the description justifies an allocation to Minnesota. However, MERC did agree that any cost not specific to Minnesota would be allocated to the Company based upon the allocation factors in MERC's direct testimony.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge disagreed with the OAG's recommendation to exclude all expenses incurred outside of Minnesota, stating that, for a wholly owned subsidiary like MERC, whose parent company has significant central-office operations in another state, out-of-state travel can fulfill an important purpose that benefits ratepayers. The ALJ found that, subject to the modifications agreed to by MERC, the Company's travel, entertainment, and other employee expenses were reasonable and should be approved.

D. Commission Action

The Commission concurs with the ALJ and adopts his findings, conclusions, and recommendation. While MERC should have itemized the IBS expenses, the OAG's recommendation that they be excluded entirely is not well founded. First, the expenses are necessary for the provision of utility service, since MERC employees must travel out of state to transact business with MERC's parent company.

Moreover, a blanket exclusion of the IBS expenses would be unduly punitive, since MERC did not intend to violate the law. Finally, the Company has agreed to itemize these expenses in future rate cases. Thus, beginning with MERC's next rate case, the IBS expenses will be itemized and receive greater scrutiny.

With respect to MERC's membership dues, the Commission generally agrees with MERC that its ratepayers benefit from the Company's membership in professional organizations. Membership in such organizations allows employees to stay abreast of developments in their fields, with a resulting effect on service quality and efficiency.

However, the Commission finds that membership in the Edison Electric Institute is unnecessary for the provision of natural-gas service. The Commission will therefore require MERC to reduce Administrative and General Expenses by $3,496 for dues to the Edison Electric Institute, as well as the $7,770 in general travel and entertainment expenses and $956 in corporate aircraft expenses that MERC has agreed to exclude.

Finally, the Commission will require the Company in future rate-case filings to (1) meet the reporting requirements of Minn. Stat. § 216B.16, subd. 17 for all travel and entertainment expenses, including expenses related to employees working for MERC affiliates, and (2) allocate any costs not specific to Minnesota based on the allocation factor MERC files in its direct testimony and identify which costs have been allocated.

COST OF CAPITAL ISSUES

XIII. Cost of Equity

A. Introduction

In determining just and reasonable rates, the Commission is required to

> 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*.[21]

One of the critical components of that fair and reasonable return upon investment is the return on common equity, which—together with debt—finances the utility infrastructure. The Commission must set rates at a level that permits stockholders to earn a fair and reasonable return on their investment and permits the utility to continue to attract investment.

In short, the Commission must determine a reasonable cost of equity and factor that cost into rates. It would normally begin by examining the price of the utility's stock, but MERC is a wholly owned subsidiary of Integrys Energy Group and has no publicly traded common stock. Its cost of common equity—essential to determining overall rate of return and the final revenue requirement—must therefore be inferred from market data for companies that present similar investment risks.

B. The Analytical Tools

The Company, the Department, and the OAG conducted full cost-of-equity studies and based their analysis on comparison groups of utilities they considered similar enough to MERC to serve as proxies in determining the Company's cost of equity. All three used both the Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance, and the Capital Asset Pricing Model (CAPM), which the Commission has historically used as a secondary, corroborating resource. The Company also conducted a third analysis using the Risk Premium (RP) model, which the Commission has historically relied on less heavily, considering the model prone to producing volatile and unreliable outcomes.

The DCF model uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is high enough to induce investment. The model is derived from a formula used by investors to assess the attractiveness of investment opportunities by determining the net present value, or price per share, of a company's stock. It uses three inputs—dividends, market equity prices, and growth rates.

The CAPM model estimates the required return on an investment by determining the rate of return on a risk-free, interest-bearing investment; adding a historical risk premium determined by subtracting that risk-free rate of return from the total return on *all* market equities; and multiplying the remainder by beta, a measure of the investment's volatility compared with the volatility of the market as a whole.

[21] Minn. Stat. § 216B.16, subd. 6, emphasis added.

The RP Model determines the cost of equity by adding to current corporate bond yields a premium reflecting the greater returns realized by equity holders over various historical periods.

C. Positions of the Parties

MERC recommended a return on equity of 10.75%. That number was derived by applying all three analytical models discussed above to each company in MERC's comparison group, synthesizing the results to arrive at a baseline return on equity, adding an adjustment for flotation costs,[22] and adjusting the final figure upward to reflect generic and company-specific factors that the Company argued increased its risk.

The Department recommended a return on equity of 9.29%. That number was derived by completing a DCF analysis on each company in the Department's comparison group and evaluating the range of results in light of the range of the Department's CAPM results. The Department, like MERC, added a flotation adjustment to the final figure.

The OAG recommended a return on equity of 8.62%. That number was derived by completing two variations of the DCF analysis on each company in the OAG's comparison group and then incorporating the results of its market-to-book and CAPM analyses. The OAG opposed adding an adjustment for flotation costs, on grounds that returns on equity are already inflated in cases such as this, in which the company's market to book ratio is significantly higher than one.

The parties' positions are further described below.

1. The Company

MERC recommended a return on equity of 10.75%, which it derived by applying all three analytical models to each company in its comparison group, synthesizing the results, adding a flotation adjustment, and adjusting the final figure upward to reflect generic and company-specific factors that the Company believed increased its business and investment risks.

MERC argued that, since all analytical models have strengths and weaknesses, using three recognized models will produce a more robust result than using just one. Further, the Company argued that the DCF model—the one the Commission has generally found most trustworthy and relied upon most heavily—has two weaknesses that must be compensated for.

First, the model is somewhat circular; it involves a regulatory agency setting rates of return based on investors' expectations, which are themselves based on rates of return set by other regulatory agencies in earlier cases. This is a structural limitation, and the Company made no adjustment to its DCF results to reflect this feature of the model.

Second, the model does not take into account the disparity between the book value at which utility assets are valued and on which regulators base authorized returns, and the market values investors typically perceive and rely on in making their investment decisions. This disparity, the Company argued, understates and undercompensates for risk by making utilities' debt ratios appear lower than they are. The Company made an upward adjustment to its DCF results to account for this

[22] Flotation costs are the fees and expenses a company incurs to issue securities.

feature, calling it a “leverage adjustment.” It made the same adjustment to its CAPM and RP calculations.

MERC also argued that the cost of equity should be adjusted upward to account for company-specific risk factors not adequately accounted for in the models: the relatively small size of the Company, its significant concentration of large industrial customers (whose usage varies with swings in the economy and who may be able to bypass the Company’s system), its relatively high earnings variability, relatively low interest coverage, and relatively high five-year average operating ratio. None of these risks are easily quantifiable, and the upward adjustment built into the Company’s cost-of-equity number was based on the professional judgment and expertise of its expert witness.

MERC argued that the flotation adjustment built into its final cost figure was supported by past Commission practice and necessary to prevent the dilution of equity by issuance costs.

2. The Department

The Department recommended a return on equity of 9.29%. That number was derived by completing a DCF analysis on each company in the Department’s comparison group and evaluating the range of results in light of the Department’s CAPM results. The Department, like MERC, added a flotation adjustment to the final figure.

The Department strongly recommended basing the Company’s cost of equity on the DCF analytical model and using the other models mainly as reasonableness checks. The agency stated that it used the DCF model because that model has proved to be the most trustworthy over the decades, is more transparent and objective than the other two models, and has been relied upon more consistently by the Commission.

The Department rejected MERC’s claims that its cost of equity should be adjusted upward to account for its size, the book-value/market-value dichotomy for which it requests a leverage adjustment, its reliance on large industrial customers, or any of the company-specific financial factors cited (interest coverage, earnings variability, operating ratio).

The agency stated that the leverage adjustment was unnecessary because investors are not markedly unsophisticated, and the book-value/market-value dichotomy is a fundamental feature of utility stocks understood by all investors. The agency argued that no adjustment was needed for the Company’s size, heavy concentration of large industrial customers, or any of the company-specific financial factors cited, because the integrity of the comparison group ensured that individual differences would offset one another and be neutralized by the companies’ overarching similarities.

The agency concurred with the Company on the need for a flotation adjustment to prevent the dilution of equity by issuance costs.

3. The OAG

The OAG recommended a return on equity of 8.62%. That number was derived by completing two variations of the DCF analysis, described by the OAG as “two methods rooted in the Discounted

Cash Flow ('DCF') construct: the standard single-stage or 'constant growth' DCF analysis and the market-to-book method."[23]

The OAG's application of the single-stage or constant-growth DCF model differed from conventional applications in that, instead of using projected growth in earnings per share as a proxy for dividend growth, it used a blend of projected growth in earnings per share, dividends, book value, retention ratios, returns, total number of shares, and market-to-book ratio. The OAG argued that this adaptation was required to offset, at least in part, the inflated cost-of-equity figures that the DCF model yields when applied to companies whose market-to-book ratios significantly exceed one.

The OAG also conducted a market-to-book analysis, estimating the cost of equity as the sum of the Company's internal return and its external returns. This method relies on analysts' projections of a company's future retention ratios, returns on equity, growth in number of shares, and market-to-book ratios. The OAG also conducted a CAPM analysis, which it used only as a reasonableness check.

The OAG opposed any adjustment for flotation costs, arguing that the methods commonly used to set the cost of equity for utilities nearly always inflated that cost, creating a cushion that both covered flotation costs and unreasonably enriched shareholders.

