BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota

ISSUE DATE: October 31, 2016

DOCKET NO. G-011/GR-15-736

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

Contents

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota

ISSUE DATE: October 31, 2016

DOCKET NO. G-011/GR-15-736

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

PROCEDURAL HISTORY

I. Initial Filings and Orders

On September 30, 2015, Minnesota Energy Resources Corporation (MERC or the Company) filed this general rate case. The Company asked to increase Minnesota retail natural gas rates by some $14,800,000, or approximately 5.47%, per year. 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 for the period during which interim rates would be in effect; that petition was granted by order dated November 30, 2015.[1]

Also on November 30, 2015, 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 time period for deciding the case;
- A notice of 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.

[1] *In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a New Base Cost of Gas to Coincide with Implementation of Interim Rates*, Docket No. G-011/M-15-748, Order Setting New Base Cost of Gas and Requiring Further Filings (November 30, 2015).

II. The Parties and Their Representatives

The following parties appeared in this case:

- Minnesota Energy Resources Corporation, represented by Elizabeth M. Brama and Kristin M. Stastny, Briggs and Morgan, P.A.

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

- Office of the Minnesota Attorney General—Residential Utilities and Antitrust Division (OAG), represented by Ian Dobson and Joseph C. Meyer, Assistant Attorneys General.

- Constellation NewEnergy—Gas Division, LLC (Constellation), represented by Richard J. Savelkoul, Martin & Squires, P.A.

- Hibbing Taconite Company, ArcelorMittal USA's Minorca Mine, Northshore Mining Company, United Taconite, LLC, the Minntac and Keetac Mines of United States Steel Corporation, and USG Interiors, Inc., represented by Andrew P. Moratzka and Emma J. Fazio, Stoel Rives LLP (collectively, "Super Large Gas Intervenors").

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Jeanne M. Cochran to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the evidentiary hearing. The ALJ held an evidentiary hearing in Saint Paul on May 23–24, 2016. After the hearing the parties filed initial briefs, reply briefs, and proposed findings of fact.

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

- Cloquet Chamber of Commerce, Cloquet—March 28, 2016
- Rochester City Hall, Rochester—March 29, 2016
- Albert Lea City Offices, Albert Lea—March 29, 2016
- Dakota County Technical College, Rosemount—March 30, 2016

IV. Public Comments

The Administrative Law Judge held four public hearings. Representatives of the Company, the Department, the Office of the Attorney General, and the Commission attended.

Approximately 20 members of the public attended these hearings, and 12 spoke. Over 40 members of the public filed written comments; the vast majority were residential customers. The Administrative Law Judge categorized and summarized the public comments in a nine-page attachment to her report.

Nearly all commenting members of the public either opposed the rate increase entirely or argued that it was too high. The objections raised most frequently were that the increase would cause hardship for low-income households, that the amount of the increase exceeded current inflation rates and the latest Social Security cost-of-living adjustment, and that lower natural gas prices should translate into lower utility bills.

All public comments are filed in the case record. Written comments are labeled "Public Comment," and oral comments appear in the public-hearing transcripts filed by the court reporter.

V. Proceedings Before the Commission

On August 19, 2016, the Administrative Law Judge filed her Findings of Fact, Conclusions of Law, and Recommendation (the ALJ's Report). The following parties filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700: the Company, the Department, the OAG, and Constellation.

On September 22 and 29, 2016, the Commission heard oral argument from and asked questions of the parties. On September 29, 2016, 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.

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

[3] *In re Interstate Power Co.*, 574 N.W.2d 408, 411 (Minn. 1998).

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; (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]

---

[4] *In re N. States Power Co.*, 416 N.W.2d 719, 722–23 (Minn. 1987) (citation omitted).

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

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 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. "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. Rate Case Overview

The Company's initial filing sought an annual rate increase of $14,846,380. The Company stated that the need for the increase was driven mainly by increased capital costs for system expansion in the Rochester area, infrastructure acquisition in the Albert Lea area, and general construction throughout the system to serve new customers.[8] A secondary driver identified by the Company was a series of increases in specific operational costs, including costs associated with its new customer-service system, employee compensation, and property taxes.

In the course of evidentiary development, many financial issues were resolved, and all issues relating to phase II of the Rochester expansion project were moved to a fast-track, separate proceeding,[9] reducing the Company's rate-increase request to $9,966,944. The cost of capital—specifically, the cost of equity—remained contested, as did several rate-design and class-cost-of-service issues.

---

[7] *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. App. 1989) (citation omitted) (quoting *In re N. States Power Co.*, 416 N.W.2d at 722).

[8] Ex. 13, at 7–8 (Kult Direct).

[9] *In the Matter of the Application of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for Its Rochester Natural Gas Extension Project*, Docket No. G-011/M-15-895, Notice of and Order for Hearing (February 8, 2016).

The Company used a projected, calendar-year, 2016 test year, based on actual data from fiscal year 2014. As required under the Notice of and Order for Hearing, it filed supplementary direct testimony and exhibits with updated 2015 rate-base and operating-statement numbers. These filings included bridge schedules to the most recently completed fiscal year (2014), to the projected fiscal year (2015), and to the test year (2016), as updated to reflect actual 2015 data through December 31, 2015.

III. Summary of the Issues

In its Notice of and Order for Hearing, the Commission directed the parties to address three issues unique to this case:

1) Other Revenue issues pertaining to MERC's Information Requirements Document No. 5, pages 3 and 4, including the adjustments to, and reduction in, Account 495—Other Gas Revenues.

2) The extent to which the cost of system upgrades to serve the City of Rochester should be borne by all MERC ratepayers and if so, on what basis.

3) Whether the test year in this case and in future MERC rate cases should be so far removed from the most recent fiscal year and whether the test year should be allowed to start more than 60 days after the filing date.

On the first issue, the parties and the ALJ determined that essentially none of the revenues in Account 495 flow through to MERC's revenue requirement, that the revenues have no impact on the 2016 test year, and that the account is therefore a non-issue in this case.[10] The Commission concurs.

The second issue was referred to the stand-alone proceeding the Commission opened to examine all issues relating to phase II of the Rochester expansion project. The issue will not be examined in this case.

The third set of issues—whether the 2016 test year was too far removed from the last fiscal year and whether future test years should start no more than 60 days after the initial rate-case filing—was resolved in the negative by the parties and the ALJ.[11] They agreed that in this case, neither the interval between the test year and the fiscal year, nor the interval between the rate-case filing and test year, was long enough to be problematic. They also agreed, however, that the second interval should not normally exceed the 93 days in this case, and the Commission concurs.

Many initially contested issues were resolved in the course of evidentiary proceedings. The Administrative Law Judge found that the resolutions reached by the parties were reasonable and supported by record evidence; she recommended accepting them.[12] The Commission concurs.

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

---

[10] ALJ's Report ¶ 28 & n.30.

[11] ALJ's Report ¶¶ 730–36.

[12] ALJ's Report ¶¶ 335–513, 711–67.

<u>Financial Issues</u>

- ***Rate-Base Treatment of Regulatory Assets and Liabilities Related to Pension and Other Post-Employment Benefits—***Should the Company be permitted to include in test-year rate base some $13,441,441 in nine regulatory asset and liability accounts related to pension and other post-employment benefits?

- ***Improved-Customer-Experience-Project Costs—***Has the Company demonstrated that the costs of its Improved Customer Experience Project are reasonable and prudent?

<u>Cost-of-Capital Issues</u>

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

<u>Class-Cost-of-Service-Study Issues</u>

- ***Adequacy of Company's Class-Cost-of-Service Study—***Has the Company demonstrated that its Minimum Size and Zero Intercept class-cost-of-service studies are factually and methodologically sound and that it is reasonable to rely on its Zero Intercept study for rate-design purposes?

- ***Requirements for Class-Cost-of-Service Studies in Next Rate Case—***Should the Commission require the Company to include in its next rate-case filing class-cost-of-service studies using the Average and Excess allocation method and the Basic System allocation method?

- ***Former Customers of Interstate Power and Light—***Are the class-cost-of-service studies filed in this case adequate for setting rates for the customers the Company acquired from Interstate Power and Light in 2015, or are separate class-cost-of-service studies required?

<u>Rate-Design Issues</u>

- ***Interclass Revenue Apportionment—***What percentage of the revenue requirement should be allocated to each customer class?

- ***Customer Charges—***At what levels should the Commission set the fixed customer charges for the Residential and Small Commercial and Industrial customers who were acquired from Interstate Power and Light in 2015? At what level should the Commission set the fixed customer charge for all other customers?

- ***Decoupling Pilot Program—***Should the Company be required to extend its decoupling pilot project to all customer classes with more than 50 customers? Should the Company be required to demonstrate energy savings of at least 1.2% as a condition of implementing any decoupling-related surcharge? Should the Company be required to explain why Residential energy conservation has declined since decoupling began?

- ***Transportation Imbalance Process—***Should the Company be required to change its compensation rate for curtailed Transportation customers to the price of gas at the time the Company gives notice of a Critical Day or Operational Flow Order? Should the Company be required to post on its website explanatory information regarding each Critical Day or Operational Flow Order called?

- ***Joint Rate Service—***Should the Company revise its tariff for this service to ensure proper cost allocation? Should the Commission open a new docket to explore issues of potential cross-subsidization?

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

IV. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held two days of formal evidentiary hearings and four public hearings. She reviewed the testimony of 28 expert witnesses and related hearing exhibits. She heard testimony from members of the public and read all written comments submitted by members of the public.

The ALJ received and reviewed initial and reply post-hearing briefs from the parties, as well as their proposed findings of fact and conclusions of law. She made 773 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. Regulatory Assets and Liabilities Related to Pension and Other Benefits

A. Introduction

MERC included in the proposed test-year rate base nine regulatory asset or liability accounts related to pension and other post-employment benefits, with a net asset balance of $13,441,441. MERC proposed to treat the funded status of these accounts as a regulatory asset included in rate base.

Account	Balance
128515 Post-Retirement Life Asset	$26,530
128525 Prepaid Pension – Retirement	$5,928,532
182312 Reg Asset-FAS 158	$9,942,914
228300 Def. Cr-Sup Ret Select SERP	($175,772)
228305 Supple Remp Ret Plan SERP	$100,000
228310 Pension Restoration	($64,396)
228315 Post Ret. Health Care - Admin	($1,785,326)
228320 Post Ret Health Care – Non Admin	($528,103)
Total per DeMerritt Direct p. 45	$13,444,379
254490 Reg Liab-FAS 158	($2,938)
Total	**$13,441,441**

The Department disagreed with rate-base treatment of these accounts. Financial reporting guidance for defined-benefit plans has changed over the years and is now consolidated in Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 715, which the Department relied on. This is the current financial standard, and requires that companies with defined-benefit retirement plans report the overfunded or underfunded status of their plans as a net asset or net liability on the company's balance sheet. Treatment under ASC 715 contrasts with the prior treatment of these assets by the FASB, where the funded status of a company's pension assets and pension obligations was allowed to be reported as a footnote to the company's financial statements.

B. Positions of the Parties

1. MERC

MERC argued that it should be allowed to include pension and other post-employment benefit amounts in rate base for the following reasons:

1) Contributions to the pension plan and other post-employment benefit accounts are an appropriate means to ensure adequate employee compensation and benefits;

2) The prepaid pension asset provides benefits to MERC's customers, who experience a net savings any time the amortization of the prepaid asset is less than the additional offset to pension expense;

3) Due to the timing of when assets are collected and liabilities accrue, there is net negative working capital for which MERC is not able to receive a return on funds; and

4) The prepaid pension asset can only be used to pay for employee pension costs, and should be treated similarly to any other asset MERC created to serve customers.

MERC argued that in the past the Commission has allowed inclusion of a negative prepaid pension asset (liability) in MERC's rate base, under an agreement between MERC and the OAG.[13] MERC also asserted that the Commission decision in Xcel Energy's 2013 rate case supports its position, in that the Commission authorized a return on pension assets net of deferred taxes to the extent it represents the cumulative difference between actual cash deposits minus recognized qualified pension expense costs.[14]

In its rebuttal testimony, MERC identified $118,246 of non-qualified pension assets included in Account 182312 – Regulatory Asset-FAS 158, and stated that it would not object to the removal of this amount from rate base. Finally, MERC cautioned that if the Commission removes the assets and liabilities associated with its pension and other post-employment benefit amount from rate base, the corresponding deferred taxes should also be removed from rate base.

2. The Department

The Department recommended removing the $13,441,441 in pension and other post-employment benefit regulatory assets from rate base for a number of reasons, including:

1) The amounts in the prepaid pension asset balance are not limited to shareholder contributions. MERC failed to acknowledge that the prepaid pension asset was also increased by decreases in pension expense even if there were no additional cash contributions made by MERC;

2) Regulatory assets and liabilities related to pensions are different from assets traditionally included in rate base, in that they do not necessarily represent a cash outlay by the Company or amortize over time like other assets;

3) MERC's pension plan assets and benefit obligations may go up or down depending on funding, market conditions, or amendments to the plan, meaning the balances are temporary and ratepayers could be responsible for shortfalls in the future; and

4) Contributions to the pension fund cannot be directed by the utility to other costs of service, and recovery of annual pension expenses provides adequate cost recovery to the Company.

The Department asserted that the balance of Account 128525 ($5,928,532) should not be allowed in test-year rate base, because ratepayers should not have to pay a rate of return on this balance, which is merely a reporting requirement to show the funded status of the account.

---

[13] *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, at 31 (July 13, 2012) ("2010 MERC Rate Case Order").

[14] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, E-002/GR-13-868, Findings of Fact, Conclusions of Law, and Order (May 8, 2015).

The Department argued that the balance of Account 182312 should not be allowed in test-year rate base as it represents unrecognized gains and losses held in Accumulated Other Comprehensive Income in the shareholder's equity portion of the Company's balance sheet. Further, Account 182312 includes amounts related to all benefit plans, even ones for which the Commission has previously not allowed any expense, much less rate-base treatment.

