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 Petition by Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota

ISSUE DATE: September 6, 2016

DOCKET NO. G-004/GR-15-879

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

PROCEDURAL HISTORY

I. Initial Filings and Orders

On September 30, 2015, Great Plains Natural Gas Company, a Division of MDU Resources Group, Inc., filed this general rate case. The Company asked to increase Minnesota retail natural-gas rates by some $1,580,000, or approximately 6.4%, 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 Great Plains Natural Gas Company (Great Plains), a Division of MDU Resources Group, Inc. Petition to Establish a New Base Gas Cost Filing for Interim Rates in Great Plains' General Rate Case, Docket No. G-004/GR-15-879*, Docket No. G-004/MR-15-878, Order Setting New Base Cost of Gas (November 30, 2015).

II. The Parties and Their Representatives

The following parties appeared in this case:

- Great Plains Natural Gas Company, a Division of MDU Resources Group, Inc. (Great Plains or the Company), represented by Brian M. Meloy, Stinson Leonard Street LLP.

- Minnesota Department of Commerce (Department), represented by Julia E. Anderson and Peter E. Madsen, Assistant Attorneys General.

- Office of the Minnesota Attorney General–Residential Utilities and Antitrust Division (OAG), represented by Joseph A. Dammel and Ryan P. Barlow, Assistant Attorneys General.

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Barbara J. Case 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 April 7, 2016. After the hearing the parties filed initial briefs, reply briefs, and proposed findings of fact.

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

- Lyon County Library, Marshall—March 9, 2016

- City Council Chambers, Fergus Falls—March 9, 2016

IV. Public Comments

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

No members of the public attended the public hearing held in Marshall. Three members of the public attended the public hearing held in Fergus Falls, and all three spoke.

One person wanted to explore the possibility of recouping some portion of the gas-extension charges he had paid to have service brought to his home in 2010, as new homeowners in the area were now joining the system. He and the Company agreed to discuss the issue after the public hearing.

The other two members of the public objected to the rate increase and urged careful scrutiny of the Company's numbers and spending practices. One or both expressed concern about the following issues: conservation costs and their recovery, the Company's transactions with its affiliates, the Company's proposal to increase the monthly customer charge, executive compensation, the proposed consolidation of the Company's two Purchased-Gas-Adjustment areas and rate areas, the sense that utility rate increases were outstripping inflation and Social Security cost-of-living adjustments, and why natural-gas surpluses did not appear to translate into lower utility rates.

Three members of the public filed written comments, all opposing the rate increase as excessive and burdensome. These commentators, too, questioned the need for a rate increase in light of natural-gas surpluses and dropping natural-gas prices.

The Administrative Law Judge categorized and summarized the public comments in her report, and 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 June 30, 2016, the Administrative Law Judge filed her Findings of Fact, Conclusions of Law, and Recommendation (the ALJ's Report). All parties filed exceptions to the ALJ's Report under Minn. Stat. § 14.61 and Minn. R. 7829.2700.

On August 2 and 5, 2016, the Commission heard oral argument from and asked questions of the parties. On August 5, 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.

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

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

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

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]

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,

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[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.

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

II. Rate Case Overview

Great Plains seeks an annual rate increase of $1,578,615, or 6.4%, to cover a revenue deficiency due mainly to declining customer usage and significant investments in a new customer billing system, an automatic meter-reading system, and new distribution infrastructure. The Company has not had a rate increase since the one granted in its last rate case in 2004.

The Company also seeks to consolidate its two Purchased-Gas-Adjustment areas and its two rate areas, because its distribution network has become more integrated, its supply portfolio no longer differs significantly by geographic area, and the costs of serving both areas are now the same or very similar.

The Company proposed to increase fixed monthly charges and to shift more revenue responsibility to the residential class, claiming that the cost of serving that class substantially exceeded the portion of the revenue requirement allocated to it. And it proposed a pilot revenue decoupling program, to separate its revenue from changes in energy sales and reduce its disincentive to encourage conservation.

The Company used a projected 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), all based on actual 2015 data through October 31, 2015. It filed revised projected data for the last two months of 2015.

III. Summary of the Issues

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

1) Should the Company consolidate the separate base costs of gas from its north and south districts into one unified base cost of gas rate—and if so, how?

2) Should the Company change how it recovers and credits its demand-related gas costs—and if so, how?

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

3) Should the Company recover its Unamortized Loss on Debt and related deferred taxes in rate base—and if so, how?

On the first issue, the parties and the ALJ agreed that consolidation was appropriate; the Commission concurs, as discussed below.

The second issue relates to Class-Cost-of-Service-Study and rate-design determinations and is discussed in both contexts below.

The third issue—rate-base recovery of unamortized loss on debt and of related deferred taxes—was resolved by the parties during evidentiary hearings, with the ALJ concurring.[8] The Commission agrees that the record supports that resolution and adopts it.

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.[9] The Commission concurs.

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

Financial Issues

- ***Updated 2015 Data and the Test Year Rate Base and Depreciation Expense—***Should test-year rate base be adjusted to correspond to updated but still partially projected 2015 data?

- ***Updated 2015 Data and Other Operation and Maintenance (O&M) Expenses—***Should the test-year O&M expense be updated to correspond to updated but still partially projected 2015 data?

- ***Pension Expense—***Has the Company demonstrated that its test-year pension expense is reasonable and prudent?

- ***Amortization Period for Rate-Case Expense—***Over what time period should the costs of this rate case be amortized?