D. The Recommendation of the Administrative Law Judge

The ALJ made extensive findings on the DCF and CAPM analytical models and on the parties' application of these models to MERC. He rejected the Company's execution of the remaining model, RP, as invalid, without reaching conclusions on the validity or usefulness of the model itself.[24] He rejected the OAG's use of a weighted blend of multiple factors to calculate dividend growth rates, finding that the standard method of using earnings-per-share had more factual support and wider acceptance.[25]

The ALJ found that the CAPM model raised difficult issues in execution and endorsed the Department's decision to use CAPM only as a reasonableness check.[26] He found that the best practice for setting the cost of equity was to compare the results of a DCF analysis with the results of other analyses, such as the CAPM.[27] He essentially found that the Department's methodological approach to and execution of the DCF and CAPM models were superior to the Company's and the OAG's.[28] He treated the Department's DCF outcome as the baseline for determining the appropriate cost of equity.[29]

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23 OAG Initial Brief at 21.

24 ALJ's Report at ¶¶ 165-166.

25 ALJ's Report at ¶¶ 122-123.

26 ALJ's Report at ¶¶ 155 and 157.

27 ALJ's Report at ¶¶ 156.

28 ALJ's Report at ¶¶ 122, 123, 131, 153-154, 156-157, 165-166, 171.

29 ALJ's Report at ¶¶ 171-172.

At that point, however, the ALJ adopted the Department's CAPM outcome, 9.79%, instead of its DCF outcome, 9.29%, finding that the DCF outcome understated the cost of equity by failing to adjust for MERC's having a higher risk profile than the comparison group used in the Department's DCF analysis.[30] As further evidence that the Department's CAPM analysis "yields a better and more reasonable result" than its DCF analysis, the ALJ cited the following factors:

- The 9.79% return was just one basis point from MERC's updated DCF analysis, which rendered a return of 9.8%.

- The 9.79% return was supported by the Department's ECAPM (a variation of CAPM) analysis, which resulted in an estimated mean cost of equity for the comparison group of 9.96%.

- The 9.79% return was within the overall range for the results of the Department's DCF and TGDCF (a variation on the DCF) analyses, which ran from 8.61% to 10.14 %.

- The 9.79% return was close to the average of the return-on-equity determinations made by state utility commissions for the 11 natural gas rate cases that were resolved during the fourth quarter of 2013. That average was 9.83%.

The ALJ concurred with the Company and the Department that the cost of equity should include a 3.90% adjustment for flotation costs, which he incorporated into his recommended return of 9.79%.

E. Commission Action

1. Summary of Commission Action

The Commission respectfully declines to accept the recommendation of the Administrative Law Judge on the final cost of equity and will instead set that cost at 9.35%, the average of the Department's initial and updated DCF results.

The Commission concurs with the ALJ on the strengths of the DCF model and on the appropriateness of relying on it for ratemaking purposes in this case. The Commission accepts the Department's DCF analysis, including its contention that that analysis requires no adjustment for the generic, industry-wide, or company-specific factors for which the Company and the OAG seek adjustment. The Commission accepts the ALJ's conclusion that the cost of equity should include a flotation adjustment.

The Commission finds that the ALJ's rejection of the Department's DCF result was based on a misreading of the Department's testimony and does not support moving from the Department's DCF analysis to its CAPM analysis in any case.

Finally, while the Commission finds that the Department's cost-of-equity analysis is fundamentally sound in both theory and execution, the Commission has some concern about the disparity between the final result of its original DCF analysis (9.40%) and the final result of its updated DCF analysis (9.29%). As a precaution, it will modify the Department's recommendation and average these two results, to ensure that potentially anomalous market volatility between the

[30] ALJ's Report at ¶ 172.

two analytical periods used in the original and final analyses does not skew the rate of return downward. The final cost of equity will therefore be set at 9.35%.

These decisions are explained below.

2. The Analytical Models

The Commission concurs with the Administrative Law Judge that the best practice for determining MERC's cost of equity is to rely primarily on the DCF model and to use other models—mainly the CAPM—as reasonableness checks.[31]

In MERC's last two rate cases the Commission has rejected the Company's contention—made again in this case—that using multiple cost-of-equity models produces more trustworthy results than using one.[32] There has been no testimony or argument in this case that leads the Commission to a different conclusion. As the Commission explained in the last two MERC rate-case orders:

> First, as it did in MERC's last rate case, the Commission rejects the Company's claim that using three models to determine return on equity is superior to relying primarily on the strongest model and using others as validity checks. As the Commission explained in that case:
>
>> The Commission rejects the Company's claim that using three models to determine return on equity is inherently more accurate than relying primarily on one, with a second serving as a validity check. It is not the number of models in the record that ensures a sound decision, but the appropriateness of each model for the purpose at hand, the quality of the data selected as inputs, and the caliber of the analysis applied to the results. Using three models does produce a more detailed record, but it also multiplies the risk of inaccurate inputs and increases the number of points at which subjective judgments are required.
>>
>> In short, not all models are equally probative, and not every application of the same model is equally probative. The Commission examines the results of every model introduced into the record in every case. In this case the DCF model is the best in the record for determining return on equity.

[31] ALJ Findings 155-157.

[32] *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-10-977, Findings of Fact, Conclusions and Order (July 13, 2010); *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, and Order (June 29, 2009).

> Here, too, the Commission finds that the transparency and objectivity of the DCF model make it the strongest, most credible model, and that the most reasonable way to proceed is to use its results as a baseline and to use the results of other models to check, inform, and refine those results.
>
> As the Department and the Administrative Law Judge concluded, the DCF model calls for fewer subjective judgments than the CAPM and Risk Premium models—in fact, two of its three inputs, dividends and market equity prices, are uncontested, publicly reported facts, and the third input, projected growth rates, generally come from a limited number of recognized professional resources.
>
> . . .
>
> Further, the Company's three-model method compounds the subjectivity in each of the three models by requiring the analyst to synthesize their results, using subjective criteria. It is much more straightforward to choose the strongest model, use its results as a baseline, and use the results of the other models as additional information.[33]

Here, too, the Commission finds that the DCF model provides a more objective, transparent, and reliable means of determining the cost of equity than the other models in the record and should be used as the primary analytical tool for that purpose.

3. Market-Value/Book-Value Risk Adjustments Rejected

a) MERC's Proposed Adjustment

MERC argued that the cost of equity must be adjusted upward to compensate for the disparity between the book value at which utility assets are valued and on which regulators base authorized returns, and the market values investors typically perceive and rely on in making their investment decisions. The Company claimed that this disparity understates and under-compensates for risk by making utilities' debt ratios appear lower than they are and that a "leverage adjustment" was therefore required.

The Commission rejected that claim in MERC's last two rate cases, and the Administrative Law Judge recommended rejecting it here as well.[34] The Commission concurs; as it explained in the last MERC rate case order:

> Such an adjustment would have to rest on the erroneous assumption that investors buying utility stocks are ignorant of one of the most basic facts of utility regulation – that book value is the norm for pricing utility assets and that returns will be based on book value. Assuming that investors know this basic fact, which they must, since

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[33] *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-10-977, Findings of Fact, Conclusions and Order (July 13, 2010) at 20–21.

[34] ALJ Findings 152 and 170.

> they keep buying utility stock, the only reasonable assumption is that the market value/book value dichotomy is reflected in the stock price. The stock price, of course, is properly factored into the DCF model, making further adjustment unnecessary.[35]

b) OAG's Proposed Adjustment

The OAG argued that the DCF model yields inflated cost-of-equity figures when applied to companies with stock prices whose market-value to book-value ratios significantly exceed one.

This is the case for nearly all gas utilities, including MERC. In fact, the Company pointed out that for the past 55 years, gas utilities' average market-to-book ratio has been 1.6.[36] Similarly, the average market-to-book ratio for the companies in the Department's comparison group did not fall below 1.719 from 2003 through 2013.[37] In short, stock prices with market values significantly exceeding book values are the industry norm. The OAG essentially argued that returns on equity for gas utilities are set too high as a matter of course, resulting in excessive profits for utilities.

The Administrative Law Judge rejected this argument,[38] and the Commission concurs. As the Company and the Department pointed out, the relatively high market-to-book ratios of gas utilities' stock prices (and those of utilities generally) are mainly a function of regulators' using book value, not market value, to determine the value of their assets and the return those assets should yield. While rate-of-return regulation is intended to function as a stand-in for the discipline of the market, there are unavoidable incongruities, and this is one.

Still, investors, analysts, utilities, and regulators understand this difference and factor it into their decision-making. And, as the Department and the Company pointed out, if utilities were in fact earning excessive profits due to excessive returns on equity, there would have been a run on utility stocks, eliminating excessive profits—the utility sector is not so removed from the rest of the economy that basic economic principles do not apply.

For these reasons, the Commission rejects the OAG's argument that, in setting a cost of equity for MERC, it must adjust for the Company's market-value/book-value ratio exceeding one.

4. Company-Specific Risk Adjustments Rejected

The Company proposed upward adjustments in the cost of equity to reflect its relatively small size, significant concentration of large industrial customers, relatively high earnings variability, relatively low interest coverage, and relatively high five-year average operating ratio. The Commission concurs with the Department that none of these factors invalidate its carefully conceived and properly executed DCF analysis and none require post-analysis adjustment of its results.