Further, the Department argued that the Commission rejected a similar proposal by MERC for rate-base treatment of its prepaid pension asset in its 2013 rate case. The Department stated that there was no change in circumstances that would justify a change in regulatory treatment in this rate case. The Department disagreed with the Company that the Commission's handling of the prepaid pension asset in the Company's 2010 rate case has precedential merit, reasoning that it was based on an agreement between the Company and the OAG. The Department also disagreed that Xcel's 2013 rate case provided support for the Company's position, arguing that the issue was not specifically litigated in that matter.

Finally, the Department argued that it is unaware of any rate case in Minnesota where the Commission has allowed a balance from the equity section of a company's balance sheet to be included in rate base to be charged to ratepayers. The Department recommended that the Commission make a corresponding adjustment to deferred tax liabilities reflected as an increase in MERC's test-year rate base of $5,479,921. This amounts to a net reduction to rate base of $7,961,520.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed with the Department's reasoning that MERC's pension and employee benefit regulatory assets and liabilities should be excluded from the test-year rate base, and that a corresponding adjustment to deferred taxes in the amount of $5,479,921 should be reflected as an increase in rate base. The Administrative Law Judge found there was no change in circumstances from the Company's 2013 rate case that would justify rate-base treatment of pension and other post-employment regulatory benefits.

D. Commission Action

The Commission concurs with the Administrative Law Judge and the Department that MERC has not demonstrated a change in circumstances from its 2013 rate case that would justify rate-base treatment of pension and other post-employment regulatory benefits in this case.

MERC recovers its allowable pension expense from ratepayers, and is not being denied recovery of this operating cost. Further, as noted by the Department, pension-plan assets and benefit obligations go up and down depending on funding, market conditions, or amendments to the plan. The balances in the prepaid pension asset are temporary, and fundamentally different than typical rate-base assets on which the Company earns a return on investment.

Nor does the Commission find the 2013 Xcel Energy rate case treatment of pension and other post-employment regulatory assets to be persuasive or precedential. As noted by the Administrative Law Judge, in the Xcel rate case the question of whether a company's pension asset is properly included in rate base was not specifically litigated by the parties.

Instead, the Commission finds no basis upon which to change its conclusion from that in the 2013 MERC rate case and will disallow rate-base treatment of pension and other post-employment benefit amounts. Accordingly, the Commission accepts and adopts the Administrative Law Judge's Findings of Fact on pension and other post-employment-benefit assets and liabilities and will require that the nine regulatory asset and liability accounts identified in Finding 221 of the Administrative Law Judge's Report be excluded from rate base and that a corresponding adjustment be made to deferred taxes.

VI. Improved Customer Experience

A. Introduction

Since 2006, MERC has used a third-party vendor, Vertex, to handle customer billing and payment processing, operate a call center for customer inquiries, and manage installation and repair crews. Vertex's system became outdated, however, and no longer provided modern levels of customer service or met needed data-protection, security, or accuracy standards. MERC's agreement with Vertex was ended in July 2016.[15]

Over the last several years, MERC's former parent company, Integrys, developed what it described as a modern, full-service customer-relations and billing department—the Improved Customer Experience (ICE) project—designed by an Integrys subsidiary.[16] The ICE program was designed to replace Vertex's system and the other legacy Integrys utility systems, and to obtain internal efficiencies and provide necessary services to all six of Integrys's regulated utilities. The ICE system platform handles billing, credit and collections, payments, and service-order processing, as well as replacing the utilities' telephone systems, web-based self service, and customer data-security systems

In MERC's 2013 rate case, the Commission deferred MERC's present and future costs for the ICE project development as a regulatory asset until the Company's next rate case, reasoning that the project was not yet used and useful.[17] MERC originally estimated total costs to be recovered from ratepayers for the project of some $88 million. The total budget was updated and costs for the project increased to approximately $118 million in February 2015.

In this rate case, MERC seeks recovery of its proportionate share of the deferred development costs, ongoing operations and maintenance expenses, licensing costs and depreciation, and a return on asset for software associated with the ICE project of $9.84 million over the life of the project (approximately $1.2 million more than initially estimated). These costs will be cross-charged to MERC over 15 years or 3 years (depending on the component) from the in-service date of the project (January 25, 2016).

[15] MERC included a credit of $3,374,963 in the 2016 test year for discontinuing the Vertex contract.

[16] WEC Business Systems, LLC (WBS), was assigned to complete the ICE project.

[17] *In the Matter of a Petition by Minnesota Energy Resources Corporation for Authority to Increase Natural Gas Rates in Minnesota*, G-011/GR-13-617, Findings of Fact, Conclusions, and Order, at 58–59 (October 28, 2014) ("2013 MERC Rate Case Order").

In this case, MERC, the Department, and the OAG resolved certain issues relating to MERC's proposed recovery of ICE project costs, but two issues remained. The first was a challenge by the OAG to MERC's full recovery of ICE project costs. Second, as discussed below, the Department and MERC initially disagreed about whether interim measures are needed to address the possibility that MERC's corporate parent (WEC) might expand implementation of the ICE system beyond the Integrys legacy utilities, to include two WEC legacy utilities prior to MERC's next rate case.

B. Positions of the Parties

1. The OAG

The OAG challenged the $30 million increase in capital costs of the ICE system ($118 minus $88 million) that occurred in February 2015 as not prudent or reasonable. The agency argued that there was no record established in this proceeding of the claimed benefits derived from the project (improved data security, improved usability for frequently used windows, and additional off-peak access for call-center agents) in the test year. The OAG argued that MERC has not met its burden of proof that the benefits of the ICE system are sufficient to justify the increased costs of the project, and that MERC has failed to include such benefits as a reduction of its costs for the project in the test year. The OAG also asserted that the claimed benefits of the project are largely unquantifiable and not sufficient to justify the additional costs going forward.

The OAG also asserted that an updated Net Present Value Revenue Requirement (NPVRR) analysis for the ICE project showed that it was not cost effective. In an analysis done by MERC in its 2013 rate case, Integrys had chosen the option with the greatest NPVRR ($37.2 million) over two others options (with a negative NPVRR of $1.9 million or a positive NPVRR of $19.7 million). In the updated analysis, which used the increased budget for the project, the NPVRR was $5.4 million. From this, the OAG argued that the MERC had failed to provide a sufficient explanation to justify the $30 million increase in costs from the 2013 estimate of $88 million.

The OAG claimed that MERC did not adequately investigate the costs of a stand-alone system for a utility of MERC's size, instead relying on the project designer's unsubstantiated testimony that a stand-alone system would cost approximately $21–$23 million. The OAG, referring to a 2015 industry study done by Navigant Research cited by MERC witness Brian Kage, argued that an adequate system for a utility of MERC's size should cost approximately $25–$30 per meter, not $54 per meter as advanced by MERC.

Further, the OAG argued that customers will not realize benefits from the increased project costs in the test year, yet customers are being asked to bear the full cost of the ICE project based on an as-yet-unfulfilled promise that costs should be reduced in the future.

Finally, the OAG recommended that the ICE project costs be capped at $88 million, and the Company be required to do a downward depreciation cost adjustment of $760,922, based on its proxy depreciation cost calculation. As an alternative, the OAG recommended the Commission allow total cost recovery from ratepayers of $27.50 per meter. The OAG averaged the $25–$30 cost per meter as estimated in the Navigant study as a proxy for this recommendation. The OAG argued that its recommendation is reasonable because MERC did not consider a stand-alone option or investigate the cost to serve only MERC.

2. MERC

MERC explained that the increase in costs, from $88 million to $118 million, was primarily due to the unanticipated complexity of the upgrades to the customer information system platform and the increased duration of the project. MERC stated that it spent approximately nine months designing and evaluating the improvements to the ICE system, and argued that it had made all reasonable efforts to manage and control the costs after the complexities in the system were discovered.

These efforts included (1) continuous tracking and management of the project status and implementation, (2) contract negotiation with the project vendor to obtain reduced-cost or free work, and (3) amendments to the management process. MERC also stated that it had provided the OAG with all the Company's project management files and weekly and monthly status reports from 2012 to the beginning of 2016.

MERC disagreed with the OAG's claim that the updated NPVRR shows the project is not cost-effective. MERC argued that it is not meaningful to compare the NPVRR of the current project to the Company's 2012 analysis predating the 2013 rate case, which did not include sunk costs or account for project cost changes that occurred in the interim. MERC argued that the OAG's analysis failed to take into account that the same issues that caused costs to increase for the ICE project would have also affected other options that were considered in the analysis conducted in 2012.

MERC stated that its costs to implement the project were $54 per customer, which is lower than the costs of comparable customer-information-and-billing-system projects. MERC argued that this cost was reasonable, as the ICE program now includes additional benefits such as two-layer data security, a better platform for providing information to customers, and call-center agents having additional off-peak-hours access to customer data to resolve customer questions.

As support for its per-customer cost, MERC relied on an industry study done by Navigant Research. MERC argued that the Navigant Report supports its argument that an average per-meter cost for an upgraded customer-information/billing system for a utility of MERC's size would be significantly more than $54 per customer.[18] MERC argued that the $27.50 cost per meter advanced by the OAG would not provide a solution of the scale of the ICE project, and with the level of benefit to customers, at the current cost level. MERC also asserted that its customers are benefitting from economies of scale due to the pursuit of an overall solution for all of the legacy Integrys utilities.[19]

MERC disagreed with the OAG's argument that it had not adequately justified the costs of the ICE project. MERC asserted that it was necessary to implement the project because the Vertex system was outdated and the Company had no choice but to update its customer-information system. MERC argued that the increased costs were necessary to complete the project, noting that it had already invested significant resources in the project, which would be lost if the Commission were to adopt the OAG's recommendation.

[18] Ex. 23, at 15 (Kage Rebuttal).

[19] *Id.* at 16.

Finally, MERC argued that the $25-to-$30-per-meter solution noted in the Navigant Report was less sophisticated than the more comprehensive solution it would obtain in conjunction with the other Integrys utilities, and would actually degrade the level of customer service MERC has provided to customers in the past.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that MERC has shown by a preponderance of the evidence that it was necessary to update its customer-information system because the Vertex system was outdated. She also found that the ICE project provides a positive value for MERC customers, including important data-security and web-based-customer-service features.

The Administrative Law Judge agreed with the OAG that utilities with fewer than 300,000 customers, like MERC, may be able to obtain more cost-effective customer-information-system solutions, for less than the $54 per-customer cost requested by MERC. She found that the record is clear that MERC and Integrys did not investigate a MERC-only option, nor obtain any bids to determine how much a comparable MERC-only solution would cost. Hence, she found insufficient evidence to conclude that the ICE project was more cost-effective than a comparable MERC-only solution.

The Administrative Law Judge found that MERC has not yet shown that the full $9.84 million it seeks to recover from MERC's ratepayers is reasonable and prudently incurred. She agreed with the OAG that MERC has not demonstrated that the increased costs for the project are reasonable, and recommended that the full costs of the project be recovered only if they are less than a MERC-only solution.

The Administrative Law Judge recommended that the Commission require the Company to obtain and file a detailed estimate of the costs of a comparable MERC-only solution from a vendor chosen in consultation with the Commission and interested parties. Until that filing is made and reviewed, the Commission could allow recovery of the ICE project costs as currently proposed by MERC, subject to true-up if necessary after comparison to a MERC-only option.

Finally, the Administrative Law Judge found the OAG's suggestions to cap MERC's recovery at $27.50 per customer and/or to cap recovery at the initial $88 million estimate amount are not supported by the record.

D. Commission Action

The Commission finds that the Company has satisfactorily demonstrated that it was necessary to update its customer-information system because the Vertex system was outdated. The Commission also agrees with the Administrative Law Judge that the ICE project will provide positive benefits for MERC's customers.

That being said, the Commission also concurs with the Administrative Law Judge that MERC has not demonstrated that the full increased costs of the ICE project it seeks to recover from MERC's ratepayers are reasonable and prudently incurred. MERC and Integrys did not fully investigate a MERC-only option or obtain any bids to evaluate the cost of a comparable MERC-only solution. The Commission therefore will allow MERC cost recovery of the ICE project based on MERC's share (approximately $9.84 million) of the updated total ICE project budget, but only if MERC demonstrates that the ICE project is effective and meets appropriate customer-service benchmarks to be developed as discussed below.

The Commission disagrees with the methodology suggested by the Administrative Law Judge to true up recoverable costs to a hypothetical MERC-only option. Given that the project is designed to improve customer service, the Commission will order that $500,000 be refunded to ratepayers for 2016, due to the Company's failure to prove that the additional expense above historic levels was reasonable and prudent.

Further, on an annual basis, starting in 2017, MERC shall place $500,000 from ratepayers into an account and adhere to the following:

1) By February 2017 MERC shall develop a tool or survey to measure the effectiveness over time of the ICE project as it relates to the customer services that were intended to be improved by the project. Any survey, consultant, program, or tool to measure project effectiveness must be adopted in consultation with the Department and the OAG.

2) The Company, after consultation with the Department and the OAG, shall set annual ICE-project customer-service benchmarks to be reached by the end of 2017. The Company may modify these benchmarks and shall report annually unless the Commission determines ongoing monitoring is no longer necessary and that the $500,000 no longer needs to be set aside as a performance incentive.

3) The Company shall report performance towards these benchmarks annually at the same time they do their service-quality reporting. At that time the Commission will determine whether the benchmarks for retention of the $500,000 have been met.

The Commission will also require MERC to provide within five business days from September 29, 2016 (the date of the Commission's deliberation), as an informational filing to this order, a detailed explanation, including schedules by FERC (USOA) account number, of the annual revenue-requirement impact of the Commission's ICE project decision and how the test-year adjustments necessary to account for the ICE project are in compliance with the Commission's decision.