- ***Incentive Compensation—***Has the Company demonstrated that it is reasonable and prudent to include executive bonuses and commissions in its test-year expense for incentive compensation?

- ***Expenses of Highest-Paid Officers and Employees—***Did the Company properly account for the compensation and expenses of two of its ten highest-paid officers and employees, given their pre-test-year departure from the Company and subsequent replacement?

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[8] ALJ's Report ¶¶ 63-68.

[9] *Id.*, Conclusion of Law 5.

- ***American Gas Association and Minnesota Chamber of Commerce Dues—***Has the Company demonstrated that it should be permitted to recover from ratepayers any or all of its test-year dues to the American Gas Association or the Minnesota Chamber of Commerce?

- ***Sales Forecast—Weather Normalization and Historical Sales Data—***Has the Company demonstrated that it is reasonable and prudent to rely on weather data for the period from 1971 to 2000 to develop its sales forecast? Has the Company demonstrated that it is reasonable and prudent to rely on sales data from 2012 to 2014?

Cost-of-Capital Issues

- ***Common Equity Ratio—***Has the Company demonstrated that its proposed 50.586% equity ratio is just and reasonable?

- ***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 Issues

- ***Adequacy of Company's Class Cost of Service Study—***Has the Company demonstrated that its Class Cost of Service Study has the factual support and methodological soundness to function as a useful resource in the rate-design portion of this rate case?

Rate-Design Issues

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

- ***Customer and Distribution Charges—***At what levels should the Commission set the fixed customer charges for the Company's seven customer classes? At what level should the Commission set the volumetric distribution charges?

- ***Eligibility of Two Specific Customers for Flexible Rates—***Do two specific customers, identified in the record as "Customer A" and "Customer B," meet the eligibility requirements for flexible rates under Minn. Stat. § 216B.163?

- ***Consolidation of North and South PGA Districts and North and South Rate Districts—*** Should the Commission approve the Company's proposal, accepted by the parties and the ALJ, to consolidate its two PGA districts and its two rate districts?

- ***Caps on Surcharges or Refunds Under Proposed Revenue Decoupling Mechanism—***If the Commission approves the Company's proposed, pilot revenue-decoupling program, should it cap the annual refunds or surcharges due customers under the program and, if so, should the caps be symmetrical?

- ***Standby Service Tariff—***Should the Company be permitted to eliminate its Standby Service tariff?

- ***Revenue Adjustment for First-Through-the-Meter Proposal*—**Should the Commission adjust projected revenue upward to reflect the new first-through-the-meter billing option?

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 a full day of formal evidentiary hearings and two public hearings. She reviewed the testimony of 17 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 552 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. Updated 2015 Data and the Test Year Rate Base

A. Introduction

Great Plains proposed a test year rate base of $16,836,799.[10] It based this initial projection on 2014 actual financial data and 2015 projected data. During the contested case, the Company filed an update that included 10 months of actual 2015 data (the 2015 update). The updated data reflected a 2015 rate base $212,888 lower than initially projected.

The OAG argued that the 2016 rate base should be reduced by $212,888 to match the reduction in the 2015 rate base projection.

B. Positions of the Parties

The OAG argued that it would be appropriate and more accurate to reflect the 2015 update in the test year. In this case, that would call for a $212,888 reduction in the test year rate base.

[10] The rate base is the net value of approved utility investments, which will be used to calculate the utility's total revenue requirement.

The Company disagreed, and argued that the 2015 update was intended only as a check on the reasonableness of the Company's initial projections. Because the 2015 update included only 10 months of actual data and two months of estimates, the Company contended, it should not be used as a basis for modifications to the initial test year rate base projection. According to the Company, increases in costs or investment over the final two months of 2015 could offset the apparent decline.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission adopt a reduction of $187,944, based on the updated rate base figures.[11]

D. Commission Action

The Commission will not require the Company to adjust its test year rate base to correspond to changes reflected in the 2015 update. The 2015 update provides useful information to evaluate the reasonableness of the Company's initial projections, but the Commission will use it for that limited purpose and will not require the updated data to be used in lieu of those projections. The Commission finds that a possible—not actual—1.6% difference in projected 2015 rate base does not warrant an adjustment, but rather validates Great Plains' original projection in light of Great Plains' near-term planned investment in rate base.

Accordingly, the Commission will adopt the 2016 test year rate base as proposed by Great Plains. For these same reasons, the Commission will also accept the test year depreciation expense of $1,729,126 as proposed by Great Plains.

VI. Updated 2015 Data and Other Operation and Maintenance (O&M) Expenses

A. Introduction

Utilities incur certain costs such as labor, chemicals, information technology, maintenance, and licensing, that they classify as "Other" Operation and Maintenance Expenses. Great Plains proposed $6,095,020 in Other O&M expenses in the test year.

Great Plains projected the test year expense amount based on an initial projection of $5,754,053 in 2015 Other O&M expenses. During the contested case proceeding, the Company submitted the 2015 update, which reduced the 2015 Other O&M expense amount to $5,629,217. The OAG recommended that the Company reduce its test year Other O&M expenses in light of the 2015 update.

At issue is whether the Company demonstrated that its test year Other O&M expense is reasonable and prudent.

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[11] The ALJ's Report characterized this reduction as proposed by the OAG, though it was smaller than the reduction the OAG in fact proposed. ALJ Finding 172 accurately stated the OAG's proposed $212,888 reduction.

