BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben Chair
Valerie Means Commissioner
Matthew Schuerger Commissioner
Joseph K. Sullivan Commissioner
John A. Tuma Commissioner

In the Matter of the Petition by Great Plains Natural Gas Company (Great Plains or the Company) for Authority to Increase Natural Gas Rates in Minnesota

ISSUE DATE: October 26, 2020
DOCKET NO. G-004/GR-19-511
FINDINGS OF FACT, CONCLUSIONS, AND ORDER

PROCEDURAL HISTORY

I. Initial Filings and Orders

On September 27, 2019, Great Plains Natural Gas Company (Great Plains or the Company) filed this general rate case seeking an annual rate increase of $3,639,918 million, or 15.2%. The filing included a proposed interim-rate schedule.

On November 22, 2019, the Commission issued three orders in this case:

- an order finding the rate-case filing substantially complete and suspending the proposed final rates;
- a notice and order for hearing referring the case to the Office of Administrative Hearings for contested-case proceedings; and
- an order setting interim rates for the period during which the rate case was being resolved.

II. The Parties and Their Representatives

The following parties appeared in this case:

- Great Plains Natural Gas Company, represented by Brian M. Meloy, Stinson, LLP.
- Minnesota Department of Commerce (the Department), represented by Linda S. Jensen and Richard Dornfeld, Assistant Attorneys General.
III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Ann C. O’Reilly to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings. The ALJ held an evidentiary hearing in Saint Paul on March 10, 2020. After the hearing, the parties filed initial briefs, reply briefs, and proposed findings of fact and conclusions of law. The parties filed joint proposed findings on undisputed issues.

The ALJ also held two public hearings in the case on February 24, 2020—one in Marshall and one in Fergus Falls.

IV. Public Comments

The Administrative Law Judge held two public hearings, where the Company, the Department, the OAG, and the Commission’s staff were available to make presentations and field questions from members of the public.

The ALJ summarized the public comments in her report.\(^1\) No written public comments on the proposed increase were received.

V. Proceedings Before the Commission

On June 30, 2020, 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, and the OAG.

On August 4 and August 6, 2020, the Commission heard oral argument from and asked questions of the parties. On August 6, 2020, 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

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1 ALJ’s Report, Findings ¶¶ 62–69.
2 Minn. Stat. § 216B.16, subds. 4, 5, and 6.
interests of the utility companies, their shareholders, and their customers,” citing Minn. Stat. § 216B.16, subd. 6.³ That statute is set forth in pertinent part below:

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

B. The Commission’s Role

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

³ In re Interstate Power Co., 574 N.W.2d 408, 411 (Minn. 1998).
⁴ In re N. States Power Co., 416 N.W.2d 719, 722–23 (Minn. 1987) (citation omitted).
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. Any doubt as to reasonableness is to be resolved in favor of the consumer.

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. Minn. Stat. § 216B.16, subd. 4 (1986). “Preponderance of the evidence” is defined for ratemaking proceedings as “whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission’s statutory responsibility to enforce the state’s public policy that retail consumers of utility services shall be furnished such services at reasonable rates.”

II. Rate Case Overview

Great Plains seeks a natural gas rate increase of $3,639,918, or an increase of 15.2% annually, together with a proposal to incorporate into base rates a revenue requirement established in the Company’s Gas Utility Infrastructure Cost (GUIC) rider. The combined impact to customers would be a “new” rate increase of $2,860,839, representing a 12% increase in revenues.

The Company’s proposed rate increase is based on a test year comprising actual financial information from calendar year 2018, adjusted for known and measurable changes through year-end 2019, and projected through December 31, 2020.

As part of its proposal, the Company proposed to increase fixed monthly charges and to shift more revenue responsibility to its residential classes. The ALJ found that the impact of the proposed rate changes, by customer class, would be:

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5 Minn. Stat. § 216B.16, subd. 4.
6 Minn. Stat. § 216B.03.
7 In re Minn. Power & Light Co., 435 N.W.2d 550, 554 (Minn. App. 1989) (citation omitted).
According to the Company, a typical residential customer using 81 dekatherms annually will see an increase of $7.05 per month, or $84.60 per year, over current rates.

### III. Summary of the Issues

Many initially contested issues were resolved in the course of proceedings before the ALJ. The Administrative Law Judge found that the resolutions reached by the parties were reasonable and supported by record evidence; she recommended accepting them. The Commission concurs. Other issues remained contested. The following issues either were contested or otherwise require discussion.

**Financial Issues**

- **Industry Dues**—Should the Commission allow recovery of dues paid by the Company to the Minnesota Utility Investors Association and the Edison Electric Institute?
- **Incentive Compensation**—Should the Company be required to file an annual report for the purpose of tracking any unpaid incentive compensation amounts and returning those amounts to ratepayers?
- **Rate Case Expense**—Should the Company be required to track and apply any over-recovery of costs as a credit to the Company’s revenue requirement in its next rate case?

**Cost-of-Capital Issues**

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

**Class-Cost-of-Service-Study (CCOSS) Issues**

- **CCOSS**—What action should the Commission take, if any, with respect to the Company’s Class Cost of Service Study in this case? What action should the Commission take regarding the Company’s CCOSS for its next case?

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8 ALJ’s Report, Conclusions of Law ¶ 11.
Sales Forecast

- **Historical customer data**—Should the Company be required to retain historical customer consumption data for the purpose of informing future rate decisions?

Rate-Design Issues

- **Fixed Customer Charges**—At what level should the Commission set the fixed monthly charges?
- **Fixed Charge Bill Calculation**—Should the Company bill the customer service charge as a daily amount for residential, small firm, and large firm customers.

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 one formal evidentiary hearing and two public hearings. She reviewed the testimony of 27 expert witnesses and related hearing exhibits.

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 some 466 findings of fact and conclusions of law and made recommendations on 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 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. Organizational Dues

A. Introduction

The Company’s 2020 test-year revenue requirement included $41,872 for dues paid to various trade organizations. The Commission generally reviews organizational dues included in a utility’s revenue requirement to determine whether ratepayers derive a benefit from the utility’s membership in the organization or the membership is reasonably related to providing safe, reliable utility service. In this docket, the Department recommended disallowing $11,500 for dues
paid to the Minnesota Utility Investors Association (MN Utility Investors), and OAG recommended disallowing the MN Utility Investors dues as well as $464 in dues paid to the Edison Electric Institute (Edison Electric).

B. Positions of the Parties

1. Great Plains

Great Plains argued that it should be allowed to recover a portion of the dues paid to MN Utility Investors because this organization “focuses on legislation and regulatory policy that impacts utilities and, directly and indirectly, impacts utility customers.”9 The Company noted that it had already excluded 35 percent of the MN Utility Investors expense related to lobbying, and “further exclusion would harm the Company.”10 Great Plains argued that it should be allowed to recover at least 50 percent of this expense in recognition of ratepayer benefits.

In justifying recovery of dues paid to Edison Electric, Great Plains explained that it participates in Edison Electric’s Utility Solid Waste Activities Group (Solid Waste Group), “which is responsible for addressing solid and hazardous waste issues on behalf of the utility industry and is utilized by Great Plains in a number of ways specifically for its natural gas operations.”11

2. Department

The Department recommended disallowance of MN Utility Investors dues, arguing that this association represents the interests of utility shareholders and does not benefit ratepayers. The Department noted that by the Company’s own description, the principal objective of MN Utility Investors is to “enhance the voice and impact of utility shareholders in the development of federal, regional and state legislative and regulatory policy.”12

The Department acknowledged that certain investor relations expenses, such as shareholder record keeping and recruiting equity capital, can benefit ratepayers because obtaining new investors helps keep utility financing costs reasonable. The Department explained that the Commission has allowed 50 percent recovery of investor relations expenses when the utility does not provide a detailed breakdown of the individual costs in this category. But the Department argued that the dues paid to MN Utility Investors do not meet the standard for recoverable investor relations expenses because “the activities of [MN Utility Investors] do not enhance or facilitate equity funding specifically for Great Plains. [MN Utility Investors] is not responsible for shareholder record keeping, nor does it specifically seek new investors to keep utility financing costs reasonable.”13 The Department maintained that this association’s impact on legislation and regulatory policy likely benefits shareholder interests, not ratepayer interests.