Finally, the Commission disagrees with the OAG's assertion that developing a revised process to evaluate whether MERC's proposed costs for the ICE project are reasonable does not hold MERC accountable, and gives the Company an unwarranted second chance to prove its case. The Company has expended significant time and money to develop the ICE program to improve its outdated customer-information system, which would be lost should the Commission require the Company to now switch to some unidentified new system.

The Commission's action further protects customers by requiring MERC to refund $500,000 to ratepayers for the 2016 test year, and requiring an annual deposit of $500,000 into an account unless and until the Company can demonstrate that the ICE project is effective and meets appropriate customer-service benchmarks, set in conjunction with the Department and the OAG.

VII. Implementation of ICE for WEC Legacy Utilities

In addition to the six legacy utilities referred to above, Integrys owned two other legacy utilities, Wisconsin Gas and Wisconsin Electric Power Company. WEC has indicated it has no plans to transition these two utilities to the ICE platform.[20] According to WEC, initiating and implementing ICE for the two Wisconsin utilities would be a complex, multiyear project.

The Department raised concerns, however, that MERC might transition these utilities to the ICE platform between rate cases or after MERC's ratepayers have paid all or most of the costs for the ICE system through rates. The issue was litigated, but following oral argument before the Commission, the Department and MERC agreed to the following, with which the Commission concurs:

MERC will provide the following information with the initial filing of its next rate case:

- An update on the decision process for WEC legacy utilities to implement the ICE system, fully justifying any decision for the WEC legacy utilities not to use ICE;

- If a process has been implemented to explore the idea, or an actual timeline has been established for WEC legacy utilities to adopt ICE, MERC shall provide a detailed discussion of the status, along with a proposal to reimburse Minnesota ratepayers for their share of the ICE system (deferred and ongoing costs); and

- If MERC does not provide this information in its initial filing in its next rate case, the initial rate-case filing shall be considered incomplete.

In the event that WEC decides to implement the ICE system for its WEC legacy utilities prior to MERC filing its next rate case, MERC should make a filing within 30 days of such a decision, which shall also be no less than 12 months before initial implementation for Integrys legacy utilities. Approval by the WEC board of directors will be considered the point of decision and will trigger the start of the 30 days.

The filing should provide details of WEC's implementation plans and a proposal for adjusting the costs paid by MERC's customers for the ICE system to ensure the costs paid by MERC's customers are reasonable. If such a filing is made prior to the next rate case, the Commission can determine, at that time, whether to revise the contents of the filing to be made by MERC in its next case, as discussed above.

[20] Ex. 414, at 14 (Byrne Direct, attaching MERC's response to the Department's Investigative Request No. 178).

VIII. Clarification of Treatment of Former-Manufactured-Gas-Plant Costs

By the close of the evidentiary hearings, MERC and the Department had largely come to agreement regarding the deferred-accounting treatment of former-manufactured-gas-plant costs. Following the Administrative Law Judge's recommendations, neither party filed exceptions, but both parties requested that the Commission clarify the 2016 treatment of these costs. Each party filed the agreed-upon language and modifications to Findings 253 and 254.

The Commission accepts the Administrative Law Judge's conclusion and recommendations, and will allow MERC to continue deferred-accounting treatment of the former-manufactured-gas-plant costs for the Austin site, as the nature of these costs has not changed. In lieu of the proposed language of the parties, however, the Commission will clarify the Administrative Law Judge's Findings as follows:

1) The 2016 former-manufactured-gas-plant costs will be deferred and amortized rather than expensed in the test year; and

2) MERC's post-2014 former-manufactured-gas-plant cleanup costs will be subject to review for prudence and reasonableness in the next rate case.

COST-OF-CAPITAL ISSUES

Utilities meet their capital needs by issuing stock, known as equity, and by incurring long-term and short-term debt; these three components make up the utility's capital structure. Generally, equity is the most expensive form of financing, followed by long-term debt and then short-term debt. The percentage of the capital structure made up of each of these components therefore has a substantial impact on costs and rates, as does the cost assigned to each component during the ratemaking process.

In this case, the only contested cost-of-capital issue is the cost of equity. The two parties who addressed cost-of-capital issues, the Company and the Department, take the same position on capital structure, the cost of long-term debt, and the cost of short-term debt.

The Commission will address the issues of capital structure and the cost of each of its components below.

IX. Capital Structure

MERC is a subsidiary of WEC Energy Group, Inc., an electric- and natural-gas-delivery company serving some 4.4 million customers in Minnesota, Wisconsin, Illinois, and Michigan. MERC therefore has no capital structure of its own and must be assigned a hypothetical capital structure for ratemaking purposes.

The Company based its proposed capital structure on its target equity ratio of 50–55%[21] and on its historical levels of long-term and short-term debt. It proposed the following capital structure:

Long-Term Debt	45.59%
Short-Term Debt	4.08%
Common Equity	50.32%

The Department reviewed the proposed capital structure and concluded it was reasonable, based mainly on comparisons with the capital structures approved in the Company's last three rate cases and the most recently reported capital structures for the six companies in the proxy group the Department used in its Discounted Cash Flow (DCF) cost-of-equity study. No one opposed the Company's proposal.

The Administrative Law Judge examined the proposal, found it reasonable, and recommended adopting it. The Commission concurs and adopts the proposed capital structure.

X. 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*.[22]

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 an opportunity 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 WEC Energy Group and therefore 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.

---

[21] Since the Company is a wholly owned subsidiary of another company, its equity consists of its retained earnings, plus equity infusions from its parent, minus dividends paid to its parent.

[22] Minn. Stat. § 216B.16, subd. 6 (emphasis added).

B. The Analytical Tools

MERC and the Department conducted cost-of-equity studies and based their analysis on groups of utilities they considered similar enough to MERC to serve as proxies in determining the Company's cost of equity. The two proxy groups were nearly identical, with the Company's group containing the Department's entire six-company group, plus one additional company.

Both parties did thoroughgoing studies using the Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance. Both also conducted studies using 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 Bond Yield Plus Risk Premium Model (RP), 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 using three inputs—dividends, market equity prices, and earnings/dividend growth rates. Its two basic variants are the Constant-Growth DCF, the classic version, and the Two-Growth DCF, designed for situations in which the short-term, projected earnings growth rates may not be expected to continue in the long run. The two-growth model uses one growth rate for an initial period, followed by a different growth rate for the long term.

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.

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.

All the models are theoretically sound and offer useable information, but the DCF model is generally the most helpful, because its inputs are more objective, its workings more transparent, and its outcomes more replicable than those of the other models.

C. Positions of the Parties

1. The Company

The Company proposed a return on equity of 10.3%, based on a multi-factor analysis not directly tied to any specific analytical model, but based on the professional judgment of its expert witness.

The Company conducted a classic DCF study, which assumes constant growth in earnings and dividends, but expanded the 30-trading-day period normally used to determine stock prices and dividends to also include 90-trading-day and 180-trading-day periods. The Company argued that using multiple trading periods reduced the risk that market anomalies would skew model outcomes. Similarly, the Company adjusted the model's growth-rate-estimate input by including its expert's retention-growth estimate as well as the three publicly available earnings-growth estimates normally used.

The Company also conducted a Multi-Stage DCF study, developing inputs for multiple time periods and extrapolating future financial performance from the results. The Company conducted a CAPM study, using 30-year treasury notes (instead of the more typical 20-year notes) as the risk-free asset the study requires. And it conducted an RP study, also using 30-year treasury notes as the baseline asset, and using coefficients that assumed no change in investors' expectations or behavior over time or in response to changes in monetary and fiscal policies.

The Company's expert weighed the results of these studies. He also weighed and factored into his analysis four factors specific to this company and this time and place—the Company's relatively small size, the high percentage of Transportation customers in its customer base, the major increase in capital investment it anticipates over the near and intermediate term, and changing capital-market conditions. He also factored in flotation costs, the costs of issuing securities, since these costs result in a utility receiving less than the full price for shares issued.

The Company's expert did not assign a specific numerical value or weight to any of these factors, but applied his professional judgment and expertise to determine that, together, they yielded a cost of equity of 10.3%. On rebuttal he updated the market-data inputs for all financial models, which reduced all models' cost-of-equity results, but concluded that the 10.3% recommendation did not require revision.

The Company argued that its analysis was superior to the Department's because it used more models, creating a more comprehensive record and balancing the limitations and deficiencies of the models against one another. It challenged the Department's 9.11% recommendation as unreasonable on grounds that it was in the lowest 11% of returns on equity granted by state utility commissions since 2014.

Finally, the Company argued that the 56-point difference between the cost of equity recommended in the Department's direct testimony and the cost of equity recommended in its surrebuttal testimony was too large to be accepted at face value. The Company pointed out that the Commission had averaged the Department's direct and surrebuttal cost-of-equity recommendations in its last rate case and recommended doing the same here, should the Commission adopt the Department's analytical approach to the cost of equity.

2. The Department

The Department proposed a return on equity of 9.11%, which is the mean of the returns on equity calculated under its two-growth DCF analysis for the six companies in its proxy group, plus a flotation adjustment of 12 basis points.

The Department also conducted a CAPM analysis and an Empirical CAPM analysis—a variant of the CAPM tailored for companies with betas lower than one—to serve as reasonableness checks on its DCF results. The agency stated that these studies confirmed the general accuracy of its DCF results but yielded returns on equity too low to be seriously considered for MERC.

The Department had originally recommended a return of 9.67%, but when it updated its DCF inputs on surrebuttal—consistent with normal rate-case practice—the mean of the returns for the companies in its proxy group fell by some 56 basis points. While original and updated DCF results nearly always differ, this 56-basis-point difference was larger than usual.

The difference was due mainly to Value Line, an investment-research firm used by both the Company and the Department in developing their DCF growth-rate inputs, adjusting its projected growth rate for the proxy group by a full percentage point, from 7.25% to 6.25%. Value Line's projected growth rate remained higher than those of the other two firms used by the parties, Zacks and Thomson First Call, but it was much closer to those firms' projections than it had been.

The Department challenged the Company's proposed cost of equity on three grounds. First, it argued that the Company's failure to explain how it weighted or balanced its modeling outcomes against one another—and against other factors—robbed the analysis of the transparency, rigor, and evidentiary support necessary for its adoption. The Department cited as an example the Company's failure to explain its reasons for declining to revise its proposed 10.3% cost of equity when its updated DCF, CAPM, and RP analyses all showed lower costs of equity than its initial analyses.

Second, it rejected the Company's claim that its cost of equity should be adjusted upward to reflect increased risks due to company size, the composition of its customer base, anticipated capital investment, and current market uncertainties, arguing that adjusting for isolated company-specific characteristics on a stand-alone basis would defeat the purpose and dilute the validity of using a proxy group in DCF modeling.

Third, it challenged the Company's execution of its DCF, CAPM, and RP studies, claiming that the following actions, among others, significantly compromised their reliability:

1) using overly long (90-day and 180-day) trading periods to project growth rates in the DCF model,

2) substituting a less reliable and more subjective retention growth rate for one of the DCF earnings growth rates,

3) using an unduly subjective and largely unsupported payout ratio in the Multi-Stage DCF model,

4) using 30-year treasury notes—instead of the less risky and more commonly used 20-year notes—as the riskless asset in the CAPM model, and

5) assuming that both coefficients in the RP analysis would be stable over time and would not change due to investors' changing expectations or behaviors as fiscal or monetary policies changed.

D. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found the Department's cost-of-equity analysis methodologically transparent, analytically sound, ably executed, consistent with longstanding practice, and supported by substantial evidence. She recommended using that analysis to set the cost of equity in this case. She found the Department's final recommendation of 9.11% reasonable and fully supported in the record.

She concurred in the Department's decision to base its cost-of-equity recommendation on the DCF analytical model, using other models as reasonableness checks, noting that the Commission has generally used this approach over the past several years. She found that in this case, too, the DCF model was more transparent, objective, and replicable than the other models in the record or than MERC's comprehensive, multi-factor approach. She found that both the CAPM and RP analytical models are highly sensitive to the individual analyst's choice of inputs and data sources, leaving them vulnerable to volatile and unreliable outcomes.[23]

She found that the record offered no clear explanation of how the Company reached its 10.3% recommendation, since MERC neither disclosed how its expert weighed the results of its three analytical models nor assigned numerical values to the four situation-specific factors it claimed raised its risk and increased its required return on equity. Similarly, she found that the Company failed to explain why it did not reduce its 10.3% cost-of-equity recommendation when the updated results of all three of its analytical models yielded lower returns on equity than its original calculations.[24]

The Administrative Law Judge also concurred with the Department in finding serious deficiencies in the Company's execution of its financial models:

> In addition, the Administrative Law Judge agrees with the Department that the record shows MERC's ROE analysis is unreasonable in other regards: 1) Mr. Hevert's use of dividend yields based on 90- and 180-day average stock prices is unreasonable because this information is outdated; (2) Mr. Hevert's use of retention growth rates in his DCF analyses is unreasonable because use of estimated earnings growth is superior to any other growth rates when using a DCF analysis and Mr. Hevert's Retention Growth rate is subject to significant estimation error because it requires estimation of four parameters; (3) Mr. Hevert's assumed long-term payout ratio of 67.67 percent in his multi-stage DCF analyses is unreasonable because it assumes a significant reversal in the trend for industry payouts; and (4) Mr. Hevert's use of 30-year Treasury bonds in his CAPM analysis as a risk-free rate was not shown to be reasonable because the 30-year Treasury bond includes an interest risk rate premium and therefore may bias the CAPM estimated ROE upward.[25]

---

[23] ALJ's Report ¶ 200.

[24] ALJ's Report ¶ 202.

[25] ALJ's Report ¶ 205 (footnotes omitted).