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[35] *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-10-977, Findings of Fact, Conclusions, and Order (July 13, 2010) at 22.

[36] MERC Initial Brief at 21.

[37] *Id.* at 21.

[38] ALJ Finding 170.

The Department selected its comparison group of companies based on their being similarly situated and having similar investment risks, as set forth below:[39]

- All companies' main line of business is natural-gas distribution.
- All are traded on one of the stock exchanges.
- All have an S&P bond rating within the range of BBB to AA (MERC's parent company, Integrys, is rated A-).
- All receive at least 60% of their total net operating income from natural-gas distribution operations.
- All are listed on Value Line Investment Survey as of September 6, 2013, as natural gas utilities meeting the criteria set forth above.
- All have both a beta and standard deviation of past price changes that deviate by no more than one standard deviation from the mean of the companies meeting the five screens above. (Beta and standard deviation are measures of investment and financial risk, respectively.)
- All are regulated by state utility commissions.

All companies within this comparison group—and every comparison group—have individual characteristics that differ from some or all of the other companies within the group. The DCF model rests on the assumption that in a properly constituted comparison group—one whose members are reasonably similar in the measurable, generic characteristics that affect investment risk—these differences will offset one another and be neutralized by the companies' overarching similarities.

To assume otherwise undermines the comparison-group concept and the integrity of the DCF model. The DCF model relies on a macro-analysis of risk factors; inserting an abbreviated micro-analysis at the end of the process does nothing to enhance accuracy and introduces avoidable error. If micro-analysis were even possible—and that is questionable—it would have to be done for every company in the comparison group at an earlier point in the analytical process.

As the Department noted, it would be nearly impossible to isolate all the factors that might affect, positively or negatively, the individual investment risks of every company in a comparison group. A partial list of factors would include not only those suggested by the Company but each company's specific mix of customer classes, its amount of storage capacity, the locational density of its customers, and the age of its distribution facilities.[40]

Further, as the OAG noted, the Company identified only those individual characteristics that it claimed *increased* its investment risk. MERC no doubt has some individual characteristics that *reduce* its investment risk—the OAG cites its parent company's superior performance in generating internal funds, its superior interest coverage, and its superior operating revenue, as well

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[39] Department's Initial Brief at 18–19.

[40] Department Reply Brief at 9.

as Minnesota's generally favorable economic conditions.[41] These and other characteristics reducing MERC's investment risk would have to be identified, analyzed, and quantified as well.

In short, it is probably impossible—and clearly not necessary and not analytically sound—to conduct the granular analysis of all comparison companies' individual characteristics implied by MERC's claim for Company-specific adjustments to the results of DCF modeling. As it has in the Company's last two rate cases, the Commission rejects the Company's claim to those adjustments.[42]

5. The Administrative Law Judge's Recommended Cost of Equity Rejected

a) Introduction

Despite accepting the Department's DCF analysis as the best resource in the record for setting the Company's cost of equity,[43] the Administrative Law Judge declined to adopt its results. He found the results too low, on grounds that MERC had higher investment risks than the companies in the Department's DCF comparison group. He recommended adopting the Department's CAPM results instead.

The ALJ based these conclusions on the testimony of the Department's expert witness, Eilon Amit, as he explained in his report:

> Based upon his examination of 2012 common equity ratios and 2012 long-term debt ratios for companies in the NGCG[44] and MERC, Dr. Amit[45] concluded that the NGCG and MERC present similar investment risks, although "MERC appears to be somewhat riskier than NGCG."[46]
>
> . . .
>
> Moreover, as noted above, Dr. Amit's NGCG included companies whose risk profiles were lower than MERC's—presumably with easier access to capital.[47]
>
> . . .

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[41] OAG Reply Brief at 17.

[42] *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-10-977, Findings of Fact, Conclusions and Order (July 13, 2010); *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, and Order (June 29, 2009).

[43] See discussion above, under *D. The Recommendation of the Administrative Law Judge*.

[44] Natural Gas Distribution Comparison Group, the Department's comparison group.

[45] Dr. Eilon Amit, the Department's expert witness on return on equity.

[46] ALJ's Report at ¶ 112.

[47] ALJ's Report at ¶ 116.

> The DCF model is a reasonable, market-oriented approach to determine a fair ROE for MERC.
>
> Yet, because MERC's risk profile is higher than the comparison group used by the Department, in the view of the Administrative Law Judge, Dr. Amit's recommendation of 9.40 percent understates the appropriate return on equity.
>
> In the view of the Administrative Law Judge, the results of Dr. Amit's updated CAPM with flotation costs—namely, a recommended ROE [return on equity] of 9.79 percent—yields a better and more reasonable result. This higher percentage is:
>
> (a) more reflective of the investment risks MERC presents when seeking capital;
>
> (b) one basis point from MERC's updated DCF analysis, which rendered a ROE of 9.8 percent;
>
> (c) supported by Dr. Amit's ECAPM analysis, which resulted in an estimated ROE mean for the NGCG of 9.96 percent with flotation costs;
>
> (d) comfortably within the overall range for Dr. Amit's DCF and TGDCF analyses (with a low of 8.61 percent to a high of 10.14 percent, including flotation costs); and
>
> (e) close to the average ROE determinations made by state utility commissions for the eleven natural gas rate cases that were resolved during the fourth quarter of 2013—specifically, an average ROE of 9.83 percent.[48]

The Commission concludes that the ALJ's finding that MERC's risk profile is higher than that of the Department's comparison group is erroneous and based on a misreading of Dr. Amit's testimony. The Commission further concludes that substituting the Department's CAPM results for its DCF results lacks support in the record and would be an inappropriate remedy. These conclusions are explained below.

b) MERC's risk profile is not higher than the comparison group.

The entire exchange on which the ALJ based his finding of MERC's higher risk profile occurred in Dr. Amit's direct testimony and reads as follows:

> ***Q. Please summarize the results of your risk-screen analysis.***
>
> A. Both MERC and the companies in my NGCG are mostly engaged in the distribution of natural gas and are similarly rate-of-return regulated by the states in which they operate. Therefore, their business risks are somewhat similar. Regarding the specific risk measures, MERC is a subsidiary company and therefore, does not have beta, STDPC [Standard Deviation of Price

[48] ALJ's Report at ¶¶ 171–73.

> Changes], or a credit rating. Therefore, the only market-related quantitative risk measures available for comparison are the long-term debt ratios and the equity ratios.
>
> The average 2012 long-term debt ratio of NGCG[49] is 42.90 percent as compared to 47.01 percent for MERC (the long-term debt ratio for MERC is calculated excluding short-term debt from the capital structure, to make it comparable to the long-term debt ratio for NGCG), The average 2012 ratio for NGCG is 57.10 percent as compared to 52.99 percent for MERC (once again excluding short-term debt from the capital structure). Therefore, based on the only available market quantitative financial risk measures for MERC, MERC appears to be somewhat riskier than NGCG.
>
> However, both the equity and debt ratios for MERC are well inside the range of the group's +/- one standard deviation from the means, and three of the companies in NGCG have higher debt ratios than MERC.
>
> ***Q. Dr. Amit, please state your conclusion regarding the investment risks of MERC versus the investment risks of a typical company in your comparison group (NGCG).***
>
> A. Based on the only available quantitative market risk measures for MERC (debt ratio and equity ratio) and based on the fact that both MERC and the companies in my comparison group are engaged in the same line of business (natural gas distribution), and are similarly regulated by the state in which they operate, I conclude that MERC's investment risks are reasonably similar to the investment risks of the companies in my comparison group.[50]

As the full passage quoted above makes clear, Dr. Amit did not conclude that MERC's risk profile was higher than that of his comparison group. His "appears to be somewhat riskier" statement was made in the context of explaining that MERC's status as a subsidiary company complicated his analysis because the normal market-related metrics of beta, STDPC,[51] and credit rating were not available. The only market-related metrics available for MERC were equity ratio and debt ratio, which were somewhat higher than the group average.

Nevertheless, he explained, both ratios were well inside the range of the group's +/- one standard deviation from the mean, and three of the nine companies in the comparison group had *higher* debt ratios than MERC. Further, like MERC, all companies in the group were engaged in the same line of business—natural gas distribution—and all, like MERC, were rate-regulated by state public utility commissions.

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[49] Natural Gas Distribution Comparison Group, the Department's comparison group.

[50] Exhibit 200 at 12–13, Amit Direct.

[51] Standard Deviation of Price Changes.

Based on careful analysis of all these facts, Dr. Amit concluded—and contended throughout the case—that MERC's risk profile was no higher than the comparison group's. The Commission therefore does not accept the Administrative Law Judge's finding that Dr. Amit concluded that MERC's risk profile was higher than the comparison group's. Nor does it accept the finding, which is supported solely by citations to Dr. Amit's testimony, that MERC is in fact riskier than the comparison group.

Further, although the Company vigorously disputed Dr. Amit's claim that MERC's risk profile was no higher than the comparison group's, it never identified the two metrics at issue—its equity ratio or long-term debt ratio vis-à-vis those of the other companies in the comparison group—as demonstrating higher risk or requiring an upward adjustment to the cost of equity.