B. Positions of the Parties

1. The OAG

The OAG argued that because 2015 Other O&M expenses identified in the company's updated data declined by $123,384, 2016 test year expenses should be reduced by the same amount. According to the OAG, the Company's updated data revealed that it overestimated its 2015 Other O&M expenses, and 2016 projected expenses should therefore be reduced.

2. The Company

Great Plains contended that the OAG's proposal was unreasonable. It argued that the OAG's proposed reduction disregarded other differences between the original 2015 projections and the 2015 update. Specifically, Great Plains argued, the OAG recommended adjustments for reduced costs in the 2015 update, but not adjustments for data reflecting increased costs or reduced revenues. The Company asserted that the 2015 update should be regarded as a check on the reasonableness of the original projections, which validated the reasonableness of the Company's projections.

C. The Recommendation of the Administrative Law Judge

Relying on the updated 2015 actual expense data, the ALJ found that $89,734 of the Company's Other O&M expenses for the 2016 test year were not demonstrated to be reasonable, and recommended excluding that amount. She concluded, however, that the Company adequately demonstrated that $33,650 in medical and dental expenses are reasonable and should be included in the test year.

D. Commission Action

The Commission will not require the Company to adjust its Other O&M expenses to correspond to changes in the 2015 update. The 2015 update provides useful information to evaluate the reasonableness of the Company's initial projections, but the Commission will use it for that limited purpose and will not require the updated data to be used in lieu of those projections. The Commission finds that the small variance between projected 2015 expenses and the 2015 update is minor and demonstrates the reasonableness of the Company's initial projections. Accordingly, the Company's projected 2015 expenses do not need to be modified.

Consistent with this determination the Commission will not adopt ALJ Finding 116, and will replace ALJ Finding 119 as set forth in the ordering paragraphs.

VII. Pension Expense

A. Introduction

The Company incurs annual costs to fund and administer defined benefit pension plans for union and non-union employees, though the plans are closed to new participants. The calculation of projected pension expenses requires actuarial assumptions appropriate for the pension plan in question. These assumptions include a discount rate (to calculate the present value of future liabilities) and a long-term growth rate for pension assets. Appropriate actuarial assumptions vary over time, but changes are only reflected in utility rates periodically—when a rate case is decided.

Great Plains proposed a test year pension expense of $11,292. The Department and the OAG both challenged the pension expense projection.

B. Positions of the Parties

Because the Company's historical pension expense amount has fluctuated significantly, the Department and the OAG argued that the test year expense amount should be projected using a five-year historical average. The Department argued that the discount rate underlying the Company's projection was too low for ratemaking purposes.

Both the Department and the OAG proposed to reduce Great Plains' test year pension expense by $3,891. The proposed reduction would allow for a test year pension expense of $7,401 on a Minnesota-jurisdictional basis.

The Company disagreed that a five-year average was appropriate for projecting its pension expense, and asserted that its original projection was demonstrated to be reasonable in light of its 2015 expense amount.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the use of a five-year average is reasonable, and therefore recommended that the Commission adopt the Department and OAG's recommended pension expense reduction.

D. Commission Action

The Commission strives in ratemaking to reflect actual costs as accurately as possible. But which tools are the most accurate is a fact-specific inquiry, and the answers vary from case to case. Averaging costs over time is a commonly used ratemaking tool to protect ratepayers and shareholders from the effects of test-year anomalies or risks associated with extremely volatile costs or revenues.

The Company's pension expense amount has been highly volatile from year to year. Over the past five years the actual expense amount has fluctuated between -$6,469 and +$16,320. In this case, an averaging approach appears to be a more reliable basis for determining test-year pension costs than one recent year of a highly volatile cost.

The Commission is persuaded that the 2016 projected expense amount should not be calculated using actuarial assumptions from a single point in time. The Commission therefore agrees with the ALJ's findings and recommendation, and will require that the test year pension expense be set at the five-year (2010-2014) average: $7,401.

VIII. Amortization Period for Rate-Case Expense

A. Introduction

Reasonable, prudently incurred rate case expenses are properly included in test year costs and built into rates for recovery from ratepayers. The Commission tries to set the cost-recovery (or, amortization) period—which determines the percentage of total rate case costs built into rates on an annual basis—to coincide with the time period between rate cases. It is important for these two time periods to match as closely as possible, to ensure that the utility recovers its authorized rate case costs without over-recovering them.

Setting the cost recovery period can be challenging, however, since individual utilities generally control the timing and frequency of rate case filings. Rate cases before this Commission have involved rate case intervals from two years to twenty years—and a two-year cost recovery assumption followed by a twenty-year rate case interval results in eighteen years of over-recovering rate case costs from ratepayers.

The Department challenged the Company's proposed amortization period for recovery of authorized rate-case expenses.

B. Positions of the Parties

The Company initially proposed to recover $525,000 of estimated current rate case expenses over a three-year amortization period, for a test-year rate case expense of $175,000.

The Company supported its proposal for a three-year amortization period by arguing that it anticipated a period of increased expenses and capital investment, and accordingly would likely file its next rate case in no more than three years.

The Department recommended a four-year amortization period, which would reduce the test-year expense amount by $43,750. This recommendation, the Department argued, was justified based on the company's historic average time between rate cases.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that a four-year amortization period is appropriate, and that therefore test year rate case amortization expenses proposed by the Company should be decreased by $43,750.