She concurred with the Department that the record did not support Company claims that using multiple financial models enhanced the accuracy and credibility of its cost-of-equity recommendation.[26] She rejected Company claims that its return on equity must be adjusted upward to reflect company size, the composition of its customer base, its anticipated capital investment, and current market uncertainties. She noted that the Commission had rejected this claim in the Company's last rate case and agreed with the Department that adjusting for isolated, company-specific characteristics on a stand-alone basis would defeat the purpose and undermine the validity of the DCF proxy-group process.[27]

She found that cost-of-equity decisions in past rate cases—here or in other jurisdictions—hold little probative value, quoting an earlier Commission order explaining that rate-of-return decisions are "by definition specific to the individual utilities, their service areas, and then-prevailing economic conditions."[28] She also pointed out that return-on-equity decisions dating back to 2014 are necessarily based on stale financial information.[29]

Finally, she noted the 56-basis-point difference between the Department's initial and final cost-of-equity recommendations, but found that it was adequately explained and supported by the facts in the record. The difference was caused chiefly by Value Line, an investment-research firm used by both parties for critical DCF inputs, adjusting its projected growth rate for the proxy group by a full percentage point, from 7.25% to 6.25%.

While this was a significant adjustment, it brought Value Line's projected growth rate much closer to the projected growth rates of the other two investment-research firms used by the parties, Zacks and Thomson First Call.[30] The Administrative Law Judge viewed this convergence of the firms' future growth rates as evidence of heightened—not reduced—credibility, since all three firms are highly respected and widely consulted sources of market data and analysis.

At the same time, she noted that in the Company's last rate case, when the Department's recommended cost of equity dropped between direct and surrebuttal testimony, the Commission averaged the two recommendations to ensure that potentially anomalous market volatility between the two periods did not skew the return on equity downward.[31]

While she did not consider averaging necessary here—given the evidentiary strength of the Department's recommendation on surrebuttal—she did find that averaging the two recommendations, or adopting a number between that average and the Department's final, 9.11% recommendation, would also produce a reasonable return on equity.

---

[26] ALJ's Report ¶ 204.

[27] ALJ's Report ¶ 203.

[28] ALJ's Report ¶ 206.

[29] *Id*.

[30] On surrebuttal the three firms' projected growth rates were 5.62 (Zacks), 5.52 (Thomson First Call), and 6.25 (Value Line). On direct, those projections had been 5.56 (Zacks), 5.58 (Thomson First Call), and 7.25 (Value Line). Ex. 413, at 9 (Kundert Surrebuttal).

[31] 2013 MERC Rate Case Order, at 31–32, 40–41.

E. Commission Action

1. Introduction

The Commission concurs with the Administrative Law Judge's closely reasoned findings, conclusions, and recommendations on the cost of equity and will set that cost at 9.11%, the level recommended by the Department and found to be reasonable by the Administrative Law Judge.

The Commission agrees with the Administrative Law Judge that the Department's cost-of-equity studies are methodologically transparent, analytically sound, ably executed, and supported by substantial evidence. They are the best evidence in the record on the cost of equity, and the Commission concurs in the Administrative Law Judge's acceptance and adoption of them.

2. Use of Multiple Analytical Models

The Commission concurs with the Administrative Law Judge in rejecting the claim that using multiple cost-of-equity models produces more trustworthy results than relying primarily on the strongest model, the DCF, and using the other models as reasonableness checks. While every cost-of-equity determination is fact- and record-specific, the Commission has rejected that claim in the Company's last three rate cases:

> 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.
>
> 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.[32]

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. Company-Specific and Market-Specific Risk Adjustments

The Commission also concurs with the Administrative Law Judge that it would be inappropriate to adjust the cost of equity upward to reflect Company-specific characteristics that it argued raised its business risks—its small size, its high number of Transportation customers, and its projected major capital investments. The Commission concurs with the Department and the ALJ that these risks—together with all company-specific strengths—have been subsumed into the mix of characteristics of the companies in the proxy groups and that adjusting for isolated, company-specific characteristics cutting only in favor of a higher return would improperly skew the DCF analysis. As the Commission explained in the recent Great Plains rate case:

> The proxy groups used in this case were carefully vetted, using objective criteria such as credit ratings and percentage of revenues drawn from specific business lines, to ensure their overall comparability to Great Plains. Making additional adjustments at this point for the characteristics cited by the Company would be likely to result in double-counting.
>
> Further, it would not capture any offsetting, Company-specific strengths that were also factored into the composition of the proxy groups. And even if Company-specific strengths and risks could be identified at this point, it is highly improbable that the additional complexity and subjectivity this analysis would require would increase accuracy beyond that provided by relying on the integrity of a properly assembled comparison group. In short, it would disrupt the workings and compromise the results of the DCF model by inserting subjective judgments at a stage that is designed to be free of them.[33]

---

[32] 2010 MERC Rate Case Order, at 20–21. *See also* 2013 MERC Rate Case Order, at 32–33; *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-08-835, Findings of Fact, Conclusions of Law, and Order, at 10–11 (June 29, 2009).

[33] *In the Matter of the Petition by Great Plains Natural Gas Co. for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-004/GR-15-879, Findings of Fact, Conclusions, and Order, at 24 (September 6, 2016).

Similarly, the Commission concurs with the Administrative Law Judge that it would not be appropriate to adjust the analytical models' cost-of-equity results to reflect current market conditions or the abiding uncertainty about future market conditions.[34] The models used to calculate the cost of equity incorporate all publicly available information about the Company (or its closest proxies), current market conditions, and investors' expectations regarding future market conditions. Factoring uncertainty about future market conditions into the cost-of-equity equation at the end of the process would introduce speculation and double-counting; it would not enhance accuracy.

4. Difference Between Original and Updated DCF Results

Finally, the Commission concurs with the Administrative Law Judge that the Department's final 9.11% cost-of-equity recommendation is fair, reasonable, and fully supported in the record, despite being 56 basis points below its original recommendation of 9.67%.

As explained earlier, the original and final recommendations were derived in the same way, by averaging the returns on equity calculated under the two-growth DCF model for the companies in the Department's proxy group and adding a flotation adjustment. The original recommendation was based on 30 trading days of market data ending on February 24, 2016; the final recommendation was based on 30 trading days of market data ending on April 29, 2016.

It is standard rate-case practice for parties to conduct a final run of their financial models, using the most current market information available, before submitting their final return-on-equity testimony. Their original and final model results—and their original and final return-on-equity recommendations—nearly always differ; the 56-basis-point difference in this case, however, was larger than usual.

The difference was caused mainly by Value Line, an investment-research firm used by both the Company and the Department in developing their DCF inputs, adjusting its projected growth rate for the proxy group by a full percentage point, from 7.25% to 6.25%.[35] While this was a significant adjustment, it brought Value Line's projected growth rate much closer to the projected growth rates of the other two investment-research firms used by the parties, Zacks and Thomson First Call.

The Administrative Law Judge viewed this convergence of the three firms' future growth rates as evidence of heightened—not reduced—credibility, since all three firms are highly respected, widely consulted sources of market data whose projections merit and receive careful consideration.[36] The Commission concurs. Closer alignment of the projected growth rates of these three firms indicates less uncertainty and volatility in the DCF growth-rate input than would a broad range of projected growth rates. The realignment supports, not undermines, the credibility of the Department's 9.11% surrebuttal recommendation.

---

[34] ALJ's Report ¶ 204.

[35] Increases in stock prices and increases in annual dividends also contributed to the difference between the two recommendations, but those two factors together accounted for only 27% of the 56-basis-point drop.

[36] ALJ's Report ¶ 213.

Finally, the Commission notes, as the Administrative Law Judge did, that in the Company's last rate case the Commission averaged the Department's direct and surrebuttal cost-of-equity recommendations to ensure that potentially anomalous market volatility between the two periods did not skew the return on equity downward.[37] The Company urges the same treatment of those recommendations here.

The Commission disagrees. Every cost-of-equity determination is fact-intensive and record-specific. Here there is no evidence of anomalous market volatility or other aberrant conditions requiring departure from the longstanding practice of basing the return on equity on the most recent market data available. That practice is based on the fundamental financial principle that the most recent market data encompasses all publicly available information and therefore captures current market conditions and investors' expectations more reliably than any other resource.

The Commission concludes that the best evidence in the record therefore supports setting the Company's return on equity at 9.11% as recommended by the Department.

XI. Cost of Long-Term Debt and Short-Term Debt

The Company initially proposed a long-term-debt cost of 5.1114% and a short-term-debt cost of 3.0545%, based on average debt costs over a 13-month period from December 1, 2014, to December 31, 2015.

The Department concluded that the Company had used a reasonable method to calculate the cost of long-term and short-term debt and that both costs were reasonable, given current market conditions and compared with the Company's past debt costs. The Department also examined these costs in light of the order authorizing WEC's acquisition of MERC, which prohibited any pass-through to Minnesota ratepayers of higher debt costs resulting from the acquisition.[38] Although the cost of debt had gone up since the acquisition, the Department concluded that the increase did not result from the acquisition, but from general economic conditions.

The Department did, however, recommend updating the cost of debt on surrebuttal, based on then-current market conditions. At that point the Department recommended a 4.8627% cost of long-term debt and a 2.0370% cost of short-term debt. The Company supported both figures, and the Administrative Law Judge found them supported by substantial evidence and recommended their approval.

The Commission concurs and adopts a cost of long-term debt of 4.8627% and a cost of short-term debt of 2.0370%.

---

[37] 2013 MERC Rate Case Order, at 31–32, 40–41.

[38] *In the Matter of a Request for Approval of the Merger Agreement Between Integrys Energy Group, Inc. and Wisconsin Energy Corporation*, Docket No. G-011/PA-14-664, Order Approving Merger Subject to Conditions, at 10 (June 25, 2015).

XII. Final Capital Structure and Overall Cost of Capital

The final capital structure and overall cost of capital resulting from the decisions made in this order are set forth below:

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	45.59%	4.8627%	2.2169%
Short-Term Debt	4.08%	2.0370%	0.0831%
Common Equity	50.32%	9.1100%	4.5842%
Total			6.8842%

CLASS-COST-OF-SERVICE-STUDY ISSUES

XIII. Class-Cost-of-Service Study

A. Introduction

1. Role of Class-Cost-of-Service Study

An energy utility filing a general rate case must include a Class-Cost-of-Service Study (CCOSS), allocating the utility's costs among its customer classes in a manner intended to reflect the cost of serving each class. Minn. R. 7825.4300(C) directs a utility to file

> A cost-of-service study by customer class of service, by geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class of service, geographic area, or other appropriate category, identifying the procedures and underlying rationale for cost and revenue allocations.

There are many ways to make such allocations. The Commission values studies that are based on clear assumptions that render clear results.

Certain kinds of costs increase as a customer's consumption of energy increases (commodity or energy costs). Other kinds of costs increase as the rate at which the customer consumes energy increases, especially during periods of peak demand (capacity or demand costs). And still other costs increase as the number of customer accounts increases (customer costs). The classification of costs has important rate consequences because each type of cost is allocated among the customer classes in a different way. For example, because the great majority MERC's customers are residential customers, a choice to characterize a cost as a customer cost will result in residential customers bearing the great majority of those costs.

Allocation of commodity costs are generally not a large issue for a gas distribution utility's CCOSS because the Commission authorizes utilities to recover these costs via the fuel portion of the utility's base rates, with periodic adjustments implemented via a special mechanism called the fuel clause. So the central issue for a natural gas distribution utility's CCOSS is to determine how to divide the cost of its distribution system—consisting primarily of its gas mains and related facilities—between capacity costs and customer costs. Because a utility must build its distribution plant to have sufficient capacity to provide all the gas demanded simultaneously by its firm customers, all parties agree that some share of this cost is related to capacity. But parties disagree about how much of the distribution plant cost to characterize as customer-related costs; this disagreement is reflected in the CCOSS methods they espouse.

2. Types of Studies

Parties variously espouse the Basic System method and the Minimum System method, as well as a variant known as the Average and Excess method.

The *Basic System method* reflects the premise that only costs that can be traced back to individual customers—such as the costs of service lines, meters, billing, and collection—should be classified as customer costs. The rest of the distribution plant is a shared asset built to deliver the maximum amount of energy demanded by the customers—and these costs should be classified as capacity costs.

In contrast, the *Minimum System method* reflects the premise that a utility builds out its distribution plant to serve each customer regardless of the amount of demand that customer puts on the system, and thus *some* portion of the plant should be regarded as customer-related. MERC identifies two types of Minimum System CCOSSs: a Minimum Size study and a Zero Intercept study.

A *Minimum Size study* estimates the cost a utility would have incurred to build its distribution system at some minimal capacity, and assigns this amount to customer costs. To use this method, a utility first calculates the length of pipe it has in its distribution system. Then it identifies a distribution pipe of "minimum practical size," meaning the pipe with the smallest diameter that fairly represents what is actually installed within a utility's distribution system. The utility calculates the average cost per foot to buy and install this small-diameter pipe, and then multiplies this by the length of pipe in the utility's distribution system. The result is designated the customer cost; the remainder of the cost of the distribution system is designated capacity cost.[39]

In the Minimum Size study, however, parties may disagree about the magnitude of the "minimum practical size" pipe to use for the study, which may affect the study's results. Also, because even a minimum system will have some capacity for delivering gas, a Minimum Size study will inevitably misidentify some capacity-related costs as customer costs.

In contrast, a *Zero Intercept* study avoids these disputes. Recognizing that larger capacity pipes cost more to buy and install than smaller pipes, a Zero Intercept study calculates (using ordinary-least-squares regression analysis) the relationship between pipe cost and pipe capacity. Based on this relationship, the study estimates the cost of installing a hypothetical pipe with zero capacity. Costs associated with building a distribution system with no capacity are regarded as customer costs. All additional costs of the distribution plant are presumed to be caused by the need to provide capacity, and are therefore regarded as capacity costs.

[39] *See generally* Staff Subcommittee on Gas, National Association of Regulatory Utility Commissioners, Gas Distribution Rate Design Manual (1989).

While a Zero Intercept study has advantages over a Minimum Size study, it also has the disadvantage of being more burdensome to generate and requiring more data.

One additional perspective is provided by the *Average and Excess* method.