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9 Ex. GP-23, at 2–3 (Jacobson Rebuttal).
10 Id.
11 Id. at 3.
12 Department brief, at 4 (quoting Ex. GP-21, at 3 (Jacobson Direct)).
13 Department brief, at 6.
3. OAG

OAG recommended that Great Plains should not recover dues paid to MN Utility Investors or Edison Electric. Like the Department, OAG argued that MN Utility Investors advances the interests of utility investors, not ratepayers. OAG stated, “the only impact [MN Utility Investors] has on utility customers is higher prices, which come by way of increased rate-case expense requests as they have here.” OAG argued that Edison Electric is an organization that represents electric utilities, and the Company had only offered vague statements about how its participation in Edison Electric’s Solid Waste Group relates to the provision of natural gas service.

OAG argued that Great Plains bears the burden of proving that the expenses it seeks to recover are reasonable and necessary for the provision of natural gas service, and it had failed to meet its burden for both the MN Utility Investors dues and Edison Electric dues. OAG asserted that to the extent there was any doubt as to the reasonableness of these organizational dues, that doubt should be resolved in favor of the ratepayer.

C. ALJ Recommendation

The ALJ agreed with the Department and OAG that Great Plains should not recover the cost of dues paid to MN Utility Investors or Edison Electric. In reviewing the activities of both organizations, the ALJ concluded that these expenses did not benefit ratepayers nor did they reasonably relate to the provision of natural gas service.

Regarding MN Utility Investors, the ALJ concluded, “[a] review of [MN Utility Investors] activities, purpose, and mission establishes that the organization is primarily focused on advancing the interests of utility shareholders in the regulatory policy-making and law-making process. As a result, it does not provide benefits to ratepayers and, thus, should not be included in the calculation of the revenue requirement.”

Regarding Edison Electric, the ALJ found that the Company “provides no evidence of how the [Solid Waste Group] is utilized by [Great Plains] for its natural gas operations,” and concluded that the Company’s ratepayers “should not be responsible for the cost of dues for an organization primarily focused on representing the interests of electric companies.”

The ALJ ultimately found that Great Plains “has failed to show that it is reasonable for ratepayers to pay for the dues” of MN Utility Investors and Edison Electric. The ALJ thus recommended that the Commission exclude the cost of dues paid to Edison Electric and MN Utility Investors, totaling $11,964, from the calculation of the Company’s revenue requirement.

14 OAG brief, at 8.
15 ALJ’s Report, Findings ¶ 95.
16 Id., ¶¶ 96–97.
17 Id., ¶ 98.
D. Commission Action

The Commission agrees with the ALJ that Great Plains has not shown that membership dues for MN Utility Investors or Edison Electric are a reasonable expense that should be included in the Company’s revenue requirement. Great Plains has not submitted sufficient evidence that membership in these organizations is reasonably related to providing safe and reliable natural gas service or that the memberships benefit ratepayers. Absent this evidence, ratepayers should not be responsible for these expenses.

Great Plains argues that it should recover the dues paid to MN Utility Investors because this association’s involvement in legislation and regulatory policy directly and indirectly impacts utilities and their customers. However, the fact that an organization may influence policy that impacts utilities and ratepayers does not necessarily mean that ratepayers should pay for the utility’s membership in that organization. The evidence offered by Great Plains shows that MN Utility Investors’ activities focus on empowering shareholders in the legislative and regulatory processes to advance policies that benefit shareholders, not ratepayers. Great Plains has also not demonstrated that dues paid to MN Utility Investors qualify as a recoverable investor relations expense. The Commission concludes that MN Utility Investors dues are not a reasonable utility expense that should be included in the Company’s revenue requirement.

Great Plains also argues that dues paid to Edison Electric should be included in its revenue requirement because Edison Electric’s Solid Waste Group “is responsible for addressing solid and hazardous waste issues on behalf of the utility industry and is utilized by Great Plains in a number of ways specifically for its natural gas operations.” However, the Company’s statement that membership in this group is utilized for natural gas operations is not sufficient evidence to meet its burden to prove that this is a reasonable utility expense. Great Plains needed to provide more detail and specificity about how its participation in the Solid Waste Group is related to its natural gas operations in order to justify why ratepayers should cover this cost.

For the foregoing reasons, the Commission will disallow $11,964 of the Company’s revenue requirement for dues paid to MN Utility Investors and Edison Electric.

VI. Incentive Compensation

A. Introduction

Great Plains proposed a test-year employee incentive compensation expense of $261,892, which reflects a 9.5% incentive compensation rate. The Company calculated the 9.5% rate by dividing the total compensation payout, based on a 100% target level per job classification for each employee, capped at 15% of salary, by the total salary of all job classifications eligible for incentive compensation.

The Department and Great Plains disagreed on whether the Company should be required to file an annual report for the purpose of tracking any unpaid incentive compensation amounts and returning those amounts to ratepayers.

18 Ex. GP-23, at 3 (Jacobson Rebuttal).
B. Positions of the Parties

1. The Department

The Department did not dispute the amount of Great Plains’s incentive compensation request but clarified that its support for the proposal was contingent upon requiring the Company to file an annual report that tracks incentive compensation payments and to refund unpaid amounts to ratepayers.

The Department stated that the Commission has long required other utilities to annually refund amounts not paid under incentive compensation plans. Requiring such refunds, the Department maintained, is reasonable considering that the Company ultimately decides whether to make payments under the plan. To require ratepayers to pay compensation costs that the Company decides not to award would conversely be unjust. To illustrate this point, the Department noted that in 2015, Great Plains did not pay incentive compensation to its employees. The Department stated that in such circumstances, it is reasonable to require the Company to refund the unpaid amounts collected from ratepayers.

For these reasons, the Department recommended approving the Company’s incentive compensation recovery request, with the condition that Great Plains be required to annually track its compensation payments and make refunds of amounts not paid under the plan.

2. Great Plains

Great Plains recommended that the Commission allow recovery of incentive compensation costs without requiring annual reporting and refunds. Great Plains stated that the Department’s recommendation would place the Company in a disadvantageous financial position by potentially requiring a refund of some revenues without consideration of, for example, compensation amounts paid in subsequent years that may offset any unpaid amounts from an earlier year. The Company recommended rejecting this type of single-issue ratemaking.

C. The Recommendation of the Administrative Law Judge

The ALJ found the Company’s incentive compensation costs to be reasonable and recommended that the Commission authorize the recovery of $261,892. But the ALJ also recommended that the Commission require the Company to file annual reports and make refunds of unpaid amounts, consistent with the Department’s recommendation to do so. The ALJ found that Great Plains’s decision not to pay incentive compensation to its employees in 2015 underscores the reasonableness of such an approach.

D. Commission Action

The Commission concurs with the ALJ and the Department that it is reasonable to allow recovery of $261,892 in incentive compensation costs, while also requiring annual reporting that tracks the Company’s compensation payments and requires the return of unpaid compensation funds to ratepayers.

Great Plains argued that annual reporting leading to ratepayer refunds is a form of single-issue ratemaking, which contravenes long-standing ratemaking principles. But the reasonableness of
recovering incentive compensation through rates is contingent on the incentives advancing ratepayer interests. If the incentives are not paid, it is reasonable to infer that the desired ratepayer advantages were not achieved. Granting the cost-recovery request as proposed would authorize the Company to retain unpaid incentive compensation to the detriment of ratepayers—in this case, there is no corresponding ratepayer benefit justifying such an outcome.

On the other hand, disallowing the recovery of any incentive compensation costs could unreasonably limit the Company’s efforts to reduce its overall employee compensation costs, or disincentivize the use of compensation as a tool to improve performance consistent with ratepayer interests. To blunt the disadvantage of either total disallowance or total allowance, the Commission will instead require an annual filing to examine compensation amounts paid to employees under the plan and require that any unpaid amounts be returned to ratepayers. This approach reasonably balances the interests of shareholders and ratepayers.