Instead, it offered comprehensive testimony and briefing on *other* factors it claimed merited adjustments—the book value-market value disparity common to all utility stocks, its size, its significant concentration of large industrial customers, and its relatively high earnings variability, relatively low interest coverage, and relatively high five-year average operating ratio. The Company clearly did not think the two risk factors on which the Administrative Law Judge based his upward cost-of-equity adjustment merited it.

For all these reasons, the Commission finds that MERC does not have a higher risk profile than the companies in the Department's comparison group and that no upward adjustment to the cost of equity is merited on that basis.

c) The remedy adopted by the Administrative Law Judge lacked support in the record.

Finally, had there been reason to find that the two metrics that complicated Dr. Amit's selection of his comparison group made MERC more risky than the group as a whole, substituting the results of the Department's CAPM analysis for the results of its DCF analysis would not have been the best available remedy.

It clearly would have been preferable to quantify the impact of the Company's equity ratio and long-term debt ratio and adjust the Department's recommended cost of equity on that basis. That task, of course, would have been complicated by the absence of evidence on the issue from any party. But it is anomalous to adopt the result of an analysis found to be inferior to correct a perceived flaw in a superior analysis.

Further, the corroborating factors cited in the ALJ's Report do not support adopting the Department's CAPM results. The probative value of the Department's CAPM figure being just one basis point from MERC's DCF figure is compromised by the defects found in MERC's DCF analysis, especially its upward adjustments for generic and Company-specific risk factors found not to merit adjustment.

The fact that the Department's CAPM figure fell within the ranges of reasonableness established in its DCF and TGDCF[52] analyses provides little support; those ranges encompass a broad range of numbers, from 8.61% to 10.14%, and could be used in support of a broad range of returns.

[52] Two Growth Rates DCF, used to stabilize results during periods of high market volatility.

Similarly, the fact that the CAPM figure is fairly close to the 9.96% mean in the Department's ECAPM[53] analysis is unpersuasive; that 9.96% mean is still 17 basis points higher than the return recommended by the Administrative Law Judge.

The fact that the CAPM figure was close to the average of the returns on equity granted by state commissions in rate cases during the fourth quarter of 2013 also has little probative value. Those cases yielded a wide range of returns, from 9.08% to 10.25%,[54] and some returns were significantly below the Administrative Law Judge's 9.79% recommendation. Further, those cases were decided on the basis of financial and economic data that is now outdated.[55]

And most importantly, all rate-case decisions are record-driven and based on unique facts pertaining to the utility, its customers and service area, and prevailing economic conditions. There is no way to determine which, if any, of the 11 cases in that group had significant similarities to this one.

For all these reasons, the Commission rejects the Administrative Law Judge's finding that the Department's CAPM results represent a more reasonable cost of equity than its DCF results.

6. Flotation Adjustment Accepted

The Administrative Law Judge concurred with the Company and the Department that flotation costs are properly added to the cost of equity to ensure the Company an opportunity to earn its full, authorized rate of return. He also found that the 3.9% level agreed to by those parties was just and reasonable. The Commission concurs.

It is clear that raising equity capital involves substantial costs. If these costs are not factored into the cost of equity, or an equivalent adjustment made, the amount of equity available for Company use would be overstated and its ability to earn its authorized rate of return impaired. In effect, the Company would be granted a lower rate of return than the one officially set by the Commission. A flotation cost adjustment is therefore just and reasonable.

7. Department's Recommendation Modified; Final Cost of Equity Set

The Commission finds that the Department's DCF analysis is fundamentally sound in theory and execution and is the most reliable resource in the record for setting MERC's cost of equity. The Commission accepts that analysis and its results, with the minor modification explained below.

In its initial testimony, the Department recommended a return on equity of 9.40%, based on the stock closing prices for the companies in the comparison group for the period between September 1 and September 30, 2013. In its surrebuttal testimony, the agency updated its recommended return on equity to 9.29%, based on more recent closing prices. The more recent prices were for the

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[53] Empirical CAPM, an alternative CAPM model sometimes applied to companies with betas smaller than one.

[54] Department's Initial Brief at 40.

[55] For the most part, these cases would be based on financial and economic data from 2012 and early 2013.

period between March 14 and April 14, 2014. The passage of six months' time had reduced the cost of equity by 11 basis points.

The Department's expert witness explained the importance of using current closing prices as follows:

> Since the current price per share incorporates all relevant publicly available information, non-recent historical prices should be avoided in calculating the dividend yield. However, since share prices are very volatile in the short run, it is desirable to use a period of time long enough to avoid short-term aberrations in the capital market, yet short enough to avoid using irrelevant historical information. Thus, I use the September 1, 2013 through September 30, 2013 period closing prices to calculate the dividend yield. This dividend yield is current, yet it covers a long enough period of time to avoid very short-term aberrations in the capital market.[56]

While the importance of current information is indisputable, it is also indisputable that closing prices for the 32-day period ending today would differ from those for the March 14–April 14 period on which the Department based its recommendation of 9.29%, as well as from the September 1–September 30 period on which it based its recommendation of 9.40%. And closing prices will differ to some extent for every 32-day period during which the rates being set today are in effect.

The Commission cannot set the cost of equity in real time, and routine market fluctuations will inevitably affect its accuracy throughout the period it remains embedded in rates. Still, the Commission is concerned about the outsized impact in this case of one 32-day time period. To reduce the effect of any market volatilities or idiosyncrasies that may have contributed to the disparity between the September 1–September 30, 2013 and March 14–April 14, 2014 stock prices, the Commission will average the Department's initial and updated DCF results, setting the cost of equity at 9.35%.

XIV. Capital Structure and Overall Cost of Capital

All parties agreed on the Company's capital structure and on the cost of long- and short-term debt. The Administrative Law Judge concurred in their joint recommendation, as does the Commission.

The Company, the Department, and the OAG disagreed on the cost of common equity. As explained above, the Commission has set the cost of equity at 9.35%.

The resulting overall capital structure and cost of capital are set forth below:

[56] Exhibit 200, Amit Direct at 15.

Component	Component Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	44.64	5.5606	2.4822%
Short-Term Debt	5.05	2.3487	0.1186%
Common Equity	50.31	9.35	4.7040%
Total	100.00%		7.3048%

CLASS COST OF SERVICE STUDY ISSUES

XV. Class Cost of Service Study in General

As required by rule, the Company's rate-case filing included a class cost of service study.[57]

The purpose of a class cost of service study is to determine, as accurately as possible, the costs of serving each customer class. While these costs cannot be determined with precision, it is critical that the cost study make both its underlying assumptions and the cost figures they yield as accurate and transparent as possible, because the Commission puts substantial weight on cost causation in determining what portion of the total revenue requirement each customer class should pay.

The OAG challenged three aspects of the Company's cost study: (1) its compliance with the Commission's order that it allocate income taxes on the basis of the taxable income attributable to each class, not rate base; (2) its interclass allocation of distribution-mains costs; and (3) its interclass allocation customer-service costs.[58]

Each challenge is addressed below, followed by the Commission's determination that the class cost of service study is acceptable for use as a ratemaking tool in this case.

XVI. Allocating Income Taxes

A. Introduction

In MERC's 2008 rate case, the Commission ordered the Company to change how it allocated income-tax expense among its customer classes. Previously, MERC had allocated income-tax responsibility according to each class's share of rate base. The Commission ordered MERC instead to "allocate income taxes on the basis of the taxable income attributable to each customer class."[59]

In its next rate case, MERC provided class cost of service studies that allocated income taxes both on the basis of the taxable income attributable to each customer class and on the basis of rate base.[60] The Company recommended that the Commission adopt the rate-base allocation methodology, claiming that it better allocated costs to customers based on cost causation.

[57] Minn. R. 7825.4300(C).

[58] The OAG also disagrees with MERC's allocation of its meter-reading expenses. However, the OAG stated in its exceptions to the ALJ's Report that it is no longer pursuing this issue. It merely requested that Commission update Finding 649 to correctly reflect its position. The Commission will so order.

[59] Docket No. G-007, 011/GR-08-835, Findings of Fact, Conclusions of Law, and Order (June 29, 2009).

[60] Docket No. G-007, 011/GR-10-977.

The Department agreed that under MERC's circumstances, allocating income taxes by class share of rate base would accurately reflect the cost of providing service. The Administrative Law Judge noted the parties' agreement, and the Commission adopted the ALJ's report without commenting on the income-tax-allocation issue.

B. Positions of the Parties

In the present case, MERC again allocated the Company's total income-tax expense among its customer classes in proportion to each class's share of rate base. Using algebraic formulas, MERC demonstrated that income taxes have a proportional relationship to rate base. Because of this relationship, MERC contended that income taxes should be allocated based on each class's share of rate base as determined in its class cost of service study.

The Department agreed that it was appropriate to allocate income taxes on the basis of rate base. The Department stated that, under MERC's current circumstances, this allocation would be mathematically equivalent to allocating income taxes on the basis of taxable income by class that fully and only reflects the class cost of service study.

The OAG recommended that MERC allocate income tax to customer classes based on taxable income for each class, as the Commission ordered in the 2008 rate case.