Each of these CCOSS methods allocates capacity cost among customer classes based on each class's share of total gas consumption during the utility's coincident peak demand. These studies reflects the idea that a utility designs and builds its system to have sufficient capacity to meet the needs of all its firm customers during periods of peak demand, no matter how brief that period is. In practice, this dynamic causes residential consumers to bear a larger share of these costs relative to the amount of gas consumed than do industrial customers.

The Average and Excess method ameliorates this dynamic. This method characterizes all distribution-system costs as capacity costs, but rejects the premise that these costs should be allocated purely on the basis of coincident peak demand. Instead, the Average and Excess method allocates some costs based on each class's average level of usage, reflected by each class's energy consumption or average demand. And it allocates the rest based on peak demand—but the peak demand of *each customer class*, regardless of when that peak occurs (non-coincident peak demand).[40] This has the effect of assigning less costs to residential customers, and more to industrial customers, than would occur under other cost study methods.

3. MERC's Last Rate Case

In MERC's last rate case the Commission directed MERC to prepare and file two types of CCOSSs based on the Minimum System method—specifically, a Minimum Size study and a Zero Intercept study—in its next rate case. The Commission directed MERC to file both studies to provide different perspectives on customer costs.

Also, while the Commission approved MERC's last Zero Intercept study, the Commission directed MERC to improve upon its analysis in its next rate case by

- collecting data on additional variables that impact the unit cost of mains installation;
- avoiding aggregating or averaging data, and using data at the finest level reasonable;
- checking ordinary-least-squares regression assumptions and correcting for violations; and
- making any future Zero Intercept analysis more transparent to permit other parties to replicate MERC's work.[41]

[40] Ex. 304, at 10–12 (Nelson Direct).

[41] 2013 MERC Rate Case Order, at 47.

B. Positions of the Parties

1. The Company

Consistent with the Commission's order in MERC's last rate case, MERC filed both a Minimum Size study and a Zero Intercept study. MERC also reports that it complied with the Commission's four instructions for refining MERC's Zero Intercept study method.[42]

Ultimately, MERC recommended that the Commission rely on the Zero Intercept study to guide the allocation of costs among the customer classes, reasoning that this study rested on more—and more detailed—data than the Minimum Size study.[43] In any event, MERC claimed that the two studies largely corroborate each other's findings.

2. The Department

Having reviewed MERC's CCOSSs, the Department found that MERC adequately complied with the Commission's directions in MERC's last rate case and that MERC's Zero Intercept study provides useful guidance for the Commission's allocation of costs among revenue classes.[44]

Nevertheless, the Department concluded—and MERC agreed—that MERC should further improve future CCOSSs by starting to collect and maintain more specific data about the individual projects that MERC pursues in enhancing and maintaining its distribution plant.

3. The OAG

The OAG recommended that the Commission consider multiple models when determining how to apportion costs among customer classes, based on the theory that no single model perfectly captures how a utility incurs costs to serve each customer class.

Specifically, the OAG recommended that the Commission give the greatest weight to the OAG's CCOSS model, developed using the Basic System method. The OAG expressed concerns about MERC's Minimum System study, but concluded that the Commission would be justified in giving weight to that analysis as well.

In contrast, the OAG recommended that the Commission reject MERC's Zero Intercept study, arguing that MERC failed to adequately implement the corrections that the Commission required in MERC's last case. The OAG argued, for example, that MERC improperly eliminated certain variables from its analysis, improperly relied on averaged data, and violated the conditions required to conduct an ordinary-least-squares regression analysis.

Moreover, the OAG argued that MERC erred in developing its costs without distinguishing between the roughly 5% of MERC's customers residing in areas that had been served by Interstate Power and Light (IPL), and the rest of MERC's customers. MERC has served these customers in and around the City of Albert Lea only since May 1, 2015, when it acquired certain

---

[42] Ex. 34, at 30–69 (Hoffman Malueg Direct).

[43] *Id*. at 28–29.

[44] *See generally* Ex. 409 (Zajicek Direct).

assets from IPL; the OAG hypothesized that these customers might have different characteristics than MERC's other customers. This led the OAG to recommend that the Commission give no weight to MERC's CCOSSs with respect to customers in IPL's former service areas—although the OAG later retracted its recommendation in oral arguments before the Commission.

Finally, the OAG recommended that the Commission direct MERC to include in its next rate case a CCOSS using the Basic System method, as well as a study based on the Average and Excess method.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concurred with MERC and the Department that MERC had taken appropriate steps to comply with the Commission's prior order to refine its CCOSSs, and that MERC had filed the required Minimum Size study and Zero Intercept study in the current docket.

The Administrative Law Judge rejected the OAG's argument that MERC erred in failing to distinguish between customers in service areas formerly served by IPL and the rest of its customers. The record revealed no instance in which the Commission had required a separate cost study for customers in a newly acquired service area. Moreover, the Administrative Law Judge cited testimony from MERC and the Department disputing the suggestion that IPL's former customers had different costs than MERC's other customers, and stating that MERC's CCOSSs accounted for the characteristics of the former IPL customers.

In choosing among the positions advocated by the parties, the Administrative Law Judge found greater support for the position advocated by MERC and the Department. She found that MERC did not design its distribution plant solely to provide capacity to meet peak demand, but also to connect to and serve individual customers. This dynamic is reflected in MERC's Minimum Size study and Zero Intercept studies, but not in the OAG's Basic System CCOSS. For this reason, the Administrative Law Judge found that the record did not support relying on the Basic System CCOSS for purposes of apportioning costs among customer classes in this rate case.

As between MERC's two studies, the Administrative Law Judge found the Zero Intercept study more persuasive because it was built on greater data and calculated a level of customer cost that was distinct from any capacity function.

Finally, the Administrative Law Judge noted that the Commission had accepted other CCOSS methods in a recent rate case. She was able to reconcile the holding of that case with her recommendation in this one. Nevertheless, the Administrative Law Judge proposed that the Commission consider initiating a generic docket for Minnesota's gas utilities to explore how to apportion the cost of the distribution plant among customer classes.

D. Commission Action

Having reviewed the parties' evidence and arguments, the Commission generally concurs with the ALJ's Report.

Specifically, for purposes of the current docket the Commission will rely on one of MERC's Minimum System CCOSSs rather than the OAG's Basic System CCOSS. A Minimum System

CCOSS recognizes that a gas utility's distribution plant is designed both (1) to meet system capacity needs and (2) to connect customers regardless of their individual capacity needs. The Basic System CCOSS does not reflect this dynamic.

In choosing between MERC's two Minimum System CCOSSs, the Commission concurs with MERC, the Department, and the Administrative Law Judge that MERC's Zero Intercept study provides the most useful tool in the record for distinguishing between customer-related costs and capacity-related costs. The Minimum Size study, which calculates customer cost on the basis of a hypothetic distribution plant of some minimum size greater than zero, would be expected to overestimate customer costs. As previously noted, the Commission values studies that are based on clear assumptions that render clear results. In this case, the Commission finds that the Zero Intercept study generated clearer results than the Minimum Size study.

The Commission finds that MERC's CCOSSs comply with Minn. R. 7825.4300(C) The studies are designed to apportion the costs of MERC's distribution plant among its customer classes on the basis of cost causation. The studies show revenues, costs, and profitability for each class of service, and identify the procedures and underlying rationale for cost and revenue allocations.

The Commission finds that MERC's CCOSSs comply with the Commission's prior orders for refining MERC's methodology. While the OAG claimed that these studies suffered from methodological shortcomings, the Department evaluated these claims and found them to be unsubstantiated, or insufficient to indicate that the study's results would be biased.

And the Commission finds no basis for the OAG's claim that MERC should have excluded former IPL customers from MERC's cost studies. MERC provided credible testimony that customers in the Albert Lea area are relatively homogenous with other MERC customers in their respective customer classes, and that MERC's CCOSSs appropriately accounted for the load profiles of the Albert Lea customers.[45]

That said, the Commission concurs with the Department's recommendation, and MERC's agreement, to further refine MERC's CCOSS. Specifically the Commission will direct MERC to do the following:

- For each installation project, collect data on pipe footage, pipe diameter, and cost;
- Research and, as soon as possible, begin collecting data regarding the retirement of distribution assets at the same project-level detail; and
- In future rate cases, explore the use of this project-specific data in MERC's Zero Intercept CCOSS.

[45] Ex. 35, at 52–54, Schedule JCHM-R3 (Hoffman Malueg Rebuttal).

Similarly, the Commission will decline to adopt the OAG's recommendation to select multiple cost studies to guide the Commission's further analysis. While the Commission has sometimes found it necessary and appropriate to do so, in the current case the Commission is persuaded—as are MERC, the Department, and the Administrative Law Judge—that the Zero Intercept study is the best alternative in the record. Consequently the Commission finds no need to rely on other models as well.

But the Commission's determination in this rate case pertains to *this case*. In MERC's next rate case the Commission will evaluate anew the parties' CCOSSs, and select one or more to guide the Commission's deliberation. To ensure that the Commission receives sufficient studies to evaluate at that time, the Commission will direct MERC to do the following in its next rate case:

- File a Zero Intercept CCOSS and a Minimum Size CCOSS, as proposed by MERC;
- File a Basic System CCOSS, and an Average and Excess CCOSS, as proposed by the OAG; and
- Provide a substantive explanation and justification of its classification and allocation methods when it files its CCOSS.

Finally, the Commission will decline to initiate a generic proceeding to select a CCOSS method for all gas rate cases. Rather, as discussed above, the Commission will address these matters on a case-by-case basis, evaluating the unique circumstances of each utility.

RATE-DESIGN ISSUES

Most of this docket has, thus far, sought to identify and quantify the costs that a prudently managed utility serving MERC's service area would bear. The following sections will address how MERC may recover those costs from its ratepayers and earn a reasonable return on its investment. This process of *rate design* requires the Commission to exercise policy judgment because there are many ways to set rates to enable a utility to recover appropriate revenues.

In designing rates for a natural gas utility, the Commission considers a variety of factors, including the following:[46]

- Equity, justice, and reasonableness, and avoidance of discrimination, unreasonable preference, and unreasonable prejudice;[47]
- Continuity with prior rates to avoid rate shock;
- Revenue stability;
- Economic efficiency;

[46] *See generally* ALJ's Report ¶ 606.

[47] Minn. Stat. §§ 216B.01, .03, .07.

- Encouragement of energy conservation;[48]
- Customers' ability to pay;[49]
- Ease of understanding and administration; and in particular,
- Cost of service.

Estimating the cost to serve any given customer is challenging because a utility will incur different costs to serve different customers, and will incur many costs that benefit multiple customers. Because similar types of customers tend to impose similar types of costs on the system, utilities simplify their analysis by first dividing customers into classes—for example, distinguishing residential customers from commercial or industrial customers. Utilities then attempt to determine the amount of revenues they should recover from each customer class.

XIV. Interclass Revenue Apportionment

A. Introduction

The next step in rate design is to determine the share of the utility's revenue requirement to recover from each type of customer. MERC divides its customers into classes based in part on the customer's characteristics, and in part on the type of service the customer chooses to receive.

MERC distinguishes between *Sales service* and *Transportation service*. Most of MERC's customers buy Sales service. For these customers MERC procures a supply of natural gas, arranges to transport it via interstate pipelines to MERC's service area, distributes the gas to each customer's premises, and resells the gas. In contrast, some large industrial customers buy Transportation service. A Transportation customer buys its own gas supplies and arranges for it to be shipped via interstate pipelines to where those pipelines meet MERC's distribution system, and then pays MERC to transport the gas from that point to the customer's premises.

MERC also distinguishes between *firm*, *interruptible*, and *Joint Service*. MERC acquires both the capacity and the gas supply to provide all the gas required by its firm customers, even during periods of peak demand. Customers who subscribe for interruptible service agree, in exchange for paying a lower price for gas, to stop consuming gas under specified circumstances, such as during periods of peak demand. And customers subscribing for Joint Service are entitled to take a fixed amount of firm service each month, with any excess consumption treated as interruptible service.

MERC also distinguishes among its commercial and industrial customers based on the *amount of gas consumed*—from Small Volume to Super Large Volume. MERC even has a class of very large Flexible Rate Gas customers that are subject to effective competition, and have a credible capacity to bypass MERC's system and secure gas from another source. But for purposes of interclass revenue allocations, the parties analyzed six classes: Residential; Small Commercial and Industrial (SC&I); Large Commercial and Industrial (LC&I); Small Volume Sales (Sm. Vol. Sales); Large Volume Sales (Lg. Vol. Sales); and Transportation (Transport).

---

[48] Minn. Stat. §§ 216B.03, .2401, 216C.05.

[49] Minn. Stat. § 216B.16, subd. 15.

Finally, MERC distinguishes between customers based on their *location*. MERC has long served some customers with gas from the Northern Natural Gas Pipeline (MERC's NNG customers), and other customers with gas from the consolidated Centra, Viking Gas and Great Lakes Gas Pipeline (MERC's Consolidated customers). And in 2015 MERC began serving an additional group of customers in and around the City of Albert Lea using facilities MERC purchased from Interstate Power and Light (MERC's Albert Lea customers).

These areas generate somewhat different costs because MERC has entered into different contracts to secure gas to serve customers in each area. More significant for this case, MERC derives different revenues from the customers in different areas: The Albert Lea area customers, formerly served by IPL, have not experienced a rate increase resulting from a general rate case since 1996.

B. Positions of the Parties

Generally MERC proposed to recover revenues from each customer class based on each class's share of revenues indicated by MERC's CCOSS. But where this would result in large shifts in class allocations, MERC moderated its proposal to mitigate rate shock—especially for MERC's new customers in the Albert Lea region. Specifically, MERC proposed to refrain from allocating to former IPL customers the full amount of the costs that MERC's model associates with serving those customers. Instead, MERC proposes to allocate part of the amount for purposes of the current case, and would propose to allocate the remainder as part of its next rate case.

The Department supported MERC's modified proposal for class revenue allocation.