Specifically, the Commission will require Great Plains to determine the amount of actual incentive compensation paid that is recoverable from ratepayers by applying the 15-percent cap to each employee’s salary. The annual incentive compensation report must include the following:

- A description of the incentive compensation plan;
- The accounting of amounts of unpaid incentive compensation built into rates to be returned to ratepayers;
- An evaluation of the incentive plan’s success in meeting its stated goals, including the payout ratio;
- A proposal for refund if applicable; and
- Identification of each performance indicator and its associated scorecard information, such as the measure, the goal for various attainment levels (threshold, target, maximum), its funding weight and the actual result achieved; and a report of the overall plan payout percentage attained relative to the target goal of 100%.

VII. Rate Case Expense

A. Introduction

Great Plains requested recovery of $592,555 in estimated rate case expenses. These expenses were for six categories of costs, including:

- Rate of return consulting fees;
- Outside legal fees;
- Company staff hearing expenses;
- Montana–Dakota staff public input meeting expense;
- State agency fees; and
- Administrative costs (Federal Express and miscellaneous).

Great Plains proposed a four-year amortization period over which to collect the expenses.
The Department and Great Plains disagreed on whether the Company should be required to track and apply any over-recovery of costs as a credit to the Company’s revenue requirement in its next rate case.

B. Positions of the Parties

1. The Department

The Department did not challenge the reasonableness of the Company’s estimated rate case expenses or its proposal to amortize the costs over four years. But the Department recommended that the Commission require the Company to track its costs and apply any over-recovery as a credit to the revenue requirement in the Company’s next general rate case.

The Department maintained that it would be unreasonable to allow the Company to simply retain revenues for rate case costs not, in fact, incurred. The Department noted that the Commission required the Company, in its last general rate case, to credit any excess amount of rate case expenses collected to its revenue requirement in its next general rate case.

2. Great Plains

Great Plains opposed the Department’s recommendation to track its rate case expenses and credit any over-recovery of costs in its next general rate case. The Company asserted that this approach would also result in single-issue ratemaking, echoing its assertions made in opposing refunds for unpaid incentive compensation. The Company stated that requiring the Company to credit any amount of rate case expense recovered but not incurred does not take into consideration other costs that may offset those revenues.

C. The Recommendation of the Administrative Law Judge

The ALJ rejected the Company’s argument and instead recommended that the Commission require the Company to both track and calculate the final rate case expenses and credit any over-recovery to its proposed revenue requirement in its next general rate case, finding that this is the most reasonable approach.

D. Commission Action

The Commission concurs with the ALJ that it is reasonable to require the Company to track any over-recovery of rate case expenses and credit that amount to the revenue requirement in its next general rate case.

The Commission is not persuaded that ratepayers are served or adequately protected by allowing the Company to retain amounts collected specifically for rate case expenses that the Company does not ultimately incur. The alternative, which would be to deny recovery of the requested costs, is also unreasonable. For these reasons, the Commission will allow the Company to recover its estimated costs using a four-year amortization period, while also requiring that the Company credit any excess amounts to its revenue requirement in its next general 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 a 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 determined for each component during the ratemaking process.

In this case, the only contested cost-of-capital issue is the cost of equity.19

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

VIII. Capital Structure

Great Plains is a division of Montana-Dakota Utilities, Co., and Montana-Dakota Utilities, Co. is a subsidiary of MDU Resources Group, Inc. (MDU), a diversified natural resource company.20 The Company therefore has no capital structure of its own and must be assigned one for ratemaking purposes.

The Company proposed that it be assigned a capital structure based on the capital structures of the companies in its comparable-utility proxy group. The Department analyzed the Company’s proposal using its own proxy group, and concluded that the differences were not significant and that the Company’s proposed capital structure was reasonable. The proposed capital structure is:

<table>
<thead>
<tr>
<th>Capital Structure</th>
<th>Percentage</th>
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<tbody>
<tr>
<td>Long-Term Debt</td>
<td>45.132%</td>
</tr>
<tr>
<td>Short-Term Debt</td>
<td>4.053%</td>
</tr>
<tr>
<td>Common Equity</td>
<td>50.815%</td>
</tr>
</tbody>
</table>

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

IX. Cost of Long- and Short-Term Debt

The Company proposed a cost of long-term debt of 4.712%, and a cost of short-term debt of 3.693%. 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.

The ALJ agreed that the proposed cost of long- and short-term debt, and the resulting weighted cost of debt, were reasonable and recommended that the Commission approve them.

19 The OAG did not take a position on capital structure or the cost of Great Plains’s debt in this case.

The Commission concurs, and adopts a cost of long-term debt of 4.712%, and a cost of short-term debt of 3.693%.

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.21

One of the critical components of that fair and reasonable return upon investment is the return on common equity, which—together with debt—finances 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.

The analysis would normally begin by examining the price of the utility’s stock, but Great Plains is a division of a subsidiary of MDU Resources Group, Inc. 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.

B. The Analytical Tools

Great Plains and the Department conducted cost-of-equity studies, with analyses based on comparison groups of utilities they considered similar enough to Great Plains to serve as proxies in determining the Company’s cost of equity. Both used the Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance.

The Company and the Department further analyzed the appropriate cost-of-equity using a Capital Asset Pricing Model (CAPM) analysis. And the Company also conducted analyses using Bond Yield Plus Risk Premium and Expected Earnings models.

The DCF model uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is sufficient to induce investment. The model is derived from a formula used by investors to assess the attractiveness of investment opportunities using three inputs—dividends, stock prices, and growth rates. DCF modeling can be performed using constant, “two-growth,”22 and multistage dividend-growth assumptions.

21 Minn. Stat. § 216B.16, subd. 6 (emphasis added).

22 A two-growth model assumes that dividends grow at one rate for a short time, and then grow at a second, sustainable rate in perpetuity.
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 risk premium determined by subtracting the 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 Bond Yield Plus Risk Premium Model determines the cost of equity by adding to the risk-free rate a premium reflecting the greater returns required by equity holders. The Commission has historically relied on the Bond Yield Plus method less heavily, as the model is backward-looking and more prone to volatile and unreliable outcomes.

According to the Company, an Expected Earnings analysis calculates the earnings that an investor expects to receive on the book value of a stock, using proxy companies to provide a range of the expected returns on a group of risk-comparable companies. The Company argued that the range can help determine the opportunity cost of investing in the Company, and therefore inform decisions about reasonable rates of return on equity.

C. The Positions of the Parties

1. The Company

The Company proposed a return on equity of 10.2%, based on constant growth and two-growth DCF models of an eight-utility proxy group, along with CAPM, Bond Yield Plus Risk Premium, and Expected Earnings analyses.

The Company’s chosen proxy group started with companies classified by Value Line as “natural gas distribution utilities,” and then screened out companies based on seven screening criteria. In the Company’s final analyses, the proxy group comprised: Atmos Energy Corporation; Northwest Natural Gas Company; ONE Gas, Inc.; Spire, Inc.; Southwest Gas Corporation; New Jersey Resources Corporation; NiSource, Inc.; and South Jersey Industries, Inc.

The Company also advocated for factoring in and adjusting for business risks, economic factors and other factors specific to the Company, including company size and customer concentration, and recent-average approved Returns on Equity (ROEs) in other rate-setting proceedings. According to the Company, these factors distinguish Great Plains and justify an ROE higher than the Department recommended, and relatively higher than the proxy group would otherwise indicate.

Finally, the Company further argued that its ROE should be adjusted upward by 10 basis points to account for flotation costs.23

23 Flotation costs are sometimes added to the cost of equity to reflect the fact that companies do not receive the full price of the stock they issue—the amount they receive is less than the initial offering price of the stock due to legal and issuance fees incurred out-of-pocket, and underwriting fees withheld from sale proceeds paid to the company. Flotation costs to adjust for these fees are sometimes added to the cost of equity to credit the company with the full amount of the issuance.
2. The Department

The Department recommended a return on equity of 8.82%, based on constant growth and two-growth DCF models of an five-utility proxy group. The Department performed a CAPM analysis to perform a check on the reasonableness of the DCF model results.