D. Commission Action

The Commission agrees with and adopts the ALJ's findings and recommendations on these issues. As detailed below, the Commission will approve the Company's rate case expense amount, to be amortized over a four-year period.

Though the historic average does not control the Company's future rate case timing decisions, it provides a basis for a reasonable estimate. In this case, a four-year amortization period is reasonable because the Company's historical average time between rate cases since Great Plains merged with MDU Resources Group is 3.75 years, and its overall average is 5.7 years.

The Commission will also require any over-recovery of the amount to be tracked for refund in a future rate case.

IX. Incentive Compensation

A. Introduction

Great Plains sought rate recovery of $182,080 in incentive compensation costs. The Department challenged a portion of those costs, arguing that the Company had not demonstrated that it is reasonable and prudent to include bonuses and commissions primarily associated with MDU Resources executives as a test-year expense.

B. Positions of the Parties

The Department contended that the Company's test year incentive compensation expense should be reduced by $89,032 because that amount represents bonuses and commissions paid to executives that have not been shown to benefit ratepayers.

The Company opposed the Department's proposed reduction. It argued that the Department had not demonstrated that the bonuses and commissions benefit only shareholders, and that the disputed amount included expenses that are appropriate for ratepayer recovery. Specifically, the Company asserted that its "health and wellness incentive" was included in the Department's proposed disallowance.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that the Company "failed to demonstrate that its bonuses and commissions are 'significantly based upon factors that are unrelated to earnings and stock price. Such incentive compensation is properly paid out of earnings, not by ratepayers.'"[12] The ALJ recommended reducing Great Plains test year incentive compensation by $89,032.

D. Commission Action

The Commission agrees with and will adopt the ALJ's findings and conclusions on this issue, and will reduce test year Employee Incentive Compensation by $89,032.

The burden of justifying this expense rests on the Company, and doubt must be resolved in the ratepayers' favor.[13] The Commission has historically regarded bonuses and commissions paid to executives as inappropriate for rate recovery, unless a utility demonstrates that those incentives serve to advance ratepayer interests. Great Plains has not established what, if any, of the amount challenged by the Department advances ratepayer interests.

The Company has not met its burden, and so the Department's recommended exclusion is appropriate. Because the record lacks evidence establishing a specific amount of the Department's proposed exclusion that served ratepayer interests, excluding $89,032 is warranted. The remaining $93,048 of allowed incentive compensation expense reasonably reflects rate-recoverable test-year incentive expenses that serve the ratepayer-oriented goals such as safety and operational efficiency.

X. Compensation and Other Expenses For Highest-Paid Officers and Employees

A. Introduction

Great Plains included $38,502 in test year expenses for travel, entertainment, and related employee expenses, including $4,170 for its ten most highly compensated officers and

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[12] ALJ's Report ¶ 138 (citation omitted).

[13] Minn. Stat. § 216B.03.

employees. The OAG argued for a reduction in test year expenses because two of the employees left prior to the test year.

B. Positions of the Parties

1. The OAG

The OAG argued that a reduction was warranted because two highly compensated employees, whose expenses were used to calculate the test year expense, were no longer employed by the Company. Further, the OAG argued, the Company double-counted expenses for employees already on the top-ten list who replaced the outgoing employees.

According to the OAG, the appropriate test-year expense reductions for removal of the two challenged employees would be $20,627 for compensation, and $1,592 for travel, entertainment, and related employee expenses.

2. The Company

Because the two positions occupied by the former employees would be filled in the test year, the Company argued there would be no reduction in expense. Accordingly, the Company asserted, the OAG's reduction was not justified. The Company also disputed that employee expenses were double counted—no new positions were created, the Company asserted, so expenses for the top ten positions were counted just once.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended no adjustment to the expense amount. She found no double counting and concluded that the Company will have similar expenses regardless which individual holds which specific position.

D. Commission Action

The Commission agrees with and adopts the ALJ's recommendation, and will not require the Company to make an adjustment to its test year expenses. It is reasonable and appropriate to account for expenses for the most highly compensated positions by position and not by tracking the individuals in those positions. The positions identified by the OAG were filled, and were not double counted, so the related expense amounts do not require an adjustment.

XI. American Gas Association and Minnesota Chamber of Commerce Dues

A. Introduction

Great Plains is a member of the American Gas Association (AGA), an energy trade association that compiles information and conducts research on behalf of its membership, as well as representing their interests in proceedings in state and federal legislative and regulatory proceedings. The AGA's activities include lobbying state and federal government policymakers. Great Plains sought to recover $9,072 in AGA dues for the test year.

The Company is also a member of the Minnesota Chamber of Commerce. Great Plains sought to recover in $522 Chamber of Commerce dues for the test year.

At issue is whether the Company should be permitted to recover AGA and Minnesota Chamber of Commerce dues from ratepayers.

B. Positions of the Parties

1. The OAG

The OAG objected to recovery of dues for the AGA and Minnesota Chamber of Commerce, and asserted that they are unreasonable and unnecessary for utility service. According to the OAG, the dues primarily go to support the organizations' lobbying efforts, and the record does not support a conclusion concerning what portion of the dues, if any, serve ratepayer interests. The OAG therefore recommended the Commission disallow any portion of the dues in the test year.

2. The Company

Great Plains argued that the AGA's primary function is not lobbying, and that it provides a number of other benefits to the Company and to ratepayers. The Company estimated that approximately 2.5% of AGA dues[14] and 60% of Chamber dues are related to lobbying and initially excluded the corresponding amount of such dues from test-year expenses. It argued that the OAG's assessment of the AGA's activities was based on a superficial analysis of the AGA's webpage.