The OAG recommended a slightly different allocation, designed to further mitigate the share of revenues to be recovered from customers in the Albert Lea region. In particular, the OAG proposed implementing any increase in revenue requirement assigned to the Albert Lea rate area over the course of three rate cases rather than two.

The following table shows MERC's current revenues from each customer class (disaggregated by rate area), and the parties' final proposals for increasing the revenues from each class, assuming the Commission were to approve a revenue increase of 10.15%:

Proposed Revenue Increases (excluding cost of gas)				
	Rate Areas	**Current Revenues ($000s)**	**MERC's proposed increase**	**OAG's proposed increase**
Residential	**NNG**	$51,188	10%	10%
	Consolidated	$8,834	10%	9%
	Albert Lea	$2,406	23%	19%
Total Residential		**$62,428**	**10%**	**10%**
SC&I	**NNG**	$3,382	13%	6%
	Consolidated	$1,081	14%	6%
	Albert Lea	$116	60%	45%
Total SC&I		**$45,792**	**1%**	**1%**
LC&I	**NNG**	$15,847	5%	6%
	Consolidated	$5,016	4%	6%
	Albert Lea	$693	28%	28%
Total LC&I		**$21,556**	**5%**	**6%**
Sm. Vol. Sales	**NNG**	$2,101	14%	15%
	Consolidated	$500	12%	13%
	Albert Lea	$185	38%	38%
Total Sm. Vol. Sales		**$2,786**	**15%**	**16%**
Lg. Vol. Sales	**NNG**	$611	16%	18%
	Consolidated	$184	19%	20%
	Albert Lea	$64	32%	32%
Total Lg. Vol. Sales		**$858**	**18%**	**19%**
Transport	**NNG**	$5,763	16%	22%
	Consolidated	$1,746	14%	20%
	Albert Lea	$97	22%	25%
Total Transport		**$7,606**	**16%**	**21%**
TOTAL		**$99,813**	**10%**	**10%**

C. The Recommendation of the Administrative Law Judge

Comparing the two allocations proposed by the parties, the Administrative Law Judge found that MERC's proposal was more reasonable. First, the Administrative Law Judge noted that MERC's proposal was based on a Zero Intercept CCOSS, which the Administrative Law Judge had found to be the most reasonable cost study in the record. In contrast, the OAG designed its allocation based in part on MERC's cost study, but in part on the OAG's Basic System CCOSS, which the Administrative Law Judge had found to provide a less reliable guide for cost causation. Second, the Administrative Law Judge concluded that MERC offered a more reasonable plan for conforming the rates in the Albert Lea rate area to the rates that MERC will charge in its other rate areas.

D. Commission Action

In choosing between the two proposals in the record for how to apportion MERC's revenue requirement among its customer classes, the Commission concurs with the Administrative Law Judge and the Department's recommendation to adopt MERC's position.

The Commission's judgment in this matter reflects in part its selection of MERC's CCOSS: Because the Commission found that MERC's CCOSS provided a more reliable guide than the OAG's CCOSS, the Commission finds the interclass revenue apportionment based on MERC's CCOSS more reliable than an interclass revenue apportionment developed on some other basis.

Moreover, the Commission finds that where MERC deviated from the results of its CCOSS, it did so for appropriate reasons. MERC's choice to delay allocating the full share of Albert Lea's costs to Albert Lea customers will have the effect of shifting some additional costs to other customers. But by allocating costs to Albert Lea customers more gradually, this apportionment will help avoid rate shock among those customers. And MERC's choice to limit the number of steps required until the Albert Lea customers transition to the same rate structure as MERC's other customers in the same class will appropriately limit the resulting interclass subsidies.

For these reasons, the Commission will approve the interclass revenue apportionment proposed by MERC.

XV. Monthly Customer Charge

A. Introduction

MERC assesses charges to members of each customer class based on a two- or three-part rate. One part consists of a fixed monthly customer charge, designed to recover the fixed costs of serving a customer. Another part consists of a distribution charge that varies with the amount of natural gas a customer uses. And for certain classes of larger customers, MERC also assesses a monthly demand charge reflecting the peak amount of gas the customer uses.

The forecasted sum of the revenues from a class's customer charge, distribution charge, and demand charge must equal the class revenue apportionment. Thus rate design poses a trade-off: the choice to reduce any one component of these charges must result in an increase to another component. For customers that do not pay a separate demand charge—such as residential customers—an increase in the customer charge will have the effect of reducing the volumetric distribution charge, and vice versa.

Traditionally, utilities favor assessing a fixed customer charge to recover some or all of the fixed costs of serving customers. Also, utilities favor increased customer charges to make total bills and revenue collections more stable by reducing the share of a class's revenue requirement to be recovered on the basis of energy consumption, which varies month to month.

In this case, the most salient fact is that most customers in the Albert Lea region have been paying the same distribution charge, but lower customer charges, than have comparable MERC customers outside the Albert Lea area. For example, a Large Volume Interruptible Sales customer in the Albert Lea area pays a monthly customer charge of $14; in the rest of MERC's areas, that customer charge is $185.

B. Positions of the Parties

1. Areas of Agreement

The parties reached broad agreement on a number of issues.

MERC initially proposed to increase the customer charge for many customer classes to recover a larger share of the fixed costs of serving those customers. But the Department and the OAG noted that Albert Lea customers would already face a large increase in their customer charges simply to reach the levels currently paid by MERC's other customers, and that a general increase in customer charges would only compound this problem. So in rebuttal testimony MERC withdrew its proposal to increase customer charges for any customers outside of the Albert Lea area—with one exception: Because the Albert Lea area has no Super Large Volume Interruptible customers, and because MERC was seeking an increase of only about 2%, MERC maintained its proposal to increase the monthly customer charge for this class from $460 to $470. No party contested this recommendation.

All parties also agreed that customers within each customer class should pay the same customer charge. To this end, they agreed that the Transportation customers in the Albert Lea area should begin paying the same customer charges as MERC's other Transportation customers. This would result in increasing customer charges by 41% or less.

However, raising the customer charge on the Albert Lea Sales customers to the level of MERC's other Sales customers would result in increases of 90% or more. All parties agreed that the Commission should refrain from implementing such a large change in the customer charge at one time, and instead should implement this change over two or three rate cases. But the parties disagreed about the details.

2. Areas of Dispute

MERC recommended increasing the customer charges for Sales customers in the Albert Lea area over the course of two rate cases. That is, MERC would set the customer charges for these customers at half the difference between their current rate and the rate charged to other MERC Sales customers. In its next rate case MERC would increase the Albert Lea Sales charges to the same level as MERC's other customers. To this end MERC would commit, in its next rate case, not to seek any increase in the customer charges for its customers outside of the Albert Lea area.

The OAG's recommendation differed from MERC's in two respects.

First, the OAG recommended implementing those changes over the course of three rate cases rather than two. This proposal reflected the OAG's concern that the proposed increases for Residential and Small Commercial & Industrial customers in the Albert Lea area were still too large, resulting in customer charge increases of 30% for Residential customers and 80% for Small Commercial & Industrial customers. These increases would be in addition to the increase in the volumetric charge that these customers will bear due to the growth in MERC's revenue requirement and the shift in revenue apportionment (discussed above). And the OAG argued that the resulting intraclass subsidies would be relatively small.

Moreover, the OAG argued that the fixed customer charge should recover the average fixed costs of adding an additional customer within the customer class, and calculated a range of estimates of those costs; the OAG's recommended customer charges were within this range.

Second, the OAG recommended reducing the customer charge for Small Commercial & Industrial customers outside of the Albert Lea area from $18 to $17, again based on its calculation of the fixed costs of adding an additional customer within the class.

MERC disputed the OAG's calculation of incremental customer costs, arguing that the calculation arbitrarily excluded costs that MERC generally incurs to serve each additional customer.

The Department supported MERC's proposal except that the Department stated that it could support a residential customer charge in the Albert Lea area of either $6.50 (as recommended by the OAG) or $7.50 (as recommended by MERC).

The contested portions of the parties' proposals are as follows:

Disputed Monthly Customer Charges				
	Current Charge	**MERC Proposal**	**Department Proposal**	**OAG Proposal**
Residential - Albert Lea	$5.00	$7.25	$6.50/$7.25	$6.50
Residential - Non-Albert Lea	$9.50	$9.50	$9.50	$9.50
SC&I - Albert Lea	$5.00	$11.50	$11.50	$9.00
SC&I - Non-Albert Lea	$18.00	$18.00	$18.00	$17.00

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that MERC's recommendation, as modified in its rebuttal testimony, would help shift rates closer to cost, as reflected in the Company's CCOSS, but in a gradual manner that would mitigate the risk of rate shock.

While acknowledging that $2.25 reflected a substantial increase in the monthly charge for Residential Albert Lea customers, the Administrative Law Judge reasoned that these customers had enjoyed the benefits of 20 years without a general rate case. The Administrative Law Judge noted that even under MERC's proposal, the Albert Lea customers would be paying a lower customer charge than MERC's other customers—and, indeed, lower than the customer charges approved by the Commission for other gas utilities.

Moreover, the Administrative Law Judge found that the Albert Lea customers were paying less than the cost that MERC bears to serve them, and that prolonging this situation would also prolong the need for other customers to subsidize these customers. The Administrative Law Judge found that MERC's proposal struck an appropriate balance among the competing concerns.

D. Commission Action

Here the primary issue in dispute is not the appropriate magnitude of customer charges, but the timing of their implementation.

Public utilities must not charge rates that are "unreasonably preferential, unreasonably prejudicial, or discriminatory," but must charge rates that are "sufficient, equitable, and consistent in application to a class of consumers."[50] Further, public utilities may not "grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage."[51]

Balancing these concerns, the Commission concurs with the Administrative Law Judge that MERC's final position strikes the appropriate balance between the goals of setting prices to reflect cost; moderating rate shock; and maintaining uniform, nondiscriminatory rates to avoid intraclass subsidies. Again, by limiting the transitional phase to two rate cases, rather than three, the Commission will minimize these subsidies.

The Commission concurs with MERC that the OAG's calculation of customer-specific costs failed to include all the relevant costs. Consequently the Commission is not persuaded of the merits of reducing the customer charge for MERC's Small Commercial & Industrial customers at this time.

In sum, the Commission will adopt the schedule of customer charges as recommended in MERC's rebuttal testimony, recommend by the ALJ, and set forth below:[52]

Customer Class	Albert Lea Area Customers	Other MERC Customers
Residential	$7.25	$9.50
General Service, SC&I	$11.50	$18.00
General Service, LC&I	$25.00	$45.00
Sales, SVI & SVJ	$89.50	$165.00
Sales, LVI & LVJ	$99.50	$185.00
Transport, SVI & SVJ	$280.00	
Transport, LVI & LVJ	$300.00	
Flexible Rate	$300.00	
SLVI	$470.00	

[50] Minn. Stat. § 216B.03.

[51] Minn. Stat. § 216B.07.

[52] ALJ's Report ¶ 649.

Finally, the Commission observes that MERC, while supporting the findings and analysis in the ALJ's Report, noted that the Administrative Law Judge neglected to adopt one aspect of its position: MERC had agreed not to request any increase in the customer charge for various customer classes in its next rate case. Thus MERC asked the Commission to adopt a revised version of ALJ's Report, Finding 658, as follows:

> 658. The Administrative Law Judge does not recommend adopting the OAG's proposal to transition the former IPL customers to the MERC customer charge over the course of three rate cases. The OAG's proposal would result in MERC's non-IPL customers continuing to subsidize MERC's IPL customers over a number of years. Such a long transition would result in unreasonably preferential rates for the former IPL customers who receive the same service and are in the same class of service as MERC's other customers. The Administrative Law Judge recommends instead that the Commission order that the former IPL customers be fully transitioned to MERC customer charges in the Company's next rate case. <u>To allow for a transition period, MERC has agreed to hold Residential, SC&I, LC&I, SVI/SVJ Sales, and LVI/LVJ Sales customer charges unchanged in its next rate case proceeding.</u>

Again, MERC has agreed to conform the customer charges in the Albert Lea area to the customer charges paid by MERC's other customers of the same customer class, but to implement that change over two rate cases. By committing to propose no change in customer charges in its next rate case for its sales customers, other than sales customers in the Albert Lea area, MERC will enable the customer charges in the Albert Lea area to reach the level of customer charges for MERC's other customers. Consistent with this understanding, the Commission will adopt Finding 658 as modified above.

XVI. Revenue-Decoupling Pilot Program

A. Introduction

Under traditional rate design, when ratepayers buy more energy than forecast, they pay higher bills than expected and the utility receives revenues exceeding its costs. Conversely, when ratepayers buy less energy than forecast, they pay lower bills than expected and the utility receives revenues less than its costs. This dynamic produces two adverse consequences. First, the utility and ratepayers both bear the risk that sales will differ from forecast. Second, while the Legislature directs the Commission to encourage energy conservation and efficiency, this rate design creates a disincentive for utilities to pursue policies that would result in decreased energy sales.

Revenue decoupling is a type of rate design intended to align the utility's interests with the public's interest by severing the connection between energy sales and net revenue. Consistent with statute, the Commission has established standards for decoupling mechanisms that would operate "without adversely affecting utility ratepayers,"[53] and has authorized some three-year pilot programs implementing decoupling.[54]

The Commission previously authorized MERC to implement a pilot revenue-decoupling mechanism (RDM) for its Residential and Small Commercial & Industrial customers,[55] and later granted MERC's request to extend the program with the instruction that MERC address the matter in this rate case.[56]

MERC's revenue-decoupling mechanism generally works as follows: The Commission has approved an interclass revenue apportionment for non-gas costs. At the end of each year, MERC calculates the revenues generated by each applicable customer class (excluding revenues reflecting the cost of the gas itself), and compares them to each class's revenue requirements. For each class, the Company then adjusts future delivery charges to return any surplus to, or recover any deficit from, members of the same class. To mitigate any perceived financial risk arising from this program, MERC caps the size of any adjustment arising from the program at 10%. Finally, MERC must file reports annually on the status of its program, including a final evaluation report at the end of the pilot period.