The Department’s proxy group comprised five of the eight companies in the Company’s proxy group: Atmos Energy Corporation; Northwest Natural Gas Company; ONE Gas, Inc.; Spire, Inc.; and Southwest Gas Corporation.

The Department reasoned that three companies included in the Company’s proxy group—New Jersey Resources Corporation; NiSource, Inc.; and South Jersey Industries, Inc.—should each be excluded from the proxy group as not contributing reliable proxy information. The Department screened South Jersey and NiSource out of the proxy group because they did not meet a threshold of earning 60% of their revenue through natural gas distribution, reasoning that a 60% threshold was a reasonable standard for whether a company was comparable to Great Plains. And the Department excluded New Jersey Resources Corporation for uncertain creditworthiness.

The Department agreed with the Company that a flotation cost adjustment to an ROE based on DCF analysis would be reasonable, but disputed that the Company’s proposed 10-basis-point adjustment was justified by the record. The Department argued that the Company’s proposed adjustment did not account for equity issuances that do not incur the costs that the flotation adjustment was intended to address. The Department supported a five-basis-point flotation cost adjustment.

D. The Recommendation of the Administrative Law Judge

The ALJ determined that, while the Department’s DCF analysis was reliable, it was not the sole measure of a reasonable return for the Company. The ALJ concluded that the Department’s DCF analysis needed to be viewed in light of (1) the Department’s CAPM analysis results, (2) risks particular to Great Plains that are not sufficiently accounted for by the proxy group method of analysis, and (3) the competitive market for equity investment.24 The ALJ agreed with the Department’s proxy group selection, concluding that the Department appropriately excluded South Jersey, NiSource, and New Jersey Resources Corporation from the proxy group.

Finally, the ALJ agreed with the Department that the Company had not established that a 10-basis-point flotation adjustment was sufficiently justified by the record. The ALJ reasoned that at least some of the Company’s equity issuance used methods that did not incur the costs that a flotation adjustment was intended to address, and found reasonable the Department’s proposal to allow adjustment for half of the Company’s proposed flotation costs.

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24 ALJ’s Report, Findings ¶ 280.
The ALJ recommended that the Commission set the ROE at 9.67%, derived from the mean-high ROE established by the Department’s DCF analysis, and that the ROE should include a five-basis point flotation adjustment.

E. Commission Action

Setting the cost of equity is a fact-intensive and record-specific judgment. The Commission must ultimately establish a reasonable rate of return that is supported by the evidence in the record considered in its entirety. The diversity of analytical methods in the record in this case do not lead to wildly disparate conclusions or recommendations. The Commission believes that the record evidence in this case, including the broad diversity of modeling and expert testimony, establishes a range of reasonable costs of equity, within which the Commission must identify one value.

The record does not formulaically dictate a particular ROE to be approved. Instead, the record presents a range of reasonable returns on equity that the Commission has carefully evaluated based on the analyses and arguments in the record. As such, the Commission will set the Company’s authorized ROE in light of the record as a whole.

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 Commission agrees with the ALJ that the DCF model provides the best basis in this record for determining return on equity. 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.

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.

The CAPM and Risk Premium methods, on the other hand, require expert judgment at nearly every turn—determining the term of the risk-free, interest-bearing investment used as a benchmark, determining the time frame for calculating growth rates, determining the beta that represents market volatility, determining the historical periods over which to measure returns. Almost none of these inputs are simple matters of fact and public record.

The Commission also agrees with the ALJ’s decision to give little weight to the Company’s Expected Earnings model, as it is an accounting-based—rather than a market-based—approach.

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25 Id., ¶ 284.
26 Id., ¶ 295.
The Commission has considered and weighed the relevant factors, which include, but are not limited to the relative objectivity, transparency, reliability, rigor, and timeliness of the analytical models in the record, and their inputs; the composition and representative nature of the proxy groups proposed in each analysis; the ROEs that the parties recommended based on their modeling results; and the Company’s approved capital structure and costs of obtaining equity investment.

Most importantly, the approved ROE must adequately assure a fair and reasonable return in light of the Company’s risk profile and costs of obtaining equity investment. In light of the relevant factors, the Commission will approve a cost of equity of 9.53%, which includes a five-basis-point adjustment for flotation costs.

The Commission finds a 9.53% ROE to be reasonable and appropriate based on the two-growth DCF modeling done by the parties. In particular, it is supported by using the Department’s analytical model, but after the model is (1) adjusted to include South Jersey and NiSource in the proxy group and (2) using the most recent available record information about the proxy group companies, which is contained in the Department’s surrebuttal testimony of March 3, 2020.28

Upon review of the record information about the proxy companies, the Commission has determined that the Department excluded South Jersey and NiSource as a result of one-time financial events that affected their ability to meet the 60% screen. The Commission concludes that, but for those one-time events, the companies would be appropriate members of the proxy group. Accordingly, the Commission believes that a reasonable DCF analysis on these facts should reflect the inclusion of South Jersey and NiSource in the proxy group. With the inclusion of these companies in the proxy group, the Commission considers the proxy group to be appropriately representative of the risks and costs of Great Plains, and no further risk-factor adjustment is warranted.

The resulting mean two-growth DCF analysis result supports a 9.48% cost of equity, which the Commission will adjust by five basis points for flotation costs.

Accordingly, the Commission finds, based on its experience, technical competence, and specialized knowledge in the evaluation of the evidence in the hearing record, that an ROE of 9.53% is sufficient to establish just and reasonable rates, while adequately assuring a fair and reasonable return in light of the Company’s unique risk profile, capital structure, and costs of obtaining equity investment.

XI. 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 as follows:

<table>
<thead>
<tr>
<th>Component</th>
<th>Ratio</th>
<th>Cost</th>
<th>Weighted Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long-Term Debt</td>
<td>45.132%</td>
<td>4.712%</td>
<td>2.126%</td>
</tr>
<tr>
<td>Short-Term Debt</td>
<td>4.053%</td>
<td>3.693%</td>
<td>0.150%</td>
</tr>
<tr>
<td>Common Equity</td>
<td>50.815%</td>
<td>9.53%</td>
<td>4.843%</td>
</tr>
<tr>
<td>Total</td>
<td>100.000%</td>
<td></td>
<td>7.119%</td>
</tr>
</tbody>
</table>

28 The accuracy of these figures was confirmed by the Company at the Commission’s August 6 meeting.
SALES FORECAST

XII. Sales Forecast

A. Introduction

As part of its rate case, Great Plains included a sales forecast. The forecast calculates the projected sales to each customer class during the test year (measured in dekatherms or Dk), based on projected numbers of customers and billing units for each class. (Billing units refers to the average number of customers throughout the year. Because customers such as grain dryers stop taking service for part of the year, the number of customers exceeds the number of billing units.)

Parties analyze a utility’s sales forecasts because the amount of a utility’s sales will influence the utility’s operating costs as well as its revenues. In designing rates, sales volumes are used to allocate costs in the CCOSS; when establishing final rates, the sales volumes are used to determine the overall revenue requirements, as well as the individual tariff rates.29

In the Company’s last rate case, the Commission directed Great Plains to provide the following sales-forecast-related information in future rate filings, to the extent practicable, or explain why the information is not available:

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

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

iii. raw sales, customer count, billing system, and weather data that is as up to date as possible and that goes back at least 20 years;

iv. hourly historical weather (temperature) data, rather than (or in addition to) daily historical data;

v. if, in the future, [the Company] updates, modifies, or changes its billing system, a bridging schedule that fully links together the old and new billing systems and validates that there is no difference between the two billing systems;

29 Ex. DER-2 at 2 (Shah Direct).
vi. any, and all, data used for its sales forecast 30 days in advance of its next general rate case; and,

vii. detailed information sufficient to allow for replication of any and all Company derived forecast variables.  