The Department responded that allocating income taxes based on each class's share of taxable income would not solely reflect the cost of providing service. Allocating income taxes based on taxable income under MERC's current rates would reflect rate-design judgments from MERC's last rate case, while using the rates proposed in the present case would reflect the Company's rate-design judgments. The Department therefore recommended against this approach.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that allocating income taxes on the basis of class percentage share of rate base was mathematically equivalent to allocating income taxes on the basis of taxable income by class that fully and only reflects the class cost of service study. The ALJ found that MERC's method was consistent with the Company's prior rate cases and the methodology used by other utilities, and produced reasonable allocations in this case.

D. Commission Action

The Commission concurs with the ALJ and accepts his findings, conclusions, and recommendation.

The goal of a class cost of service study is to allocate responsibility for a particular cost to the customer class that caused the cost to be incurred. Basing interclass income-tax allocations on taxable income from the revenues collected from each customer class necessarily departs from cost-causation principles and incorporates the policy judgments built into the rates that generated those revenues. Such policy judgments do not belong in the class cost of service study, but in the rate design decisions made in the course of the rate case.

Instead, for the purposes of allocating income-tax expense among customer classes, a class's taxable income should be based on the allocation of costs within the class cost of service study.

MERC's allocation method, using the class share of rate base determined in the class cost of service study, is consistent with cost-causation principles and is the most accurate method for allocating income-tax expense on this record.

XVII. Allocating Distribution-Main Costs

A. Introduction

An important purpose of the class cost of service study is to split the costs of the Company's distribution system—consisting primarily of its gas mains and the surface equipment used to monitor and regulate gas pressure at fixed locations—into two parts: the costs of connecting all customers to the central distribution network (customer costs) and the costs of delivering gas to customers (capacity costs).

The distinction has important rate consequences, because customer costs are allocated by class based on total customer numbers, and capacity costs are allocated by class based on total class usage. Since 89.7% of MERC customers are in the residential class, that class pays approximately 90% of customer costs. But because their per-customer usage is lower than the per-customer usage of large customers, they pay approximately 63% of capacity costs.

To determine the appropriate division between customer costs and capacity costs, the Company conducted a "zero-intercept" study. A zero-intercept study uses regression analysis to estimate the cost of a theoretical distribution system with zero-inch mains, which carries no gas and is therefore assumed to reflect only the costs of connecting customers to the system. All costs above these connection-only costs are assumed to be caused by the need to deliver gas and are classified as capacity costs. Based on its zero-intercept study, MERC determined that 68.3% of its distribution mains should be classified as customer costs and that 31.7% should be classified as capacity costs.

At the Department's request, MERC conducted three "minimum-size" studies to check the results of its zero-intercept study. The goal of a minimum-size study is similar to that of a zero-intercept study—to estimate the costs associated with simply connecting customers to the distribution system. However, rather than calculating the cost of a system with zero-inch mains, a minimum-size study calculates the cost of a system with "minimum" sized equipment—based on the size of currently or historically installed equipment or the minimum size needed to meet safety standards. A minimum-size study is easier to perform than a zero-intercept study, but it results in some capacity costs being classified as customer costs since a minimum-sized system carries some gas.

In its first two minimum-size studies, MERC used two-inch mains as its minimum installation standard. The first study classified 74.1% of the distribution system as customer-related and the remaining 25.9% as capacity-related. The second study, in which MERC also aggregated the data for two-inch and smaller mains, classified 73.2% of the distribution system as customer-related and 26.8% as capacity-related.

MERC conducted a third minimum-size study to demonstrate the results that occur when its minimum installation standards are not considered. This study classified 32.04% of the distribution system as customer-related and 67.96% as capacity-related.

B. Positions of the Parties

1. The OAG

The OAG argued that errors in MERC's zero-intercept study rendered it unreliable. First, the OAG argued that MERC's model excluded relevant variables—including number and material of fittings, number of valves, route selection, depth of installation, and geography of installation—that influence the cost of installing a main. The OAG argued that MERC's model relies solely on main diameter to determine cost, rendering it overly simplistic.

Second, the OAG objected to MERC's decision to reclassify mains with a diameter of less than two inches as two-inch mains.

Finally, the OAG argued that MERC should have built its model on project-level data rather than using data aggregated by pipe diameter and year of installation. The OAG claimed that aggregating data in this way would obscure any relationships that might exist among variables at the project level, again oversimplifying the model.

The OAG recommended that the Commission reject MERC's zero-intercept study and instead allocate distribution-main costs based on its expert's zero-intercept study, which found that 26% of the mains account should be classified as customer costs. The OAG recommended classifying a slightly greater percentage—30%—of the mains account as customer costs after reviewing zero-intercept studies by other utilities, whose average customer-cost allocation was 35.63%.

2. The Company

MERC argued that its zero-intercept study was the proper tool to classify the Company's mains and asked that the Commission approve a customer-cost/capacity-cost allocation of 68.3%/31.7%. MERC noted that the study's results were confirmed by the first two minimum-size studies and argued that the third minimum-size study was not valid because it did not account for the Company's installation practice of using pipes no smaller than two inches in diameter.

MERC maintained that, similar to a minimum-size study, a zero-intercept study must take into account the Company's current practice of installing two-inch mains. MERC stated that its practice reflects industry standards, safety measures, and the unique characteristics of the Company's service territory. MERC argued that including smaller mains installed 50 or more years ago would present an inaccurate picture of the costs caused by MERC's current customers.

Contrary to the OAG's argument, MERC asserted that the study did include appropriate variables and that some items that were not specified as unique variables, such as fittings and valves, were already included in the book values used in the study. MERC acknowledged that it might be able to retrieve additional distribution-main information but stated that it had never before been asked to do so and argued that the extra cost would not be justified.

Finally, MERC argued that aggregating and averaging mains data on a system-wide basis produces the most accurate representation of MERC's entire distribution system. MERC stated that the National Association of Regulatory Utility Commissioners' (NARUC's) Electric Utility Cost Allocation Manual, which is also used by gas utilities, recommends using average installed book cost to perform a zero-intercept study.

3. The Department

In light of the large difference between MERC's and the OAG's zero-intercept studies and the questions the OAG raised about MERC's regression analysis, the Department asked MERC to classify its mains using the minimum-size method. Because of the similarity in the results of MERC's zero-intercept and minimum-size analyses, and because the Department found MERC's use of a two-inch minimum main reasonable, the Department recommended that the Commission accept MERC's assignment of distribution-main costs.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that MERC's zero-intercept study was based upon data that was available and complete. He found that the Company's assumptions, specifications, and statistical techniques were similar to, and consistent with, those used by Integrys's other subsidiaries.

The ALJ concluded that the OAG's critiques of MERC's methodology were not well taken, finding that neither MERC nor other utilities in Minnesota have been required to maintain the types of historical data urged by the OAG for class cost of service studies. He further found that only one Minnesota utility maintains the type of data that the OAG regards as "project level" detail. The ALJ found that some of the data points that the OAG would include in the analysis—such as the length of the distribution main, or the reason why the pipe was installed—contribute little to the development of a "hypothetical zero-load or zero-sized distribution main on MERC's entire system."

With respect to the reasonableness of the study results, the Administrative Law Judge concluded that a proper zero-intercept analysis should reflect the costs of actual steel distribution mains and industry standards for installation of such mains. The ALJ concluded that MERC's minimum-size analysis demonstrates that at least 73 percent of the distribution mains would be classified as customer costs and 27 percent as capacity costs.

D. Commission Action

The Commission agrees with and accepts the Administrative Law Judge's findings on this issue. However, the Commission does not agree with the ALJ's apparent conclusion that MERC's distribution mains should be classified using the results of MERC's minimum-size studies. For the reasons discussed below, the Commission concludes that MERC's distribution mains should be classified using the Company's zero-intercept study.

First, the Commission concurs with the ALJ's analysis finding MERC's zero-intercept study reasonable: MERC conducted its study based on data that was available, complete, and reflective of its current circumstances. Second, MERC's first two minimum-size studies confirmed the zero-intercept study's result. Specifically, they classified a slightly larger percentage of the mains account as customer costs, a result which is consistent with the tendency of a minimum-size study to designate more costs as customer costs.[61]

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[61] The third minimum-size study does not reflect MERC's minimum installation standards and therefore is not useful for allocating distribution-main costs.

Based on this confirmation, the Department recommended that the Commission accept MERC's assignment of distribution-main costs based on its zero-intercept study. The Commission agrees and finds that 68.3 percent of MERC's distribution mains were classified as customer costs and 31.7 percent as demand costs.

While MERC's zero-intercept study is reasonable under the circumstances of this case, the OAG has highlighted several areas for potential improvement. The Commission will require MERC, in its next rate case, to take the following measures to improve its analysis:

- collect data on additional variables that impact the unit cost of mains installation;
- avoid aggregating or averaging data and use data at the finest level reasonable;
- check ordinary-least-squares regression assumptions and correct for violations; and
- make any future zero-intercept analysis more transparent to ensure that MERC's work can be easily replicated.

The minimum-size studies MERC conducted in this case have proven valuable as a way to check the results of the zero-intercept study. Therefore, to facilitate review of MERC's zero-intercept study in the Company's next rate case, the Commission will require that the MERC submit two class cost of service studies, one based on the zero-intercept method and the other on the minimum-size method.

Finally, in its exceptions to the ALJ's Report, the OAG argued that the ALJ's findings do not accurately describe the difference between the minimum-size method and the zero-intercept method or the fact that the minimum-size method classifies some capacity costs as customer costs. The Commission will adopt the OAG's proposed modifications to Finding 631 to provide a more complete explanation of the differences between the minimum-size method and the zero-intercept method.