After the evidentiary proceedings, the Company did not contest the OAG's recommendation to disallow 100% of the Chamber dues. It maintained its position that $9,072 of AGA dues should be included in the test year.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge concluded that neither AGA nor Chamber dues are appropriate for inclusion in recoverable test year costs. In particular, the ALJ found the Company's assertion that only 2.5% of AGA dues are attributable to lobbying is not credible, "in light of the evidence concerning the AGA's activities, location, and leadership."

D. Commission Action

The Commission agrees with and adopts the ALJ's recommendation on this issue. The burden of justifying this expense rests on the Company, and doubt must be resolved in the ratepayers' favor.[15] The Company has not established that its AGA or Minnesota Chamber of Commerce dues are reasonable and necessary for the provision of utility service. And the record is inadequate to support a conclusion about the portion of AGA dues that might serve ratepayer interests—the bare assertion that just 2.5% should be excluded is outweighed by the remainder of the evidence.

Absent a reliable method to determine the portion of a lobbying organization's dues that advance ratepayer interests, the Commission concludes that disallowance of the entire amount is the most reasonable way to protect ratepayers. Accordingly, the dues must be excluded from the Company's test year expenses.

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[14] Great Plains attributed the 2.5% estimate to information provided by the AGA.

[15] Minn. Stat. § 216B.03.

XII. Sales Forecast—Weather Normalization and Historical Sales Data

A. Introduction

Great Plains has proposed to use a forecasted test year for this case, and it used historical weather and sales data to forecast test year sales. An accurate sales forecast is critical to calculating the Company's revenue requirement. An inaccurate sales forecast could result in rates that are either unreasonably high or unreasonably low, producing a windfall or possible financial harm to the Company.

Revenue decoupling increases the significance of sales forecast accuracy for ratepayers. Divergence between actual sales and forecasted sales would result in over- or under-collection that will be tracked and annually rectified through a refund or a surcharge over the course of the following year. A more accurate sales forecast reduces the likelihood and magnitude of decoupling-related rate adjustments.

Weather has a substantial effect on sales to residential, commercial, and some industrial customers. Weather normalization adjusts the test year sales forecast to reflect "normal" weather conditions by relying on historical weather data.

At issue are whether:

- the Company has demonstrated that it is reasonable and prudent to rely on weather data for the period from 1971 to 2000 to develop its sales forecast, and
- the Company has demonstrated that, in developing its test-year sales forecast, it is reasonable and prudent to rely on sales data from 2012 to 2014.

B. Positions of the Parties

1. The Company

The Company proposed forecasting sales normalized with respect to a 30-year weather average, from 1971 to 2000. It argued that it uses a 30-year rolling average for other purposes, and asserted that it does so to reduce the effects of unseasonable weather on the calculations.

Great Plains also calculated its sales forecast using historical sales data from 2012 to 2014. It argued that a longer historical sales data period would inaccurately forecast higher usage because it would under-reflect recent conservation efforts undertaken by its customers—specifically "more aggressive conservation requirements" in recent years. It also argued that it uses a three-year historical data period for other regulatory purposes.

2. The Department

The Department objected to the Company's proposed time periods for its weather normalization and historical sales volume. It argued that the weather data was, at best, fifteen years out of date, and used too long a time span to be predictive. And, according to the Department, the proposed historical sales volume time period was not predictive because it was unreasonably short.

The Department stated that an updated, 20-year weather normalization period would provide more reliable predictions, but that the Company only provided data for a 16-year period. For that reason, it recommended that the Company use the most recent 16-year period (1999–2015) for weather normalization.

For the historical sales volume, the Department again stated it preferred a 20-year period, but based on available data recommended a 12-year period (2004–2015).[16] The Department argued that using a longer time period, and shortening the amount of time forecasted by including 2015 data, would result in more accurate sales predictions. The Department disagreed that the historical data would inadequately account for conservation.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed with the Department, and concluded that using the most recent 16-year period to estimate normal weather, and using 12 years of historical sales volumes to forecast test-year sales, would be most reliable and should be used in this case.

D. Commission Action

The Commission agrees with and adopts the ALJ's findings and recommendations on these issues. The weather-normalization period proposed by the Company is both out of date and stretches back too far, seriously compromising its usefulness for predicting weather in the test year. And the brevity of the Company's proposed historical sales data period limits its ability to serve as a reliable sales forecast.

The Department-recommended weather normalization and historical sales time periods will result in more reliable sales predictions. Accordingly, the Commission will require the Company to use a 16-year period (1999–2015) for weather normalization and a 12-year period (2004–2015) of historical sales for forecasting purposes.

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 contested cost-of-capital issues are capital structure and the cost of equity. The Company and the Department take the same position on capital structure, which differs from the OAG's, and all three parties take different positions on the cost of equity. The costs of long- and short-term debt are uncontested.

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

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[16] The Department stated that it "had some concerns about verifying 2015 data, but did not adjust the results of its recommendation based on 12 years." Response of the Department of Commerce to the Issues Matrix of Great Plains Natural Gas Co., 3 (May 20, 2016).