B. Positions of the Parties

Great Plains claimed to have fulfilled these forecasting requirements in this docket, and argued that the data supported its sales forecast for the 2020 test year. Great Plains also affirmed its willingness to fulfill these requirements in future rate proceedings. That said, the Company acknowledges that it provided only 15 years of billing data for residential customers and 11 years of billing data for firm general service customers, rather than the 20 years of data contemplated by item (c). Great Plains explained that it had changed its customer rate classifications in 2004 and 2007, and argued that it would be inappropriate to combine sales data using the earlier definitions and the later definitions.

The Department ultimately concurred that Great Plains had fulfilled the forecasting requirements in the current rate case: While the Company failed to provide the 20 years of data, it provided an explanation for its failure to do so. Moreover, the Department found the Company’s sales forecasts to be reasonable. Prospectively, however, the Department recommended that the Commission order Great Plains to retain customer data even if the Company changes its customer classifications.

C. The Recommendation of the Administrative Law Judge

The ALJ concurred with the Department’s arguments and recommendations, finding as follows:

324. Because of the lack of data available before 2004 and between 2004 and 2007, the [Department] also recommends that the Commission require [Great Plains] to retain customer data such that, in the event the Company proposes different rate structures in the future, past data would remain available to compare the different rate structures in subsequent rate cases….

325. Based upon the review of the [Department], the Administrative Law Judge recommends that the [the Company]’s sales forecast for test year 2020 be accepted as reasonable. The [ALJ] further recommends that the Commission adopt the [Department]’s recommendations regarding the retention of data and the continuation of the compliance requirements set forth in [the prior rate case order].

30 In the Matter of the Petition by Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota, Docket No. G-008/GR-15-879, Findings of Fact, Conclusions, and Order (2016 Order), at 51-52, Ordering Para. 16 (September 6, 2016).

31 ALJ’s Report, Findings ¶¶ 324–325.
D. Commission Action

Having reviewed the record, the Commission finds that the data in the record is sufficient to establish the reasonableness of the Company’s sales forecast for test year 2020. Accordingly, the Commission concurs with the parties and the ALJ that no additional forecasting data is required, and will accept the forecasts as reasonable.\(^2\)

The Commission also finds that the forecasting requirements have demonstrated their utility, and will therefore direct Great Plains to continue abiding by those requirements in future rate proceedings.

Finally, the Commission will clarify that Great Plains must retain customer data even if the Company changes its customer classifications. While the ALJ emphasized the need to retain this data to facilitate comparisons between different rate structures in subsequent rate cases, the Commission has a somewhat different objective. The Company is free to argue that some customer data is no longer relevant or reliable, but that claim should not preclude other parties from having the opportunity to analyze the data and draw their own conclusions. Therefore the Commission will adopt the ALJ’s Report, Finding 324, modified as follows:

Because of the lack of data available before 2004 and between 2004 and 2007, the [Department] also recommends that the Commission require [Great Plains] to retain customer data such that, in the event the Company proposes different rate structures in the future, past data would remain available to compare the different rate structures in subsequent rate cases. That is, going-forward, just because the Company decides to change the rate structure does not mean the customer’s historical consumption data has changed or becomes unusable. [Great Plains] agrees to this recommendation.

CLASS COST OF SERVICE STUDY ISSUES

XIII. Class Cost of Service Study

A. Background

As required by rule, the Company’s rate-case filing included a class cost of service study (CCOSS).\(^3\) The purpose of a class cost of service study is to determine, as accurately as possible, the costs of serving each class of customer. While these costs cannot be determined with

\(^2\) To rectify a typographical error in the ALJ’s Report, Finding 305, the Commission will adopt the finding modified to say that for 2020, Great Plains projected having a total 22,029.40 billing units and 22,038 customers, selling a total 3,813,170 Dk, and transporting an additional 4,675,000 Dk. See Ex. GP 18, MTS-1 at 1-2 (Shoemake Direct), and Summary of Billing Units and Customers; Ex. DER-2 at 4 (Shah Direct).

\(^3\) Minn. R. 7825.4300 C.
precision, a CCOSS that generates clear results based on clear assumptions can help the Commission understand the costs that a utility incurs in serving each customer class.

For purposes of its CCOSS, Great Plains divided its customers into six classes: Residential (Firm) Service, General Firm Service, Interruptible Grain Drying Service, Small Interruptible Gas Transportation Service, Large Interruptible Gas Sales Service, and LargeInterruptible Gas Transportation Service. In establishing these classes, the Company distinguished between firm and interruptible service, and between sales and transportation service.

When a customer subscribes for firm service, the utility agrees not to curtail or interrupt that service except in an emergency. Customers subscribing for interruptible service, on the other hand, agree that the utility may curtail or interrupt their service as specified in tariffs—typically during extremely cold weather when the demand for gas is at its peak. Because it costs more to provide firm service than interruptible service, utilities charge more for firm service.

When a customer subscribes for sales service, a gas utility must purchase a supply of natural gas, arrange for it to be transported via an interstate pipeline to the utility’s distribution plant, and then deliver the gas via its distribution plant to the customer. In contrast, a customer that subscribes for transportation service bears the responsibility for procuring its own supply of gas (typically though the services of an unregulated gas supplier), and the utility then delivers the gas from the pipeline to the customer.

B. Introduction

A utility typically conducts a CCOSS in three steps. First, the utility “functionalizes” costs by dividing them according to the purpose for which they were incurred. Second, the utility classifies the costs into three basic categories. Third, the utility allocates costs to the various customer classes.

The utility typically functionalizes costs according to FERC’s Uniform System of Accounts. Typical functions include production (costs associated with producing, purchasing, or manufacturing gas); storage (costs associated with storing gas); transportation (costs incurred in transporting gas from interstate pipelines to the distribution system); distribution (costs incurred to deliver the gas to the customers, such as gas distribution mains and meters); and general and administrative costs.

For each function, the utility then classifies the costs as being driven by the number of customers (customer costs), by the total energy consumed (energy costs), or by the maximum amount of energy that the class requires at any given moment, or during the time of peak demand on the system (demand or capacity costs). Where a functionalized cost cannot be classified as related to the number of customers, amount of energy, or amount of demand, a utility can create a formula based on a composite of these classifications.

There are various methods for making these classifications—and the primary difference often focuses on how to divide the cost of distribution plant between customer costs and demand costs. For example, the Minimum System method calculates the customer share of this cost as the cost of a hypothetical distribution plant built with minimum-sized pipes. Any distribution costs that exceeds this amount would reflect the need to provide customers with more than the
minimum amount of gas—that is, it would reflect the demand for gas—and should therefore be classified as demand costs. To use this method, however, a utility must be able to determine its cost per foot to buy and install its minimum-sized distribution pipe.

C. Positions of the Parties

In accordance with Commission order,\textsuperscript{34} Great Plains filed multiple CCOSSs, including studies based on the Minimum System method.

The Department raised various concerns regarding the Company’s CCOSSs. In particular, the Department recommended that Great Plains revise the way that it classifies and allocates a variety of functionalized costs as follows:

- Land and Land Rights (FERC Account No. 374)—classify and allocate on the same basis as Distribution Plant.
- Structures and Improvements (FERC Account No. 375)—classify and allocate on the same basis as Distribution Plant.
- Maintenance of Structures and Improvements (FERC Account No. 886)—classify and allocate on the same basis as Distribution Plant.
- Other Equipment (FERC Account No. 387)—classify and allocate on the same basis as Distribution Plant.
- Maintenance of Services (FERC Account No. 892)—allocate on the same basis as Services (FERC Account No. 380).

In addition, the Department recommended that Great Plains allocate the costs of certain equipment solely to the specific customer classes that benefit from them. Specifically, the Department recommended reallocating the following:

- The cost of special and expensive installations of measuring and regulating station equipment located on the distribution system, and recorded to Industrial Measuring and Regulating Station Equipment (FERC Account No. 385) and Maintenance of Measuring and Regulating Station Equipment-Industrial (FERC Account No. 890).
- The cost of large measuring and regulating stations located on local distribution systems, and recorded to Measuring and Regulating Station Expenses-Industrial (FERC Account No. 876).