XVIII. Customer Records and Collection Expense, FERC Account 903

A. Introduction

MERC records costs related to customer applications, contracts, orders, credit applications billing and accounting, collections, and complaints in Federal Energy Regulatory Commission (FERC) Account 903.

To arrive at an interclass allocation of Account 903, MERC first assigned the cost of administering the Company's transportation program to its transportation customers. The remaining amounts were primarily the costs of retaining Vertex, an external service provider to whom MERC has delegated its customer-service functions. Because Vertex charges MERC a flat per-customer rate for its services, MERC allocated the remaining FERC Account 903 costs based on the number of customers in each class.

B. Positions of the Parties

The OAG argued that Account 903 costs should be assigned using a weighted allocator because larger customers have more complex accounts that cost more to administer. The OAG argued that Vertex may have spread the extra cost of serving large commercial customers among MERC's residential customers by pricing all customers equally. The OAG also asserted that MERC's method deviates from NARUC's natural-gas rate design manual and that two other Minnesota utilities—Xcel Energy and CenterPoint Energy—use weighted allocators to assign customer-service costs.

MERC responded that its transportation customers were the only class with significantly higher account-administration costs. MERC argued that neither the NARUC manual nor Xcel and CenterPoint's practices are relevant because the NARUC manual was published before utilities began to outsource their customer-service functions and because there is no evidence that Xcel and CenterPoint outsource their customer service functions as MERC does.

The Department accepted MERC's claim that the only significant cost differences between customer classes were those attributable to administering MERC's transportation program. The Department concluded that it was appropriate to allocate costs differently to transportation customers and agreed with MERC that no further weighting was needed since Vertex charges a flat rate per customer.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that MERC's allocation of customer records and collection expenses followed directly from its actual, arms-length transaction with Vertex and was reasonable.

D. Commission Action

The Commission concurs with the Administrative Law Judge and accepts his findings, conclusions, and recommendations. MERC has shown that, besides the transportation class, each of its customers causes the same amount of customer costs. The Company's cost allocation of Account 903 is reasonable and supported by substantial evidence in the record.

XIX. Class Cost of Service Study Accepted

The ALJ found that MERC's class cost of service study "fully and correctly demonstrates the embedded fixed costs of residential service."[62] He recommended that the Commission adopt the class cost of service study and use it as a basis for revenue apportionment and rate design.

The Commission agrees in part. A class cost of service study is not precise but can be a useful tool for setting rates. In this case, MERC's class cost of service study, while not precise, presents an essentially accurate overall picture of the fixed costs of residential service. The Commission will therefore accept it as a useful tool for the purpose of setting rates, and will strike the ALJ's Finding 650 to maintain consistency with the Commission's decision.

[62] Finding 650.

RATE DESIGN ISSUES

XX. Interclass Revenue Apportionment

A. Introduction

In every rate case the new revenue requirement must be apportioned among the customer classes, raising the issue of whether to adjust the interclass revenue responsibility built into the existing rate structure.

In this case, the Company and the Department proposed to fine-tune the existing interclass revenue apportionment by shifting slightly more revenue responsibility to certain customer classes (residential, small commercial and industrial (C&I), and large-volume transport) whose rates do not fully recover the costs calculated under the Company's class cost of service study. The residential and small C&I classes would pay, respectively, approximately 92% and 100% of the costs of serving them. This proposal translates to a 5% and 5.5% rate increase for the two classes, compared to the 4.1% overall rate increase sought by the Company.[63]

MERC and the Department also agreed to minimize rate increases for the super-large-volume and flex customer classes, since these customers are very cost-sensitive and are able to bypass MERC's system, a result which would harm MERC's other customers.

B. Positions of the Parties

1. The Company and the Department

MERC argued that its proposed allocations are consistent with its class cost of service study, which demonstrates that the current allocations for the residential and small C&I classes are below their actual cost of service.

In reviewing the Company's proposed revenue apportionment, the Department considered (1) whether the current rates resulted in interclass subsidies, (2) whether the proposed increases for residential and small C&I classes would result in rate shock, and (3) whether the proposed rates for super-large-volume and flex customers remain competitive with other fuel options available to those customers. The Department concluded that MERC's proposed revenue apportionment addressed concerns about large customers leaving MERC's system.

2. The OAG

The OAG recommended that there be no change to MERC's existing revenue apportionment. The OAG argued that the class cost of service study overstated the costs caused by the residential and small C&I classes and that residential customers are very close to paying 100% of their costs under the current rates. The OAG also argued that several non-cost factors, such as residential customers' limited ability to pay, supported using MERC's existing apportionment.

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[63] *See* Surrebuttal Testimony of Susan Pierce, Schedule 1 (May 7, 2014).

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the revenue allocation recommended by the Company and the Department was reasonable and should be adopted. He recommended that their revenue apportionment be used to determine the final rate design after the Commission has determined MERC's final revenue requirement.

D. Commission Action

The Commission concurs with the Administrative Law Judge and will adopt the proposed revenue allocation agreed upon by MERC and the Department, as recommended by the ALJ. MERC and the Department's proposal appropriately balances cost and non-cost factors. Specifically, it brings residential, small C&I, and large-volume allocations closer to cost, maintains competitive rates for super-large-volume and flex customers, and avoids the likelihood of rate shock.

XXI. Customer Charges

A. Introduction

The customer charge is a fixed monthly charge assessed without regard to usage levels. It is designed to help recover fixed customer-related costs such as the cost of meters, service lines, meter reading, and billing.

MERC's current monthly customer charges are as follows:

Customer Class	Current Charge
Residential	$8.50
Small Vol. C&I	$14.50
Large Vol. C&I	$35.00
Small Vol. Interruptible	$150.00
Large Vol. Interruptible	$175.00
Super Lg. Volume	$300.00

MERC's class cost of service study found that the fixed costs of serving its customers exceeded the current monthly customer charges, in some cases by a substantial margin. For example, the study found that the fixed monthly cost of serving a residential customer was $25.53. For a small C&I customer, the cost was $27.85 per month.

B. Positions of the Parties

1. The Company

MERC initially proposed to increase the residential customer charge to $11.00 per month. MERC argued that the increase would reduce intraclass subsidies, result in less variability between winter and summer bills, provide a more accurate price signal to customers, and incrementally stabilize MERC's cash flow. The Company later accepted the Department's recommendation that this charge be increased to only $9.50 per month

MERC also proposed the following customer-charge increases for its non-residential customer classes:

Customer Class	Proposed Charge
Small Vol. C&I	$18.00
Large Vol. C&I	$45.00
Small Vol. Interruptible	$160.00
Large Vol. Interruptible	$185.00
Super Lg. Volume	$350.00

2. The Department

The Department recommended increasing the residential customer charge to only $9.50 per month. The Department argued that increasing the residential charge to $9.50 would move it closer to cost and reduce intra-class subsidies without causing rate shock. The Department further asserted that a customer charge of $9.50 is consistent with other Minnesota utilities' residential customer charges.[64]

The Department agreed with MERC's proposed customer charges for its non-residential customer classes.

3. The OAG

The OAG opposed increasing the residential and small C&I customer charges. The OAG argued that keeping the customer charge low would send ratepayers a stronger price signal to reduce energy use, fulfilling the Commission's statutory duty to set rates that encourage energy conservation to the "maximum reasonable extent."[65] By contrast, the OAG asserted, increasing the customer charge would tend to confuse and alienate ratepayers and burden low-income households.

C. The Recommendation of the Administrative Law Judge

The ALJ's customer-charge-related findings and conclusions appear in paragraphs 661–77 of the report. The ALJ recommended that the Commission approve MERC's proposal to increase the residential customer charge to $9.50 per month. The ALJ further found that MERC's proposed

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[64] *See, e.g.*, *In the Matter of an Application by CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-13-316, Findings of Fact, Conclusions, and Order at 51 (June 9, 2014) (ordering a monthly residential customer charge of $9.50).

[65] Minn. Stat. § 216B.03.

increase to the customer charges for larger customers was supported by the class cost of service study and recommended that the Commission adopt the proposed charges.

D. Commission Action

Having reviewed the record, including the oral and written arguments of the parties and members of the public, the Commission concludes that a $9.50 monthly residential customer charge is appropriate and will adopt the ALJ's recommendation. The Commission also agrees that MERC's proposed customer charges for its non-residential classes are warranted, including an $18.00 charge for the small C&I class. Accordingly, the Commission will adopt the ALJ's recommendation to approve those charges.

Moving the customer charges closer to the actual cost of service will promote rate-design equity by minimizing intraclass subsidies. Intraclass subsidies arise when certain customers within a class pay more than the cost to serve them, subsidizing other customers within the same class who pay less than their cost of service.

For example, if the residential customer charge does not recover the full cost of connecting and keeping a residential customer on the system, then those fixed costs will be recovered in part through the volumetric, per-therm charge. As a result, high-use residential customers will pay not only for their own fixed costs and energy costs, but also for part of lower-use residential customers' fixed costs.

The Commission is sensitive to the concern that a sudden, large increase in the customer charge could lead to rate shock or remove some incentive to conserve energy. However, the Commission concludes that the modest increases agreed to by MERC and the Department and recommended by the ALJ will minimize intraclass subsidies without inducing rate shock or discouraging conservation.