XIII. Capital Structure

A. Introduction

Great Plains is a division of MDU Resources Group, Inc. (MDU), a diversified natural resource company. 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 its parent company's actual capital structure, which did not differ significantly from the capital structures of utilities that were comparable to Great Plains. The Department agreed, contingent on the Company using MDU's 2016 updated capital structure instead of the 2015 capital structure proposed in its original rate-case filing. The updated 2016 capital structure is set forth below:

Long-Term Debt	41.712%
Short-Term Debt	6.556%
Preferred Stock	1.146%
Common Equity	50.586%

The OAG argued that the components of the Company's capital structure should be set at the average percentages for the eight companies in the proxy group the Company used in its Discounted Cash Flow (DCF) cost-of-equity study. Those averages are set forth below:

Long-Term Debt	42.861%
Short-Term Debt	6.483%
Preferred Stock	1.126%
Common Equity	49.530%

B. Positions of the Parties

1. The OAG

The OAG argued that the 50.586% common-equity ratio proposed by the Company and the Department was excessive, that they must show clear justification to set the ratio above the average for Great Plains' DCF proxy group, and that they had failed to do so. The division also argued that debt was currently available on very favorable terms, making higher-cost equity financing particularly inappropriate.

2. The Company and the Department

The Company and the Department argued that the parent company's actual capital structure was a better indicator of how Great Plains would or should finance its operations than the average capital structure of either party's DCF proxy group, given the actual connection between the two entities.

They pointed out that their proposed 50.586% common-equity ratio was within the range of the common-equity ratios of both proxy groups, which ran from 42% to 56%.[17] They also pointed out that the proposed ratio was lower than the ratios of three of the eight companies in the two

[17] Great Plains' Initial Brief at 6.

proxy groups (the two groups contained six of the same companies) and argued that both facts demonstrated the reasonableness of their proposed common-equity ratio.

Finally, they argued that the OAG was inconsistent in its support of the Company's proxy group, treating it as definitive for purposes of setting the common-equity ratio but rejecting it for purposes of setting the cost of equity.

C. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended accepting the capital structure proposed by the Company and the Department.

She found that using the parent company's actual capital structure was preferable to relying on averages and that the fact that the actual capital structure fell within the ranges of both the Department's and the Company's proxy groups confirmed its reasonableness. Finally, she found that there was scant record evidence on the current and future cost of debt at the levels proposed by the OAG, as well as inadequate evidence on the financial impact of moving the millions of dollars at issue from equity to debt financing.

D. Commission Action

The Commission concurs with the ALJ's findings and analysis and will adopt the capital structure she recommends.

Three of the eight equity ratios in the two proxy groups of record exceed Great Plains' proposed equity ratio. The proposed ratio therefore falls close to the median and comfortably within normal parameters for utilities with risk profiles similar to Great Plains. Further, the capital structure proposed by the Company and the Department is the actual capital structure of the parent company. While still a hypothetical capital structure for Great Plains—which is not a stand-alone utility—its strong empirical tie to Great Plains confirms its credibility and reasonableness.

One function of proxy groups is to provide a reasonableness check for actual capital structures and a sound factual basis for constructing hypothetical ones. Here, the proxy groups confirm the essential reasonableness of the proposed capital structure from either perspective, and the proposed capital structure will be approved.

XIV. 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*.[18]

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 Great Plains is a division 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 and based their analysis on groups of utilities they considered similar enough to Great Plains to serve as proxies in determining the Company's cost of equity. The two proxy groups were very similar, with the Company's group containing the Department's entire six-company group, plus two additional companies.

Both parties did thoroughgoing studies using the Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance. They 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 DCF analysis of the Standard & Poor's 500 and an analysis using the Bond Yield Plus Risk Premium Model (RP), which the Commission has historically relied on less heavily, considering it prone to volatile outcomes. Both the Company and the Department relied mainly on their DCF analyses, using the other models as reasonableness checks.

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, which is the classic version, and the two-growth DCF, which uses one growth rate for an initial period, followed by a different growth rate for the long term. Other DCF variants include the retention-growth model, which uses retained-earnings forecasts as a growth-rate metric, and the blended-growth model, which uses both retention-growth forecasts and earnings-growth projections.

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

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

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

C. Positions of the Parties

1. The Company

The Company recommended a return on equity of 10%, based on three full DCF analyses—classic, retention-growth, and blended-growth—backed up by a DCF analysis of the Standard & Poor’s 500, a CAPM analysis, and a Risk Premium analysis.

The Company relied most heavily on its three DCF analyses, recommending a cost of equity near the bottom of the third quartile of results for its classic model, or between the third and fourth quartile of the results for its retention-growth and blended-growth models. The Company argued that it was necessary to set the cost of equity above the mean for the companies in its proxy group, to account for increased business risks it faced because of (a) its small size; (b) a lack of geographic diversity in its service area; (c) a lack of economic diversity in its service area; and (d) a lack of diversity in its customer base.

The Company continued to support its recommendation of a 10% return on equity throughout the case and did not update its DCF inputs and final results in rebuttal testimony, as is usually done. Nor did it average the stock prices critical to the dividend-yield input over the 30-day trading period typically used, choosing a six-month period instead. Further, it averaged only the highest and lowest stock prices for each month of the six month period, instead of following the more common practice of averaging the stock prices for every trading day in the averaging period.

Finally, the Company, like the Department, added a flotation adjustment to its DCF results to reflect and recoup the cost of issuing stock.

2. The Department

The Department recommended a return on equity of 9.18%, 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 13-14 basis points.