Finally, the Department argued that the Company’s use of the Minimum Size method was undermined by the lack of adequate data. For more than 70 percent of its distribution lines (by length), Great Plains had combined the cost of the small pipes with the costs of the larger pipes,

\textsuperscript{34} 2016 Order, at 34.
thereby impeding efforts to calculate the cost per foot of buying and installing the minimum-sized pipes.

Given these shortcomings, the Department could not recommend that the Commission rely on any of the Company’s CCOSSs for purposes of setting rates in the current case. Instead, the Department recommended that Great Plains fix the various problems it had identified when the Company files its next rate case.

Without conceding every objection raised by the Department, Great Plains ultimately agreed that the Department’s recommendations provided an appropriate way to proceed.

D. The Recommendation of the Administrative Law Judge

The ALJ accepted the recommendations of the parties, as follows:

354. [T]he Administrative Law Judge recommends that the Commission not approve the CCOSSs that [Great Plains] presented in this case.

355. In addition, the Commission should require the Company, in its next rate case, to reclassify and/or reallocate the following eight FERC accounts, as recommended by the [Department]: 374, 375, 886, 387, 385, 890, 876, and 892.

356. Finally, the Commission should perform an improved minimum-size CCOSS using per-foot replacement costs for each type and size of installed distribution pipes, and file such a study in the next general rate case, as recommended by the [Department].

Great Plains and the Department each recommended that the Commission adopt these findings, but with modifications to Finding 356. The Company recommended finding that “the Commission should require the Company to perform an improved minimum-size CCOSS….” And the Department recommended “an improved minimum-size CCOSS using reliable and supported per-foot replacement costs….”

E. Commission Action

The Commission has long relied on utilities and other parties to develop CCOSSs that might inform ratemaking decisions. The Commission regrets that the Company’s efforts have not resulted in a reliable study, but appreciates the efforts of the Company and the Department in rigorously analyzing the matter to help the Commission avoid giving unwarranted reliance to flawed studies.


36 The Department also recommended correcting a typographical error in Finding 350, replacing a reference to a “medium-size CCOSS” with “minimum-size CCOSS.”
Having reviewed the record and the agreement among the parties, the Commission will adopt the ALJ’s recommendations as modified by the parties. The guidance provided by the Department will help ensure improved CCOSSs in the future.

RATE DESIGN ISSUES

XIV. Customer Service Charges

A. Introduction

While revenue apportionment focuses on how revenue responsibility should be apportioned among customer classes, setting the customer service charge addresses how revenues are collected within each customer class. The monthly customer service charge is a fixed monthly charge assessed without regard to usage levels. It provides a method of more closely matching the causes and recovery of fixed customer-related costs such as the cost of meters, service lines, meter reading, and billing.

Great Plains’ current monthly customer service charges are $7.50 for residential customers, $23.00 for small firm customers, $28.50 for large firm customers, $145.00 for small interruptible sales customers, $200.00 for small interruptible transport customers, $230.00 for large interruptible sales customers, and $260.00 for large interruptible transport customers. The average customer-related cost, according to the Company’s CCOSS, is $24.39 per month for a residential customer.

B. Positions of the Parties

1. The Company

Great Plains proposed to increase monthly customer service charges to $9.00 for residential customers, $27.50 for small firm customers, $35.00 for large firm customers, $150.00 for small interruptible sales customers, $250.00 for small interruptible transport customers, $500.00 for large interruptible sales customers, and $560.00 for large interruptible transport customers.

Great Plains also proposed establishing a monthly customer service charge of $450.00 for the newly introduced interruptible grain drying class. Customers who will be part of the interruptible grain drying class are currently part of either the small interruptible sales class or the large interruptible sales class.

Great Plains argued that the proposed increases would better align the customer service charge with the cost of serving each customer class. The Company stated that it is appropriate to attempt to collect fixed costs through the fixed customer service charge whenever possible. Additionally, the Company argued that the proposed increases would reduce intra-class subsidies while mitigating rate increases to the residential customer class. Finally, Great Plains argued that the proposed increases would not significantly affect energy conservation behavior, noting that the customer service charge is a relatively small part of a customer’s overall bill.
2. The OAG

The OAG opposed customer service charge increases generally, and especially the proposed increases to the residential and small firm customer classes. First, the OAG argued that the proposed increases would discourage energy conservation, contrary to statutory directives to encourage conservation. The OAG stated that increasing fixed customer service charges relative to volumetric charges reduces customers’ incentive to conserve energy because it weakens the link between consumption and cost.

Additionally, the OAG argued that the proposed increases would disproportionally impact low-usage customers, because the customer service charge would be a higher percentage of their overall bill.

3. The Department

The Department supported most of Great Plains’s proposed customer service charge increases, although the Department recommended smaller increases for the interruptible grain drying and large interruptible classes to better align with the CCOSS. Ultimately, Great Plains and the Department agreed that the customer service charge should be set at $400.00 for the interruptible grain drying and large interruptible transport classes, and $355.00 for the large interruptible sales class.

Overall, the Department agreed with the Company that the increases would reduce intra-class subsidies by moving the majority of the rate classes closer to the costs identified in the CCOSS. The Department explained that when a customer service charge does not recover the full customer-related cost for a particular class, a higher proportion of the class’s revenue responsibility is recovered through the volumetric charge—shifting more of the recovery to high-usage customers.

Furthermore, the Department agreed with the Company that the proposed customer service charge increases were not large enough to impact customers’ energy consumption patterns, particularly since natural gas usage is relatively inelastic.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission approve Great Plains’s proposal to increase the customer service charges for the residential, small firm, large firm, small interruptible sales, and small interruptible transport classes, and approve the Department and Company’s agreement for the large interruptible and interruptible grain drying classes.

D. Commission Action

Having reviewed the record, including the oral and written arguments of all parties and members of the public, the Commission finds that it cannot adopt the recommendation of the Administrative Law Judge with respect to the increases in the Company’s customer service charges. Increasing the fixed charge reduces the conservation incentive inherent in a rate that is

37 See Minn. Stat. § 216B.03.
split between a fixed and a volumetric charge. The Company is significantly underperforming its conservation goals. The Commission is disinclined to adopt the proposed fixed charge increases in this case, as it would likely make the Company’s conservation goals that much harder to meet.\textsuperscript{38} For this reason, the Commission will direct the Company to maintain its customer service charges at the current levels for existing customer classes.

With respect to the newly proposed interruptible grain drying class, the Commission will set the customer service charge at $230.00. This is the current customer service charge for the large interruptible sales class, which is one of the two classes contributing to the interruptible grain drying class. This customer service charge appropriately aligns the interruptible grain drying class with the existing customer classes.

XV. Bill Calculation

A. Introduction

Currently, Great Plains’s customer service charge is billed to each customer as a fixed monthly charge, regardless of the number of days in the month. Great Plains proposed to instead bill the customer service charge as a daily amount for residential, small firm, and large firm customers. Great Plains calculated the daily customer service charge by multiplying the proposed monthly customer service charge by 12 and dividing the total by 365 to obtain a daily rate.

B. Positions of the Parties

1. The Company

Great Plains argued that using a daily rate for the customer service charge would better align with how customers are actually billed. Great Plains explained that, because of weekends and holidays, the number of days in a bill cycle varies slightly from month to month. The Company argued that it is easy for customers to see the period covered by each bill, and applying a daily customer service charge would help clarify that some months reflect 29 days of consumption while others reflect 30 days of consumption, allowing customers to precisely calculate their bill for an upcoming month.

Additionally, the Company stated that implementing a daily customer service charge would clarify the prorated amount to be charged when customers start or stop service in the middle of a billing cycle.

2. The Department

The Department opposed Great Plains’s proposal and argued that it would increase the complexity of customer bills with no clear benefit. The Department stated that any monthly variation in customers’ bills would be extremely small, and a simple monthly charge is easier for customers to understand.

\textsuperscript{38} While natural gas consumption is relatively inelastic, it is not completely inelastic.
C. **The Recommendation of the Administrative Law Judge**

The Administrative Law Judge recommended that the Commission reject Great Plains’s bill calculation proposal for the reasons outlined by the Department.