B. Positions of the Parties

In the current case MERC proposed to extend the pilot program for another three years. The Department generally supported MERC's proposal, but recommended that the Commission direct MERC to provide supplementary analyses in the future, as follows:

- In its next rate case, MERC should explain why extending decoupling to all classes with more than 50 customers is not reasonable.

- If MERC seeks a further extension in its next rate case or at the end of its decoupling pilot program, MERC should address evidence showing that energy savings achieved by the Residential class has declined since MERC's decoupling program began.

In contrast, the OAG stated that the program should be cancelled—unless the Commission modified it in three ways.

---

[53] Minn. Stat. § 216B.2412, subd. 2. *See In the Matter of a Commission Investigation Into the Establishment of Criteria and Standards for the Decoupling of Energy Sales from Revenues*, Docket No. E,G-999/CI-08-132, Order Establishing Criteria and Standards to be Utilized in Pilot Proposals for Revenue Decoupling (June 19, 2009).

[54] Minn. Stat. § 216B.2412, subd. 3.

[55] 2010 MERC Rate Case Order, at 12–15.

[56] *See* Docket No. G-011/GR-10-977, Order (August 11, 2015).

First, the OAG argued that MERC should have to implement decoupling for all customer classes with at least 50 customers. While MERC argued that its large customer classes have too few customers to participate in decoupling, the OAG stated that MERC provided no quantitative analysis to determine how many customers a class must have before it can be decoupled. The OAG found arguments against implementing decoupling in classes with fewer than ten members, but no objections to classes with 50 or more members.

Second, the OAG argued that MERC should have to forgo implementing any surcharge if it cannot reduce its annual energy sales by at least 1.2% through its Conservation Improvement Program (CIP). Because MERC justified its decoupling program as a means to reduce disincentives for conservation, the OAG argued that MERC should have to demonstrate its accomplishments in order to receive the benefits of the program. The OAG selected a savings level of 1.2% based on target levels that the OAG and the Department recommend for demand-side management programs operated by gas utilities.

Third, the OAG argued that MERC should have to forgo any increase in the customer charges for the customers in the decoupling program—members of Residential and Small Commercial & Industrial classes. The OAG explained that any increase in the customer charge results in a decrease in the distribution charge—that is, the charge per unit of gas consumed—and that higher distribution charges would help deter consumption. Consequently, the OAG argued that increasing the customer charge would tend to undermine the conservation goals for which MERC adopted revenue decoupling in the first place.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended granting MERC's request to continue the pilot revenue-decoupling program for another three years.

Regarding the OAG's proposed condition that MERC refrain from increasing the customer charges for the Residential and Small Commercial and Industrial classes, the Administrative Law Judge noted that she would in fact recommend holding customer charges unchanged for the great majority of MERC's customers.

Regarding the OAG's other conditions—requiring MERC to extend decoupling to all of its customer classes with 50 or more members, and to forgo decoupling surcharges if MERC fails to achieve specified conservation goals—the Administrative Law Judge noted that the Commission had declined to adopt such conditions in the past. Consequently the Administrative Law Judge declined to adopt these conditions here. But the Administrative Law Judge did recommend adopting the Department's proposals to direct MERC to provide further analyses of these issues in the future.

D. Commission Action

The Commission concurs with the Administrative Law Judge, and will therefore grant MERC's request to continue the pilot revenue-decoupling mechanism for another three years. To this end, the Commission will direct MERC to make a compliance filing 30 days after the final order in this docket that includes language to revise its tariffs regarding its pilot revenue-decoupling program.

The OAG recommended that the Commission reject MERC's proposed program extension unless it incorporates three conditions. The Commission will decline to adopt these conditions at this time. With respect to the OAG's recommendation that the Commission require MERC to forgo any increase in customer charges, the Commission has already discussed its reasons for maintaining the current customer charge levels for most customers. But countervailing considerations of equity and cost causation prompt the Commission to approve gradual increases to other customer charges.

Regarding the OAG's other conditions, the Commission does not find a sufficient record to support requiring MERC to extend decoupling to all of its customer classes with 50 or more members, and to forgo decoupling surcharges if MERC fails to achieve specified conservation goals. But even if the Commission were to eventually embrace these alleged improvements, the Commission is not persuaded that MERC's current program should be terminated in their absence. In short, MERC's program remains a pilot program; the fact that it may not yet have achieved its final form is not a reason to abandon it.

But while the Commission finds that it has sufficient information to support maintaining MERC's pilot decoupling program, the Commission also concurs with the Administrative Law Judge that MERC should explore the issues that the OAG (and the Department) raised. Indeed, MERC asked the Commission to adopt the Administrative Law Judge's Finding 674 modified to clarify that MERC should address these concerns:

> 674. However, the Administrative Law Judge agrees with the Department and the OAG that MERC should be required in its next rate case to demonstrate why extending decoupling to all customer classes is not reasonable. The Administrative Law Judge also agrees with the Department that MERC should be required in its next rate case ~~to address evidence showing Residential energy savings has decreased since inception of the decoupling pilot program.~~ <u>or at the end of its decoupling pilot to demonstrate why continuing its RDM is reasonable given that its Residential energy savings have fallen, not increased.</u>

Because the Commission agrees with MERC's suggestion, it will adopt the Administrative Law Judge's Finding 674 with MERC's proposed modifications. And the Commission will go further.

First, the Commission will adopt the recommendation to require MERC to demonstrate why it should not extend its decoupling program to other customer classes. To this end, the Commission will do the following:

- Direct MERC to include in its annual decoupling filings an analysis of the financial consequences for ratepayers and MERC of extending the decoupling program to all customer classes with more than 50 customers;

- Permit MERC to include in its annual decoupling filings an analysis of the financial consequences of extending its decoupling program to any other combination of customer classes; and

- Direct MERC, in its next rate case, to demonstrate why extending its decoupling program to other rate classes with more than 50 members would not be reasonable.

Second, the Commission will adopt the recommendation to require MERC to address the fact that the levels of conservation achieved by MERC's Residential class have declined since the program took effect. To this end the Commission will do the following:

- Direct MERC to include in its annual decoupling filings an analysis demonstrating the reasonableness of maintaining MERC's decoupling program given evidence that the level of savings generated by the Residential customer class has declined while the program has been in effect;

- Direct MERC to include in its annual decoupling filings (1) data showing its average CIP savings for the previous five years compared to the savings of its most recent complete year, and (2) an explanation for any differences in the CIP savings, including the likely impact of decoupling; and

- Direct MERC to include in its decoupling evaluation report or in its initial filing of its next rate case an analysis demonstrating the reasonableness of maintaining MERC's decoupling program given the evidence that the level of savings generated by the Residential customer class has declined while the program has been in effect.

This additional information will place all parties in a position to better evaluate MERC's pilot decoupling program when it next comes before the Commission.

XVII. Transportation Imbalance

A. Introduction

Transportation customers must secure their own supply of gas. They may do this themselves, or hire a third party such as Constellation NewEnergy-Gas Division, LLC (Constellation) to do it. Constellation offers to buy natural gas on behalf of Transportation customers and then arranges for it to be shipped via interstate pipelines to MERC's facilities. Each Transportation customer could then contract for MERC's interruptible Transportation services to move the gas to the customer's facilities, or Constellation could contract with MERC on the customer's behalf.

Interstate pipelines such as Northern Natural Gas Pipeline (NNG) ship gas owned by a variety of parties who insert and extract the gas at various points along the pipeline. To manage this system, NNG imposes imbalance penalties on a customer when the amount of gas the customer takes out of the pipeline on a given day differs from the amount the customer put in. Similarly, MERC imposes imbalance penalties on customers using its own system, using the same imbalance process and penalty structure used by NNG.

When NNG finds that demand for gas on its system exceeds the currently available supply—triggering a Critical Day, or the declaration of an Operational Flow Order—NNG may direct interruptible customers to curtail gas consumption in order to preserve the supply available to firm customers. Likewise, MERC may direct interruptible customers to curtail gas consumption on MERC's system in order to ensure a sufficient gas supply for firm customers. But when supply and demand are brought back into balance, MERC then restores to interruptible customers the amount of their gas that MERC used in the interim to serve the firm customers, or the cash equivalent, as specified in tariff.

These curtailments have a variety of consequences for interruptible customers. In particular, they may leave an interruptible customer in an imbalance position, having nominated gas to be delivered to MERC's system but being forbidden to then take the gas off MERC's system. Also, during periods when demand exceeds supply, the value of gas increases. This price increase is not reflected when MERC provides compensatory gas after the shortage has abated.

B. Positions of the Parties

Constellation proposed changes to MERC's tariffs governing these matters: If an interruptible customer cannot receive its gas due to a Critical Day or an Operational Flow Order, Constellation proposed that the amount of compensation that customer would receive would reflect the price of gas at the time MERC gave notice to its interruptible customers—that is, the price of gas during the shortage.[57] To aid this analysis, Constellation further proposed that MERC post on its website a variety of details about the timing and circumstances of the curtailment event.

MERC opposed this proposal, arguing that its current policy is fair and simply echoes the federally approved policies of NNG. And MERC argued that posting details of curtailment events on its website would be unnecessary—because MERC contacts the interrupted customers individually—and could provoke needless customer confusion.

MERC identified four strategies available to an interrupted Transportation customer. But Constellation argued that the alternatives identified by MERC were unworkable and would not provide the compensation Constellation seeks.

MERC expressed concern that Constellation's proposal, by preserving the value of gas during a period of scarcity, would give sophisticated market participants an incentive to manipulate the system to gain a windfall. Indeed, MERC argued that one advantage of designing its imbalance policies to match NNG's policies is to minimize a party's opportunity to exploit differences in the policies.[58] But Constellation denied that sophisticated parties would be able to manipulate its proposed tariff language to achieve any benefit other than the benefit of owning a supply of natural gas during a time of scarcity.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed with MERC's assessment. She found that MERC's current tariffs provided a fair and appropriate process for managing imbalances and curtailments, that MERC offered alternatives for curtailed customers to pursue, and that there was no reason to require MERC to gather and post details about curtailments on its website.

[57] Specifically, Constellation proposed a price equal to the price of gas at the time MERC provided notice its customers of the NNG Critical Day as reported in Platt's Gas Daily as "Midpoint for Chicago Citygates" under the Citygates section of Platts Gas Daily plus 10%. Ex. 200, at 14–15 (Sorenson Direct).

[58] Evid. Hr'g Tr. Vol. 1, at 156 (Sorenson cross-examination).

D. Commission Action

The Commission concurs with MERC and the Administrative Law Judge. MERC's tariffs governing imbalances are appropriately designed to manage the competing demands on its system during times of curtailment. Because these provisions are well designed to address MERC's real and unavoidable needs, the Commission finds them to be reasonable—and finds Constellation's proposal to change these policies to be unnecessary.

The record does not demonstrate that MERC's current tariffs deprive interruptible Transportation customers of any benefits to which they are entitled. The primary consequence of Constellation's proposal would be to permit these customers to reap a windfall at the expense of other ratepayers. The Commission finds no basis for the view that these customers are entitled to this benefit.

As the Administrative Law Judge observed, MERC's tariffs already provide a number of alternatives for Transportation customers in the event a curtailment is called. The Commission is not persuaded that further relief is warranted.

Finally, the Commission concurs with the Administrative Law Judge that, since customers receive direct notice of any curtailment events, providing additional and detailed notice via the web carries only the potential for confusion.[59] For these reasons, the Commission will decline to adopt Constellation's proposal.

XVIII. Joint Rate Service

A. Introduction

Joint Rate Service permits small-volume, large-volume, and super-large-volume interruptible Sales and Transportation customers to switch part or all of their interruptible service to firm service for a year.

MERC bears more cost to provide firm service than interruptible service, and the rates for these services reflect this difference. Joint Rate Service, a hybrid of the two, should reflect some intermediate level of cost. Questions arose in MERC's last rate case about how MERC calculated the appropriate price for its Joint Rate Service, and whether it was effectively being subsidized by other services.[60]

B. Positions of the Parties

In this docket MERC proposed to alter its Joint Rate Service to address various concerns, including concerns about

- the size of the premium MERC charges for Joint Rate Service;
- the cost of gas applied to load designated as firm by Joint Rate Service customers; and

[59] *See* Ex. 39, at 51 (Lee Rebuttal).

[60] *See* Docket No. G-011/GR-13-617, Order (May 12, 2015).

- application of the distribution charge for interruptible service, rather than the higher charge for firm service.

MERC proposed to revise its billing method for applying the non-gas portion of the Daily Firm Capacity (DFC) charge (the margin portion), as well as its method of calculating and applying the gas-cost portion of the DFC charge. Combined, these changes are intended to create a consistent billing method for calculating the non-margin and margin portions of DFC charges, without altering the total cost to the customer.

While the Department ultimately recommended that the Commission approve MERC's proposed changes, questions remained about the possibility for cross-subsidy.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended approval of MERC's proposed changes. No party opposed the Administrative Law Judge's recommendation, but MERC asked to clarify her Finding 760 as follows:

> 760. In MERC's last rate case, Docket No. G-011/GR-13-617, issues were raised related to the concern that MERC's Joint Service customers may be subsidized by MERC's general sales customers. To address these concerns, MERC proposed to charge Joint Service customers the Firm Demand cost per therm rate currently charged to General Service customers for the <u>non-margin (gas cost)</u> firm portion of their Joint Service.

Subsequently MERC proposed that the Commission initiate a separate docket to address any unresolved questions, and that the results of that docket be implemented within the context of MERC's next rate case.

D. Commission Action

The Commission concurs with the Administrative Law Judge and the Department that MERC's proposed changes are well designed to address some of the concerns about cross-subsidy. Consequently the Commission will approve MERC's proposed changes to its Joint Rate Service. The Commission also agrees with MERC's proposed clarification and therefore will adopt Finding 760 modified as set forth above.