The Department had originally recommended a return of 9.77%, 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 had fallen by some 59 basis points. While original and updated DCF results nearly always differ, this 59-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 growth-rate DCF inputs, adjusting its projected growth rate 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 argued that the Company’s failure to update its DCF data rendered its conclusions unreliable. The agency pointed out that the most recent data factored into the Company’s DCF model was eight months old and that some data was over a year old. The

Department argued that since rates are set prospectively and market conditions vary over time, it is important to use the most recent market information available.

The Department challenged the Company's use of a six-month trading period for averaging stock-price DCF inputs, arguing that the usual 30-day trading period was a much better indicator of current and near-term economic conditions, including stock prices. The agency also challenged the Company's practice of averaging only the highest and lowest monthly stock prices during the six-month trading period, saying this practice left the Company's analysis vulnerable to being skewed by outliers.

Finally, the Department rejected the Company's claim that its return on equity should reflect enhanced business risks posed by its size and the composition of its service area and customer base. The Department argued that the DCF model's proxy-group process ensured that the Company's risk profile was adequately reflected and factored into the overall analysis and that adjusting for isolated, company-specific characteristics cutting only in favor of a higher return would improperly skew the analysis.

3. The OAG

The OAG supported the Department's DCF analysis as the only reasonable analysis in the record, concurring in the agency's claims that methodological errors compromised the Company's DCF analysis and that there was no factual or analytical basis to adjust the cost of equity upward to reflect company-specific business risks.

The OAG challenged the Department and the Company's support for a flotation adjustment, however. The division argued that adding a flotation adjustment to the cost of equity would reimburse the Company for costs it had not incurred since 2004—the year of its parent's last public stock issuance—and that it did not expect to incur in the relevant future, as no public stock issuance was currently planned. Further, the division argued that the portion of stock issuance costs reasonably attributable to Great Plains, which accounts for less than 1% of MDU's revenue, was close to *de minimis.*

The OAG also maintained that utility investors understand that the company will incur issuance costs that reduce its proceeds below the total amount of the issuance and that these costs have already been factored into their investment decisions. Similarly, the division claimed that investors are generally aware of other costs and fees associated with stock issuances—such as brokerage fees—that are not separately factored into the cost of equity, and are not troubled by their absence from the return-on-equity calculation.

Finally, the OAG pointed out that some regulatory agencies, including the Federal Energy Regulatory Commission, do disallow flotation adjustments if no public stock offering is imminent, demonstrating that disallowing these adjustments is a reasonable regulatory practice.

D. The Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended a return on equity of 9.06%, the Department's recommended return minus the flotation adjustment. She summarized her findings, conclusions, and recommendation as follows:

> The Administrative Law Judge finds that the cost of equity of 9.18 percent recommended by the DOC-DER is fully supported by careful analysis based on the most relevant data available for consideration. The Administrative Law Judge concludes that Great Plains' cost of equity should be set according to the analysis of the DOC-DER, with an adjustment to remove flotation costs.[19]

The ALJ found that both parties' models were broad and thorough, but that the Department's decision to update its DCF analysis with the most recent market data available—and to draw that data from a 30-day trading period—was consistent with Minnesota regulatory practice and yielded a more reliable result than the older data and six-month trading period used by the Company.

She rejected the Company's proposal to raise its return on equity to reflect company-specific business risks, concurring with the Department that the DCF proxy-group process ensured that the Company's overall risk profile was properly reflected and factored into the cost-of-equity.

She concurred with the OAG that the cost of equity should not include a flotation adjustment, since there were no recent or imminent public stock issuances presenting costs for recovery and no evidence in the record on the amount or impact of previous or future issuance costs.

E. Commission Action

1. Introduction

The Commission accepts, adopts, and incorporates the findings, conclusions, and recommendations of the Administrative Law Judge on the cost of equity.

The Commission concurs with the ALJ that the Department's cost-of-equity studies are methodologically transparent, analytically sound, ably executed, and supported by substantial evidence in the record. The Commission agrees that these studies represent the best evidence in the record on the cost of equity and should be adopted, with the exception of their inclusion of a flotation adjustment.

The proposed flotation adjustment and the other major contested issues—the market-data averaging period and the proposed adjustment for Company-specific risks—are discussed below.

2. The Market-Data Averaging Period

The Department's use of a 30-day trading period for its DCF inputs—and its updating of those inputs with the most recent market data available at the close of the evidentiary record—are consistent with sound and longstanding Minnesota practice. Both actions follow the fundamental financial principle that the most recent market information is normally the most reliable indicator of the current market expectations on which the cost of equity is based.

The Company's reliance on market data ranging from eight to twelve months old, its use of a six-month trading period, and its decision to include only the six highest and six lowest monthly stock prices in its averaging significantly undermine the usefulness of its DCF results. Its data is

[19] ALJ's Report ¶ 253.

dated, its data points limited, and its averaging period more firmly rooted in history than in the future. Rates have to be set prospectively, and the best available evidence of ongoing market conditions is normally the market conditions prevailing at the time of decision-making.

Of course, setting the cost of equity is fact-intensive and record-specific, and clearly anomalous market conditions might call for a departure from the use of an updated 30-day trading period for deriving DCF inputs. Here, the Company pointed to a larger than usual disparity between the Department's initial and updated DCF results.

The ALJ found, however, that the disparity was rational and explicable, caused by changes in the stock prices and dividends of the companies in the proxy group, as well as by updated growth forecasts by the investment firms used in the analytical models. She found these adjustments "of note but not anomalous in the market,"[20] and the Commission concurs.