D. **Commission Action**

The Commission concurs with the Administrative Law Judge and the Department that Great Plains’s proposal to implement a daily customer service charge is unnecessarily complex. As a general principle of rate design, rates should be understandable and easy to administer. Great Plains’s proposal would increase the complexity of customers’ bills without any significant benefit, since the month-to-month variation would be very small. For this reason, the Commission will reject Great Plains’s proposal.
# FINANCIAL SCHEDULES

## A. Revenue Deficiency

Revenue Requirement Summary  
**Test Year Ending December 31, 2020**

<table>
<thead>
<tr>
<th>Description</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Rate Base</td>
<td>$ 32,617,028</td>
</tr>
<tr>
<td>Rate of Return</td>
<td>7.119%</td>
</tr>
<tr>
<td>Required Operating Income</td>
<td>$ 2,322,006</td>
</tr>
<tr>
<td>Operating Income</td>
<td>$(128,124)</td>
</tr>
<tr>
<td>Income Deficiency</td>
<td>$ 2,450,130</td>
</tr>
<tr>
<td>Gross Revenue Conversion Factor</td>
<td>1.403351</td>
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<tr>
<td>Gross Revenue Deficiency</td>
<td>$ 3,438,392</td>
</tr>
<tr>
<td>GUIC in current rates</td>
<td>$ 790,153</td>
</tr>
<tr>
<td>Net increase in required recovery.</td>
<td>$ 2,648,239</td>
</tr>
</tbody>
</table>
### B. Rate Base Summary

**Rate Base Summary**  
**Test Year Ending December 31, 2020**

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Plant in Service</td>
<td>$66,360,621</td>
</tr>
<tr>
<td>Accum. Reserve for Depreciation</td>
<td>($31,359,894)</td>
</tr>
<tr>
<td>Net Gas Plant in Service</td>
<td>$35,000,727</td>
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<tr>
<td><strong>Additions:</strong></td>
<td></td>
</tr>
<tr>
<td>Materials and Supplies</td>
<td>$516,104</td>
</tr>
<tr>
<td>Gas in Underground Storage</td>
<td>$254,020</td>
</tr>
<tr>
<td>Prepayments</td>
<td>$139,258</td>
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<tr>
<td>Unamortized Loss on Debt</td>
<td>$56,258</td>
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<tr>
<td>Unamort. Redemption Cost-Pref.</td>
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<tr>
<td>Stock</td>
<td>$10,034</td>
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<tr>
<td><strong>Total Additions</strong></td>
<td>$975,674</td>
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<tr>
<td><strong>Deductions:</strong></td>
<td></td>
</tr>
<tr>
<td>Accumulated Deferred Income</td>
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</tr>
<tr>
<td>Taxes</td>
<td>$2,568,564</td>
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<tr>
<td>Customer Advances</td>
<td>$790,809</td>
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<tr>
<td><strong>Total Deductions</strong></td>
<td>$3,359,373</td>
</tr>
<tr>
<td><strong>TOTAL AVERAGE RATE BASE</strong></td>
<td>$32,617,028</td>
</tr>
</tbody>
</table>
### C. Operating Income Summary

**Operating Income Summary**  
**Test Year Ending December 31, 2020**

<table>
<thead>
<tr>
<th>Description</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>OPERATING REVENUES</strong></td>
<td></td>
</tr>
<tr>
<td>Sales</td>
<td>$ 21,153,840</td>
</tr>
<tr>
<td>Transportation</td>
<td>$ 1,915,879</td>
</tr>
<tr>
<td>Other Operating Revenue</td>
<td>$ 235,536</td>
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<tr>
<td><strong>Total Operating Revenues</strong></td>
<td><strong>$ 23,305,255</strong></td>
</tr>
<tr>
<td><strong>OPERATING EXPENSES</strong></td>
<td></td>
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<td>Operation and Maintenance</td>
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<td>Cost of Gas</td>
<td>$ 13,070,526</td>
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<td>Other O&amp;M</td>
<td>$ 6,866,332</td>
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<td><strong>Total O&amp;M</strong></td>
<td><strong>$ 19,936,858</strong></td>
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<td>Depreciation</td>
<td>$ 2,825,562</td>
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<td>Taxes Other than Income Taxes</td>
<td>$ 1,229,308</td>
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<td>Income Taxes</td>
<td>$(558,349)</td>
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<tr>
<td><strong>Total Expenses</strong></td>
<td><strong>$ 23,433,379</strong></td>
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<tr>
<td><strong>Operating Income</strong></td>
<td>$(128,124)</td>
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ORDER

1. The Commission adopts the ALJ’s Findings of Fact, Conclusions of Law, and Recommendations to the extent that the ALJ’s Report is consistent with the decisions herein.

2. Test year expenses shall be reduced by $11,500 for dues paid to Minnesota Utility Investors and $464 for Edison Electric Institute.

3. Great Plains shall file an annual report on incentive compensation and refund to ratepayers all incentive compensation amounts approved by the Commission and included in base rates that are not paid out to employees under the program. To determine the amount of actual incentive compensation paid that is recoverable from ratepayers, the Company shall apply the 15 percent cap to each employee’s salary. The annual Incentive Compensation Report shall include at a minimum the following:
   a. A description of the incentive compensation plan;
   b. The accounting of amounts of unpaid incentive compensation built into rates to be returned to ratepayers;
   c. An evaluation of the incentive plan’s success in meeting its stated goals, including the payout ratio;
   d. A proposal for refund, if applicable; and
   e. Identification of each performance indicator and its associated scorecard information, such as the measure, the goal for various attainment levels (threshold, target, maximum), its funding weight and the actual result achieved; and to report the overall plan payout percentage attained relative to the target goal of 100%.

4. The Commission adopts the following corrections to the ALJ’s: Page 4 – Summary of Recommendation, Findings of Fact 134, and Recommendation 8:
   a. [Page 4 – Summary of Recommendation] Finally, the Judge recommends that the Company’s proposed Conservation Improvement Program (CIP) expense of $566,621 be used as the basis for its Conservation Cost Recovery Adjustment (CCRA) Charge (CCRC) rate and that any changes to the Conservation Cost Recovery Adjustment (CCRA) factor should be determined in the Company’s next annual CIP tracker and financial incentive proceeding, rather than in the instant rate case.
   b. [Findings of Fact] 134. Based upon this data, the DOC-DER concluded that the Company’s proposal of $566,621 was reasonable to include in the 2020 test year CIP expenses, because that amount reflects actual 2018 CIP expenditures.218 The DOC-DER further opined that it would be unreasonable for the Company to include in the test year expenditures the amounts that GP budgeted for 2019 because, historically, the Company spent less than budgeted.219
Moreover, any amounts incurred over the 2018 actual expenses incurred could be collected through the CCRAC Factor each year.

c. [Recommendation] 8. Use the Company’s proposed CIP expense of $566,621 as the basis for its CCRAC rate and require that any changes to the CCRA factor be determined in the Company’s next annual CIP tracker and financial incentive proceeding.

5. Great Plains shall update the interest synchronization adjustment based on the Commission’s decisions in this case.

6. The Commission adopts the following capital structure, costs of debt and equity, and resulting overall cost of capital:

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<th>Component</th>
<th>Ratio</th>
<th>Cost</th>
<th>Weighted</th>
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<tr>
<td>Long-Term Debt</td>
<td>45.132%</td>
<td>4.712%</td>
<td>2.126%</td>
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<tr>
<td>Short-Term Debt</td>
<td>4.053%</td>
<td>3.693%</td>
<td>0.150%</td>
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<tr>
<td>Common Equity</td>
<td>50.815%</td>
<td>9.53%</td>
<td>4.843%</td>
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<tr>
<td>Total</td>
<td>100.000%</td>
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<td>7.119%</td>
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7. The Commission adopts the ALJ’s recommendations concerning the Sales Forecast and Class Cost of Service Study, and:

a. accepts GP’s sales forecast for test year 2020 as reasonable;

b. requires GP to retain the data for customers even if there is a change in the rate structure;

c. continues the compliance requirements set forth in Paragraph 16 of the 2016 Order; and

d. incorporates the following corrections/modifications to the ALJ’s Findings into the Order:

i. correct the following typographical errors in Para 305:
   
   2020 projected total customers: 22,028
   
   2020 projected total transportation: 4,675

ii. modify Para. 324 by incorporating the Department’s modifications as follows:

   324. Because of the lack of data available before 2004 and between 2004 and 2007, the DOC-DER also recommends that the Commission require GP to retain customer data such that, in the event the Company proposes different rate structures in the future, past data would remain available, to compare the different rate structures in subsequent rate cases. That is, going-forward, just because the Company decides to change the rate structure
does not mean the customer’s historical consumption data has changed or becomes unusable. GP agrees to this recommendation.