The Commission also agrees that parties should strive to resolve the outstanding points of dispute for implementation in MERC's next rate case. But the Commission is not persuaded that this matter warrants a separate docket.

Rather, the Commission will direct MERC to provide in its next rate case an analysis to fully evaluate the allocation of demand costs in MERC's Joint Rate Service. This analysis should include a proposal for how the Class-Cost-of-Service Studies should reflect the relevant costs, and the appropriate DFC-charge calculations.

FINANCIAL SCHEDULES AND COMPLIANCE

XIX. Overall Financial Schedules

A. Gross Revenue Deficiency

The above Commission findings and conclusions result in a Minnesota-jurisdictional total gross revenue deficiency of $6,775,462, as shown below:

Revenue Deficiency – Minnesota Jurisdiction
Test Year Ending December 31, 2016

Description	MERC - MN	
Average Rate Base	$	234,395,222
Rate of Return		6.8842%
Required Operating Income	$	16,136,236
Operating Income	$	12,157,691
Income Deficiency	$	3,978,545
Gross Revenue Conversion Factor		1.7030
Gross Revenue Deficiency	$	6,775,462

B. Rate-Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the test year is $234,395,222, as shown below:

Rate-Base Summary – Minnesota Jurisdiction
Test Year Ending December 31, 2016

Description	MERC-MN	
PLANT IN SERVICE		
Energy	$	1,299,392
Transmission	$	14,009,744
Distribution	$	440,584,475
Customer	$	8,509,545
Total Plant In Service	$	464,403,156
RESERVE FOR DEPRECIATION		
Energy	$	380,665
Transmission	$	4,652,257
Distribution	$	185,466,361

Customer	$	2,492,926
Total Reserve For Depreciation	$	192,992,209
NET PLANT IN SERVICE		
Energy	$	918,727
Transmission	$	9,357,487
Distribution	$	255,118,114
Customer	$	6,016,619
Total Net Plant In Service	$	271,410,947
Construction Work in Progress	$	-
LESS: Customer Advances	$	-
LESS: Plant Deferred Income Taxes	$	50,563,100
Working Capital:		
Cash Working Capital	$	(2,896,178)
Deferred Taxes Other than Plant	$	4,405,114
Non-Utility Adjustment	$	(1,118,966)
Plant Adjustment	$	(5,004)
Subtotal	$	384,966
Materials and Supplies	$	189,866
Gas Storage Inventory	$	6,486,821
Prepayments	$	476,778
Regulatory Assets/Liabilities	$	6,008,944
Subtotal	$	13,162,409
TOTAL AVERAGE RATE BASE	$	234,395,222

C. Operating-Income Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota-jurisdictional operating income for the test year under present rates is $12,157,691, as shown below:

Operating-Income Summary – Minnesota Jurisdiction
Test Year Ending December 31, 2016

Description		MERC-MN
UTILITY OPERATING REVENUES		
Retail Revenue	$	228,101,665
Late Payment Revenue	$	750,000
Other Operating Revenue	$	263,854
Total Operating Revenues	$	229,115,519
UTILITY EXPENSES		
Purchased Cost of Gas	$	128,288,528
Other Production	$	666,013
Gas Supply	$	849,233
Transmission	$	36,762
Distribution	$	20,052,570
Customer Accounting	$	8,850,305
Customer Service & Information	$	1,239,817
Administrative & General	$	18,148,894
Total Operating Expenses	$	178,132,122
Amortizations	$	12,405,681
Depreciation	$	11,494,009
Taxes Other than Income Taxes	$	9,880,229
Other Interest Expense	$	297
Total Depreciation & Other Taxes	$	33,780,216
Federal Income Tax	$	3,908,316
State Income Tax (MN & MI)	$	633,444
Interest Synch	$	503,730
Total Income Taxes	$	5,045,490
Total Expenses	$	216,957,828
Net Income	$	12,157,691

XX. 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 the filing, apart from the proposed customer notice.

ORDER

1. Minnesota Energy Resources Corporation (MERC or the Company) is entitled to increase Minnesota-jurisdictional revenues by $6,775,462 to produce jurisdictional total gross revenue of $235,890,981 for the test year ending December 31, 2016.

2. The Commission accepts, adopts, and incorporates the findings, conclusions, and recommendations of the Administrative Law Judge, except as set forth herein.

3. The Commission clarifies that (1) the 2016 former-manufactured-gas-plant costs will be deferred and amortized rather than expensed in the test year; and (2) MERC's post-2014 former-manufactured-gas-plant cleanup costs will be subject to review for prudence and reasonableness.

4. The Commission confirms that MERC's addition of $5 million to the deferred former-manufactured-gas-plant accounts is unsupported and would be unreasonable to include in rate base at this time.

5. MERC shall remove the following six non-employee benefits regulatory asset and liability accounts from rate base: (1) Account 182015 Reg Asset-Short Term; (2) Account 182016 Reg Asset-Derivatives-Current; (3) 182517 Reg Asset-ST Offset; (4) Account 186390 Labor Loader; (5) Account 254015 Reg Liabilities Derivatives Long Term; and (6) Account 254317 Reg Liab-Short Term Offset.

6. MERC shall exclude the nine regulatory asset and liability accounts identified in ALJ Finding 221 from rate base, and a corresponding adjustment shall be made to deferred taxes.

7. MERC shall apply the 2015 percentage of actual bad-debt expense over tariffed revenues of 0.459362% to the approximate Commission-approved test-year tariffed revenues, reduced by the updated cost of gas, and (including) the approximate approved revenue deficiency.

8. MERC shall provide the following information with its initial filing of its next rate case:

    a. An update on the decision process for WEC legacy utilities to implement the ICE system, fully justifying any decision for the WEC legacy utilities not to use ICE;

b. If a process has been implemented to explore the idea, or an actual timeline has been established for WEC legacy utilities to adopt ICE, MERC shall provide a detailed discussion of the status, along with a proposal to reimburse Minnesota ratepayers for their share of the ICE system (deferred and ongoing costs); and

c. If MERC does not provide this information in its initial filing in its next rate case, the initial rate-case filing shall be considered incomplete.

9. In the event that WEC decides to implement the ICE system for its WEC legacy utilities prior to MERC filing its next rate case, MERC shall make a filing within 30 days of such a decision, which shall also be no less than 12 months before initial implementation for WEC legacy utilities. Approval by the WEC board of directors shall be considered the point of decision and will trigger the start of the 30 days. The filing should provide details of WEC's implementation plans and a proposal for adjusting the costs paid by MERC's customers for the ICE system to ensure the costs paid by MERC's customers are reasonable. If such a filing is made prior to the next rate case, the Commission can determine, at that time, whether to revise the contents of the filing to be made by MERC in its next case, as discussed above.

10. MERC may recover costs of the ICE project based on MERC's share (approximately $9.84 million) of the updated total ICE project budget.

11. MERC shall refund $500,000 from the ICE program budget to ratepayers for 2016. On an annual basis starting in 2017, MERC shall place $500,000 from ratepayers into an account.

a. By February 2017 MERC shall develop a tool or survey to measure the effectiveness over time of the ICE project as it relates to the customer services that were intended to be improved by the project. Any survey, consultant, program, or tool to measure project effectiveness must be adopted in consultation with the Department and the OAG.

b. The Company, after consultation with the Department and the OAG, shall set annual ICE-project customer-service benchmarks to be reached by the end of 2017. The Company may modify these benchmarks and shall report annually unless the Commission determines ongoing monitoring is no longer necessary and that the $500,000 no longer needs to be set aside as a performance incentive.

c. The Company shall report performance towards these benchmarks annually at the same time they do their service-quality reporting. At that time the Commission will determine whether the benchmarks for retention of the $500,000 have been met.

12. Regarding Class-Cost-of-Service Studies (CCOSSs), MERC shall do the following:

a. In preparation for MERC's next CCOSS, MERC shall

   i. Collect project-specific data on installation footage, pipe diameter, and cost;

   ii. Research and, as soon as possible, begin collection of distribution-asset retirement at the same project-level detail; and

   iii. Explore the use of this project-specific data in its Zero Intercept CCOSS in future rate-case filings.

b. In MERC's next rate case, MERC shall

   i. Provide a substantive explanation and justification of its classification and allocation methods when it files its CCOSS in the next rate case.

   ii. File CCOSSs using the following methods:

   - Average and Excess
   - Basic System
   - Minimum Size
   - Zero Intercept

13. The Commission adopts MERC's recommended interclass revenue apportionment.

14. Regarding customer charges,

a. MERC shall implement the following schedule of customer charges:

Customer Class	**Albert Lea Area Customers**	**Other MERC Customers**
Residential	$7.25	$9.50
General Service, SC&I	$11.50	$18.00
General Service, LC&I	$25.00	$45.00
Sales, SVI & SVJ	$89.50	$165.00
Sales, LVI & LVJ	$99.50	$185.00
Transport, SVI & SVJ	$280.00	
Transport, LVI & LVJ	$300.00	
Flexible Rate	$300.00	
SLVI	$470.00	

b. In its next rate case, MERC shall propose to conform the customer charges in its Albert Lea area to the current customer charges assessed to its other customers.

c. The Commission adopts Finding 658 of the ALJ's Report, modified as follows:

> 658. The Administrative Law Judge does not recommend adopting the OAG's proposal to transition the former IPL customers to the MERC customer charge over the course of three rate cases. The OAG's proposal would result in MERC's non-IPL customers continuing to subsidize MERC's IPL customers over a number of years. Such a long transition would result in unreasonably preferential rates for the former IPL customers who receive the same service and are in the same class of service as MERC's other customers. The Administrative Law Judge recommends instead that the Commission order that the former IPL customers be fully transitioned to MERC customer charges in the Company's next rate case.<u> To allow for a transition period, MERC has agreed to hold Residential, SC&I, LC&I, SVI/SVJ Sales, and LVI/LVJ Sales customer charges unchanged in its next rate case proceeding.</u>

15. Regarding revenue decoupling:

a. The Commission extends MERC's pilot revenue-decoupling program for another three years.

b. Within 30 days of the final order in this docket, MERC shall make a compliance filing that includes language to revise its tariffs regarding its pilot revenue-decoupling program.

c. MERC shall address the merits of extending its revenue-decoupling mechanism to other customer classes as follows:

i. In its annual decoupling filings, MERC shall include an analysis of the financial consequences for ratepayers and MERC of extending the decoupling program to all customer classes with more than 50 customers. MERC may also include an analysis of the financial consequences of extending its decoupling program to any other combination of customer classes.

ii. In its next rate case, MERC shall demonstrate why extending its decoupling program to other rate classes with more than 50 members would not be reasonable.

d. MERC shall address the decline in energy conservation from the Residential class as follows:

i. In its annual decoupling filings, MERC shall include an analysis demonstrating the reasonableness of maintaining MERC's decoupling program given evidence that the level of savings generated by the Residential customer class has declined while the program has been in effect. MERC shall include (1) data showing its average Conservation Improvement Program (CIP) savings for the previous five years compared to the savings of its most recent complete year, and (2) an explanation for any differences in the CIP savings, including the likely impact of decoupling.

ii. In its decoupling evaluation report or in its initial filing of its next rate case, MERC shall include an analysis demonstrating the reasonableness of maintaining MERC's decoupling program given the evidence that the level of savings generated by the Residential customer class has declined while the program has been in effect.

iii. The Commission adopts the ALJ's Report, Finding 674, as modified below:

674. However, the Administrative Law Judge agrees with the Department and the OAG that MERC should be required in its next rate case to demonstrate why extending decoupling to all customer classes is not reasonable. The Administrative Law Judge also agrees with the Department that MERC should be required in its next rate case ~~to address evidence showing Residential energy savings has decreased since inception of the decoupling pilot program.~~ <u>or at the end of its decoupling pilot to demonstrate why continuing its RDM is reasonable given that its Residential energy savings have fallen, not increased.</u>

16. Regarding MERC's Joint Rate Service:

a. The Commission adopts Finding 760 of the ALJ's Report modified as follows:

760. In MERC's last rate case, Docket No. G-011/GR-13-617, issues were raised related to the concern that MERC's joint service customers may be subsidized by MERC's general sales customers. To address these concerns, MERC proposed to charge Joint Service customers the Firm Demand cost per therm rate currently charged to General Service customers for the <u>non-margin (gas cost)</u> firm portion of their joint service.

b. In its next rate case MERC shall provide an analysis to fully evaluate the allocation of demand costs in its Joint Rate Service. This analysis shall include a proposal for an appropriate CCOSS allocation and daily firm capacity (DFC) charge calculations.

17. MERC shall continue its farm-tap safety inspection program and shall

    a. Continue to send farm-tap safety and information brochures to new farm-tap customers before they take service and to all existing farm customers annually;

    b. Continue to file annual reports on its farm-tap inspection program on or before April 1 of each year; and

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

18. The Commission approves the uncontested tariff amendments proposed by MERC in this proceeding to clarify the applicable rules and processes governing Transportation service, to require Transportation customers to install telemetry equipment before receiving service, to allow authorized parties to request up to 24 months of nonresidential customer-usage history at no charge, and to otherwise amend its tariff to reflect the decisions made in this proceeding.

19. Within 30 days of the date of this order, the Company shall make the following compliance filings:

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

        i. Breakdown of Total Operating Revenues by type;

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

            1. Total revenue by customer class;
            2. Total number of customers, the customer charge, and total customer-charge revenue by customer class; and
            3. For each customer class, the total number of 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.

        iii. Revised tariff sheets incorporating authorized rate-design decisions; and

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

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

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

d. A computation of the Conservation Cost Recovery Charge (CCRC) based on the decisions made herein. A schedule detailing the CIP tracker balance at the beginning of interim rates, the revenues (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.

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

20. Persons wishing to comment on the compliance filings shall do so within 30 days of the date they are filed. Comments are not invited on the proposed customer notice.

21. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

This document can be made available in alternative formats (e.g., large print or audio) by calling 651.296.0406 (voice). Persons with hearing loss or speech disabilities may call us through their preferred Telecommunications Relay Service.