FINANCIAL SCHEDULES AND COMPLIANCE

XXII. Overall Financial Schedules

A. Gross Revenue Deficiency

Revenue Deficiency - Minnesota Jurisdiction
Test Year Ending December 31, 2014

Description		MERC - MN
Average Rate Base	$	189,725,213
Rate of Return		7.3048%
Required Operating Income	$	13,859,047
Operating Income	$	9,410,236
Income Deficiency	$	4,448,811
Gross Revenue Conversion Factor		1.7040
Gross Revenue Deficiency	$	7,580,774

B. Rate Base Summary

Rate Base Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2014

Description	MERC-MN
PLANT IN SERVICE	
Energy	$ 999,429
Transmission	$ 6,833,452
Distribution	$ 368,477,466
Customer	$ 5,206,114
Plant Adjustment	$ (35,745)
Total Plant In Service	$ 381,480,716
RESERVE FOR DEPRECIATION	
Energy	$ 326,488
Transmission	$ 3,072,997
Distribution	$ 164,797,536
Customer	$ 1,700,703
Plant Adjustment	$ -
Total Reserve For Depreciation	$ 169,897,724
NET PLANT IN SERVICE	
Energy	$ 672,941
Transmission	$ 3,760,455
Distribution	$ 203,679,930
Customer	$ 3,505,411
Plant Adjustment	$ (35,745)
Total Net Plant In Service	$ 211,582,992
Construction Work in Progress	$ -
LESS: Customer Advances	$ -
LESS: Accumulated Deferred Income Taxes	$ 36,631,519
Working Capital:	
Cash Working Capital	$ (3,759,016)
Deferred Taxes Other than Plant	$ 1,694,186
Non-Utility Adjustment	$ (1,530,328)
Materials and Supplies	$ 279,572
Gas Storage Inventory	$ 11,041,166
Regulatory Assets/Liabilities	$ 7,048,160
Total Working Capital	$ 14,773,740
TOTAL AVERAGE RATE BASE	$ 189,725,213

C. Operating Income Summary

Operating Income Summary - Minnesota Jurisdiction
Test Year Ending December 31, 2014

Description	MERC-MN	
UTILITY OPERATING REVENUES		
Retail Revenue	$	259,482,876
Late Payment Revenue	$	525,000
Other Operating Revenue	$	285,963
Total Operating Revenues	$	260,293,839
UTILITY EXPENSES		
Purchased Cost of Gas	$	173,742,607
Other Production	$	10,636
Gas Supply	$	704,365
Transmission	$	94,181
Distribution	$	17,729,619
Customer Accounting	$	11,149,619
Customer Service & Information	$	927,914
Administrative & General	$	15,106,467
Total Operating Expenses	$	219,465,408
Amortizations	$	10,121,935
Depreciation	$	9,347,278
Taxes Other than Income Taxes	$	8,777,496
Other Interest Expense	$	935
Total Depreciation & Other Taxes	$	28,247,644
Federal Income Tax	$	2,907,547
State Income Tax (MN & MI)	$	33,113
Interest Synch	$	229,891
Total Income Taxes	$	3,170,551
Total Expenses	$	250,883,603
Net Income	$	9,410,236

XXIII. Compliance Filing Required

The Commission will require the Company to make a compliance filing within 30 days of the date of this order showing the final rate effects of the decisions made here and proposing a plan for refunding the difference between the amounts it collected in interim rates and the amounts it is authorized to collect in final rates. The Commission will establish a brief comment period to give interested persons a chance to review and comment on that filing.

ORDER

1. Minnesota Energy Resources is entitled to increase Minnesota jurisdictional revenues by $7,580,774 to produce jurisdictional total gross revenues of $267,874,613 for the test year ending December 31, 2014.

2. The Commission accepts, adopts, and incorporates the findings, conclusions, and recommendations of the Administrative Law Judge to the extent that they are consistent with the decisions set forth herein.

3. The Commission adopts the recommendation of the Administrative Law Judge and approves the continuation of the farm tap inspection program, clarifying as follows.

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

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

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

4. The Commission approves total test-year incentive-compensation costs of $1,231,630. MERC shall refund any incentive-compensation costs included in the test-year revenue requirement that are not paid out in a particular year. Refunds shall be based on the incentive compensation and customer counts approved in this docket.

5. MERC shall file a tariff incorporating the reconciliation service conditions and requirements reflected in the Administrative Law Judge's Report ¶ 545.

6. The Commission modifies finding 610 of the Administrative Law Judge's Report as set forth below:

   > 610. As noted above, MERC agreed to credit the CIP tracker inclusive of carrying charges for the under-recovery of CIP charges from Northshore. The credit would be allocated between ~~to~~ MERC's Consolidated CIP Tracker ~~because~~ and MERC- PNG's

> CIP tracker based on the period Northshore should have been charged ~~is projected to be reduced to a zero balance by the end of November 2014~~.

7. MERC shall credit the CIP tracker for the CCRC and CCRA amounts that were not collected from MERC customer Northshore Mining Company from July 2006 through December 2013, before Northshore's CIP exemption became effective on January 1, 2014. The Company shall add a one-time carrying charge at its approved overall rate of return and shall report on the funding of the uncollected CIP amounts in its final compliance filing in this case.

8. The Commission authorizes MERC to apply a carrying charge at the overall rate of return set in this case to its CIP tracker account, pending further consideration of carrying-charge issues in its pending annual CIP tracker filing.

9. The Commission declines to adopt ALJ Findings 580–82. MERC shall instead collect all of its test-year CIP expenses through the CCRC with the CCRC being set at $0.02448 and $0.00000 being added to the CCRA at the time of final rate implementation. MERC shall continue its current CCRC calculation methodology by including the CCRC factor in its base distribution rate and maintain its CCRA factor in its current format.

10. In its final rates compliance, MERC shall update its CCRC factor to reflect the Department's recommended 2014 CIP expense level of $9,396,422 and shall correct its CIP applicable volumes to the Department's recommended level.

11. MERC shall debit or credit its CIP tracker account to reflect any under-recovery or over-recovery of CIP costs during the interim-rates period.

12. MERC shall review its CIP billing process and make a compliance filing in this docket reporting its findings.

13. MERC shall include, in future CIP tracker-account filings, annual compliance filings documenting that its CIP-exempt customers have been properly identified and are being properly billed.

14. In future rate cases, MERC shall meet with Department and Commission staff prior to making its initial filing to discuss CIP issues and their presentation in the filing.

15. The Commission amends ALJ Findings 437, 439, and 442 as set forth below:

> 437. While MERC asserted that reliance upon the recent history of rate filings was not appropriate in this instance, it argued that if the Department's recommendation was adopted still other adjustments would be required. Specifically: (a) debiting the unamortized rate case balance of $257,985 on an annualized basis, and crediting amortization expense for the same amount; (b) use of a normalized level of rate case costs in test year expenses for accounting purposes, but one that is not an asset in rate base for ratemaking purposes such that the Company earns a return on this

item; (c) a corresponding removal of $541,188 before allocation to Minnesota in deferred taxes from rate base; and (d) allocating only $540,106, which is the associated "Minnesota jurisdiction" share of these expenses.

439. The OAG-AUD agreed with the Department's recommendation and MERC agreed with this adjustment.

442. The Administrative Law Judge finds that a two-year amortization period is appropriate in this case. However, in the event that the Commission concludes that a three-year amortization period is more appropriate, the ALJ further recommends that the unamortized rate ~~base~~case balance of $257,985 be debited on an annualized ~~annual~~ basis and amortization expenses credited for the same amount.

16. The Company shall track rate-case expense recoveries exceeding the authorized test-year expense, for possible crediting against the revenue requirement in the next rate case.

17. MERC shall take the following actions in regard to its pending property-tax litigation:

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

b. Remit any refunds due to ratepayers with interest;

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

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

18. The Commission amends ALJ Findings 489 and 490 as set forth below:

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

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

19. MERC shall remove IBS customer-relations test-year expense of $322,226 plus $29,070 for depreciation and return on cross charges and instead defer its actual IBS customer-relations expense plus actual depreciation and return on cross charges as a regulatory asset with deferred accounting treatment, with the following conditions:

a. The ICE 2016 project expenses shall not be included in rate base as the project is not used and useful at this time; MERC did not include the expenses as construction work in progress.

b. Any discussion of amortization period shall be resolved during MERC's next rate case.

c. The deferred expenses shall be subject to a reasonableness review in MERC's next rate case.

20. The Commission amends ALJ Finding 276 as follows:

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

21. MERC shall use a five-year historical average of discount rates to calculate test-year post-retirement medical and life-insurance expense.

22. The Commission modifies ALJ Finding 209 as follows:

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

23. The Commission modifies ALJ Finding 254 as follows:

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

24. The Commission opens a generic inquiry into how the discount rate should be derived and applied in calculating future pension expenses for setting rates in Minnesota.

25. The Commission modifies ALJ Findings 160–62 as follows:

> 160. Application of the ECAPM analysis resulted in an estimated ROE mean for the NGCG of 9.76 ~~9.96~~ percent with flotation costs.
>
> 161. In Dr. Amit's Direct Testimony, ~~T~~the ECAPM's ROE was appreciably higher than Dr. Amit's CAPM's ROE and somewhat close to the mean of his DCF's ROE for the NGCG.