8. The Commission accepts Great Plains’s agreement to incorporate the following changes to its proposed CCOSS in its next general rate case:

   a. classify and allocate Land and Land Rights (FERC Account No. 374) on the same basis as Distribution Plant;

   b. classify and allocate Structures and Improvements (FERC Account No. 375) on the same basis as Distribution Plant;

   c. classify and allocate Maintenance of Structures and Improvements (FERC Account No. 886) on the same basis as Distribution Plant;

   d. classify and allocate Other Equipment (FERC Account No. 387) on the same basis as Distribution Plant;

   e. identify the customer classes that use special and expensive installations of measuring and regulating station equipment located on the distribution system and allocate the costs of Industrial Measuring and Regulating Station Equipment (FERC Account No. 385) and Maintenance of Measuring and Regulating Station Equipment-Industrial (FERC Account No. 890) to only those classes; and

   f. identify the customer classes that use large measuring and regulating stations located on local distribution systems and allocate the costs of Measuring and Regulating Station Expenses-Industrial (FERC Account No. 876) to only those classes;

   g. allocate Maintenance of Services (FERC Account No. 892) on the same basis as Services (FERC Account No. 380);

9. The Commission adopts ALJ findings 350 and 356 modified as follows:

   a. 350. As a result, the DOC-DER recommended against approval of the two minimum-size methods, as initially proposed filed by GP (MS1 and MS2).621 The DOC-DER also recommended that GP provide, in its rebuttal testimony, an improved minimum-size method (the MS3) using the current unit replacement cost (per foot) of the installed distribution pipes for each pipe type and size. Finally, the DOC-DER recommended that GP provide a revised medium minimum-size CCOSS using the outcome of the revised minimum-size method, with the adjustments to the classification and/or allocation of the FERC accounts that the DOC-DER recommended.

   b. 356. Finally, the Commission should require the Company to perform an improved minimum-size CCOSS using reliable and supported per-foot replacement costs for each type and size of installed distribution pipes, and file such a study in the next general rate case, as recommended by the DOC-DER.
10. The Commission will approve a revenue apportionment that maintains the revenue apportionment established in the 2016 Order.

11. The Company’s proposed basic customer service charge increase and daily basic charge calculation method are not approved. The Commission approves a $230 basic customer charge for the new Interruptible Grain Drying class.

12. The Commission approves Great Plains’s Levelized Annual Revenue Requirement (LARR) Factor and Maximum Allowable Investment (MAI) changes. Great Plains shall update the LARR and MAI changes to reflect the Commission’s final order on the Company’s proposed margin sharing credit and any changes to the GUIC revenues.

13. Great Plains shall make the following compliance filings within 30 days of the date of the final order in this docket:
   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 of 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;
      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.

14. Great Plains shall file 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, and if final authorized rates are lower than interim rates, a proposal to make refunds of interim rates, including interest to affected customers.
15. Comments on all compliance filings are authorized within 30 days of the date they are filed. However, comments are not necessary on Great Plains’s proposed customer notice.

16. The suspension period under Minn. Stat. § 216B.16, subd. 2(f), is extended to allow an additional 60 days, until October 26, 2020, to make a final determination in this case.

17. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

[Signature]

Will Seuffert
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 or speech impairment may call using their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.
CERTIFICATE OF SERVICE

I, Nancy Jia, hereby certify that I have this day, served a true and correct copy of the following document to all persons at the addresses indicated below or on the attached list by electronic filing, electronic mail, courier, interoffice mail or by depositing the same enveloped with postage paid in the United States mail at St. Paul, Minnesota.

Minnesota Public Utilities Commission
FINDINGS OF FACT, CONCLUSIONS, AND ORDER

Docket Number

G-004/GR-19-511

Dated this 26th day of October 2020

/s/ Nancy Jia
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<tr>
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<tr>
<td>Tamie</td>
<td>Aberle</td>
<td><a href="mailto:tamie.aberle@mdu.com">tamie.aberle@mdu.com</a></td>
<td>Great Plains Natural Gas Co.</td>
<td>400 North Fourth Street Bismarck, ND 585014092</td>
<td>Electronic Service</td>
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<tr>
<td>Peter</td>
<td>Beithon</td>
<td>pbeithon@otpcocom</td>
<td>Otter Tail Power Company</td>
<td>P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496</td>
<td>Electronic Service</td>
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<tr>
<td>James J.</td>
<td>Bertrand</td>
<td><a href="mailto:james.bertrand@stinson.com">james.bertrand@stinson.com</a></td>
<td>STINSON LLP</td>
<td>50 S 6th St Ste 2600 Minneapolis, MN 55402</td>
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<tr>
<td>Ray</td>
<td>Choquette</td>
<td><a href="mailto:rchoquette@agp.com">rchoquette@agp.com</a></td>
<td>Ag Processing Inc.</td>
<td>12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047</td>
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<td>Sharon</td>
<td>Ferguson</td>
<td><a href="mailto:sharon.ferguson@state.mn.us">sharon.ferguson@state.mn.us</a></td>
<td>Department of Commerce</td>
<td>85 7th Place E Ste 280 Saint Paul, MN 551012198</td>
<td>Electronic Service</td>
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<td>Katherine</td>
<td>Hinderlie</td>
<td><a href="mailto:katherine.hinderlie@ag.state.mn.us">katherine.hinderlie@ag.state.mn.us</a></td>
<td>Office of the Attorney General-DOC</td>
<td>445 Minnesota St Suite 1400 St. Paul, MN 55101-2134</td>
<td>Electronic Service</td>
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<tr>
<td>Brian</td>
<td>Meloy</td>
<td><a href="mailto:brian.meloy@stinson.com">brian.meloy@stinson.com</a></td>
<td>STINSON LLP</td>
<td>50 S 6th St Ste 2600 Minneapolis, MN 55402</td>
<td>Electronic Service</td>
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<tr>
<td>Ann</td>
<td>O'Reilly</td>
<td><a href="mailto:ann.oreilly@state.mn.us">ann.oreilly@state.mn.us</a></td>
<td>Office of Administrative Hearings</td>
<td>PO Box 64620 St. Paul, MN 55101</td>
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<td>Residential Utilities Division</td>
<td><a href="mailto:residential_utilities@ag.stat">residential_utilities@ag.stat</a>@e.mn.us</td>
<td>Office of the Attorney General-RUD</td>
<td>1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131</td>
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<td>Will</td>
<td>Seuffert</td>
<td><a href="mailto:Will.Seuffert@state.mn.us">Will.Seuffert@state.mn.us</a></td>
<td>Public Utilities Commission</td>
<td>121 7th Pl E Ste 350 Saint Paul, MN 55101</td>
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<tr>
<td>Janet</td>
<td>Shaddix Elling</td>
<td><a href="mailto:jshaddix@janetsaddix.com">jshaddix@janetsaddix.com</a></td>
<td>Shaddix And Associates</td>
<td>7400 Lyndale Ave S Ste 190 Richfield, MN 55423</td>
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<td>Byron E.</td>
<td>Starns</td>
<td><a href="mailto:byron.starns@stinson.com">byron.starns@stinson.com</a></td>
<td>STINSON LLP</td>
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<td>Xcel Energy</td>
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