162. In his Direct Testimony, Dr. Amit's CAPM and ECAPM results for the NGCG lie within the range of Dr. Amit's DCF/TGDCF estimated ROEs—specifically, between 8.61 percent and 10.14 percent.

26. The Commission modifies ALJ Finding 112 as follows:

112. Based upon his examination of 2012 common equity ratios and 2012 long-term debt ratios for companies in the NGCG and MERC, Dr. Amit concluded that the NGCG and MERC present similar investment risks~~, although "MERC appears to be somewhat riskier than NGCG."~~.

27. The Commission modifies ALJ Finding 172 as follows:

172. Because MERC's risk profile is similar to the NCGC's risk profile, Dr. Amit's recommendation of 9.29 percent with flotation costs presents an appropriate return on equity. ~~Yet, because MERC's risk profile is higher than the comparison group used by the Department, in the view of the Administrative Law Judge, Dr. Amit's recommendation of 9.10 percent understates the appropriate return on equity.~~

28. The Commission strikes ALJ Finding 173 and modifies finding 174 as follows:

174. Based upon the records in these proceedings, the average of the Department's initial and updated DCF ROE result of 9.35 percent with flotation costs ~~a return on equity for MERC of 9.79 percent~~ is the most reasonable and appropriate result for MERC's cost of equity. The Commission averages the Department's initial and updated DCF results to reduce the effect of any anomalous market volatilities or other idiosyncrasies that may have contributed to the disparity between the September 1–September 30, 2013 and March 14–April 14, 2014 stock prices on which the Department based its recommended return on equity.

29. The Commission modifies Finding 631 as follows:

631. The minimum size method serves a similar, but distinct, purpose from the zero-intercept method. The zero-intercept method attempts to calculate a no load distribution system by analyzing the cost of a zero-diameter pipe that connects a customer to the system but carries no gas. In contrast, the minimum size method attempts to calculate the cost of a system that does carry load by calculating the cost of the "minimum" sized equipment. ~~While serving the same purpose as a zero-intercept method study, a~~The minimum size method study has an advantage: It does not rely upon regression analysis for its results, and is therefore easier to conduct. Instead, an analyst needs to consider whether the study should utilize the size of

> the equipment that is currently installed, historically installed, or the minimum size needed to meet safety standards. <u>Additional criteria could include when the equipment was installed and whether the equipment is installed throughout the entire system or only in limited locations. While the minimum size method has the advantage of being easier than the zero-intercept method, it can also be less accurate because it calculates the cost of a distribution system that includes gas. By including load in its calculation, the minimum size method classifies some capacity costs as customer costs. While the zero-intercept method is more complex because it requires a regression, it more accurately calculates the customer costs because it estimates the cost of a system with no load.</u>

30. The Commission modifies ALJ Finding 649 as follows:

> 649. The Department~~, OAG-AUD~~ and MERC agree on MERC's allocation of Account 902: Meter Reading Expense.

31. The Commission strikes ALJ Finding 650.

32. MERC shall take the following actions in preparing future class cost of service studies:

    a. collect data on additional variables that impact the unit cost of mains installation;

    b. avoid aggregating or averaging data and use data at the finest level reasonable;

    c. check ordinary-least-squares regression assumptions and correct for violations; and

    d. make any future zero-intercept analysis more transparent to ensure that MERC's work can be easily replicated.

33. MERC shall submit two class cost of service studies in its next rate case, one based on the zero-intercept method and the other on the minimum-size method.

34. The Company shall work with the Department to address and resolve concerns regarding Joint Rate Service identified in Section III of this order and shall make a compliance filing reporting on those efforts within 90 days of the date of this order.

35. The Commission makes the following typographical corrections to the ALJ's Report:

    a. Footnote 181 is changed to "~~*Id.* at 5.~~ <u>Ex. 212 at 11 (L. Otis Direct).</u>"

    b. Footnote 182 is changed to "~~Ex. 212 at 10–11 (L. Otis Direct).~~ <u>*Id.* at 11–12.</u>"

    c. Footnote 188 is changed to "~~*Id.* at LBO-11.~~ <u>*Id.* at 27.</u>"

    d. Footnote 190 is changed to "Ex. 212 at LBO-~~11~~ <u>12</u> (L. Otis Direct)."

    e. Footnote 191 is changed to "Ex. 212 at 28–29, 32 and Schedule (LBO-~~11~~ <u>12</u>) (L. Otis Direct)."

f. Footnote 195 is changed to "*Id.* at 5–6; Ex. 39 at 8 (H. John Rebuttal)."

g. Footnote 209 is changed to "Ex. 26 at 4 (C. Hans Rebuttal); Ex. 217 at ~~29–~~30, 34 (M. St. Pierre Direct)."

h. Footnote 211 is changed to "Ex. ~~217~~ 219 at 7 (M. St. Pierre Surrebuttal)."

i. Footnote 223 is changed to "Ex. 217 at ~~30~~ 29 (M. St. Pierre Direct)."

j. Footnote 224 is changed to "Ex. 217 at 30 (M. St. Pierre Direct). ~~*Id.*~~"

k. Footnote 234 is changed to "*Id.*; Ex. 219 at ~~n. 7~~ 26 (M. St. Pierre Surrebuttal); Ex. 27 at 8–9 (C. Hans Rebuttal)."

l. Footnote 236 is changed to "Ex. 217 at ~~30~~ 26–28 (M. St. Pierre Direct)."

m. Footnote 247 is changed to "Ex. ~~217~~ 219 at ~~31–32~~ 28 (M. St. Pierre Surrebuttal)."

n. Footnote 253 is changed to "~~*Id.* at 1 and Schedule CMH-1.~~ Ex. 219 at 32."

o. Footnote 656 is changed to "Ex. 203 at ~~13~~ 16 (S. Peirce Direct)."

p. Footnote 674 is changed to "Ex. ~~40~~ 42 at 7–8 (G. Walters ~~Direct~~ Rebuttal)."

36. In the initial filing in its next rate case, the Company shall provide a schedule showing the test year monthly depreciation expense calculations and shall show by FERC account the average monthly plant balance, depreciation rates used, monthly depreciation expense, and totals.

37. In the initial filing in its next rate case, MERC shall include a detailed breakdown of all deferred costs relating to development of Integrys' customer-relations service, Integrys Customer Experience.

38. In the initial filings of future rate cases MERC shall continue to address the three Commission concerns referred to in its March 31, 1995 order regarding service-extension requirements and shall continue to address the six questions listed in that order.

39. In the initial filings of future rate cases MEC shall continue to provide the data on winter construction charges required in earlier orders in dockets 07-1188 and 08-835.

40. In the initial filings of future rate cases MERC shall provide a schedule that reconciles the expenses in the cash working capital to the expenses in MERC's test-year Income Statement and shall base its cash-working-capital schedule on number of days rather than percentages.

41. In the initial filings of future rate cases, MERC shall provide direct testimony explaining all large differences between base-year and test-year rate base, other income, and expense data.

42. In the initial filing in future rate cases, the Company shall include the following :

a. A summary spreadsheet that links together the Company's test-year sales and revenue estimates, its CCOSS, and its rate-design schedules;

b. A spreadsheet that fully links together all raw data, to the most detailed information available and in a format that enables the full replication of MERC's process, that the Company uses to calculate the input data it uses in its test-year sales analysis;

c. A bridging schedule that fully links together old and new billing systems, and demonstrates that there is no difference between the two billing systems, in the event the Company updates, modifies, or changes its billing system;

d. Any, and all, data used for its sales forecast 30 days in advance of its next general rate case; and

e. Detailed information sufficient to allow for replication of any and all Company-derived forecast variables.

43. In future rate cases, MERC shall change the CCRC rate at the beginning of the interim rates period and again at implementation of final rates.

44. In future rate-case filings, MERC shall meet the reporting requirements of Minn. Stat. § 216B.16, subd. 17, for all travel and entertainment expenses, including expenses related to employees working for MERC affiliates.

45. In future rate-case filings, MERC shall allocate any costs not specific to Minnesota based on the allocation factor MERC files in its direct testimony and identify which costs have been allocated.

46. Within 30 days of the date of this order, the Company shall make a compliance including the following items:

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

1. Breakdown of Total Operating Revenues by type;

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

a) Total revenue by customer class;

b) Total number of customers, the customer charge, and total customer-charge revenue by customer class; and

c) For each customer class, the total number of commodity- and demand-related billing units, the per-unit commodity and demand cost of gas, the non-gas margin, and the total commodity- and demand- related sales revenues.

b. Revised tariff sheets incorporating authorized rate-design decisions.

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

d. A revised base cost of gas, supporting schedules, and revised fuel-adjustment tariffs to be in effect on the date final rates are implemented.

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

f. A schedule, together with all supporting calculations, detailing the CIP tracker balance, month by month, from the beginning of interim rates; the revenues (the CCRC and CIP Adjustment Factor) and costs recorded during the period of interim rates; and the CIP tracker balance at the time final rates become effective.

g. Because final authorized rates are lower than interim rates, a proposal to make refunds of interim rates, including interest, to affected customers.

Persons wishing to comment on the compliance filing(s) shall do so within 30 days of the date it is filed. Comments are not invited on the proposed customer notice.

47. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Burl W. Haar
Executive Secretary

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