For all these reasons, the Commission concurs with the ALJ that the Department's use of the most recent 30-day trading period for its final DCF inputs was reasonable and yielded a reliable result.

3. The Proposed Adjustment for Company-Specific Risks

The Company adjusted its DCF results upward to reflect business risks it said were unique to the Company, setting it apart from the companies in its proxy group: its small size, a lack of geographic diversity in its service area, a lack of economic diversity in its service area, and a lack of diversity in its customer base. 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.

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.

For all these reasons, the Commission concurs with the ALJ that the cost of equity should not be increased to reflect Company-specific business risks.

[20] ALJ's Report, ¶ 250.

4. The Flotation Adjustment

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 the proceeds paid to the company. Flotation costs in the amount of these fees are sometimes added to the cost of equity to credit the company with the full amount of the issuance.

Both the Department and the Company recommended adding flotation costs to the return on equity set in the case, but the ALJ demurred, finding

> The Administrative Law Judge agrees with the OAG that Great Plains has not demonstrated the need for flotation costs to be added to Great Plains' cost of equity. MDU, Great Plains' parent, has not issued stock since 2004. Great Plains did not offer evidence of the financial impact of issuance costs in that or any other MDU stock issuance. There is no showing that Great Plains, or MDU, plan a stock issue in the near future. The Administrative Law Judge concludes that an upward flotation cost adjustment to cost of equity has no basis in evidence and should not be allowed.

The Commission concurs that this record does not support the addition of flotation costs to the cost of equity. The record demonstrates that Great Plains' parent company has not had a public stock offering since 2004 and that it has no plans for a public stock issuance in the foreseeable future.

The Company offered no evidence on the actual amount or ongoing financial impact of the costs incurred in connection with earlier stock issuances. It relied instead on the argument that a flotation adjustment was required to prevent capital dilution and ensure a reasonable opportunity for the Company to earn its authorized rate of return.

The Commission concurs with the OAG, however, that utility investors understand that any company in which they invest will incur issuance costs that reduce its proceeds below the total amount of the issuance and that these costs are factored into their investment decisions. Similarly, investors understand that other costs and fees associated with stock issuances—such as brokerage fees—are not separately factored into the cost of equity, and are not deterred by their absence from the return-on-equity calculation.

Further, the Company has stated that it intends to file another rate case within three years of this one.[21] At that point it will have ample opportunity to demonstrate on the record the nature, amount, and financial impact of all costs associated with any completed or planned stock issuance. In the absence of that kind of factual detail, the Commission will disallow a flotation adjustment in this case and set the Company's cost of equity at 9.06%, the figure resulting from the Department's analysis, minus the flotation adjustment.

[21] ALJ's Report, ¶ 121.

5. The Company's Unadjusted DCF Results

Finally, the Commission notes that the results of the Company's own DCF analysis, prior to its proposed adjustments for Company-specific business risks and flotation costs, support a 9.06% cost of equity. The median returns on equity from its three DCF analyses average 8.48%, and the third-quartile returns on equity average 9.07%.[22]

These results further confirm the reasonableness of the 9.06% return recommended by the Department and the Administrative Law Judge.

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

The Company initially proposed a long-term debt cost of 5.777%, which it updated to 5.492% in the course of evidentiary proceedings. The Department concurred in the 5.492% figure, and the OAG did not address the issue.

The Company initially proposed a short-term debt cost of 2.274%, which the Department challenged as excessive. The Department pointed out that 2.274% was double the Company's projected 2015 short-term debt cost and triple its actual 2015 short-term debt cost. The agency calculated an alternative cost of 1.610%, based on record evidence, and the Company acquiesced. The OAG did not address the issue.

No one challenged the reasonableness of either of these agreed-upon numbers. The Commission concurs that they are reasonable and supported by substantial evidence; the Commission will set the cost of long-term debt at 5.492% and the cost of short-term debt at 1.610%.

In its exceptions, the Department proposed that the Commission adopt supplemental findings to clarify the evidentiary basis for these two numbers. The Commission concurs and adopts the findings proposed by the Department, set forth below:

Supplemental Findings on the Cost of Long-Term Debt

> *In its initial filing, Great Plains proposed a cost of long-term debt of 5.777 percent that reflected a projected issuance of a $150 million note with a 30-year term and a 5 percent interest rate. DOC Ex. 204 at 38 (Addonizio Direct). In its response to DOC Information Request No. 210, Great Plains explained that it issued three notes during 2015 totaling $150 million, with terms of 10 years, 15 years, and 30 years, and interest rates of 3.78 percent, 4.03 percent, and 4.87 percent, respectively. DOC Ex. 204 at 38, CMA-RD-10 (Addonizio Direct).*
>
> *Because those interest rates are lower than the projected rate of 5.00 percent, Great Plains cost of long-term debt fell to 5.492 percent in the updated Statement D provided in response to DOC Information Request No. 209. Id. at CMA-RD-5. The Department reviewed Great Plains calculations of its proposed cost of long-term debt and concluded that the calculations are reasonable. Id. at 38.*

[22] Ex. JSG-2, Schedule 4 (Gaske Direct) at 6-8.

Supplemental Findings on the Cost of Short-Term Debt

Unlike Great Plains' proposed long-term debt, the Department concluded that Great Plains had not demonstrated that its proposed short-term cost of debt is reasonable (i.e. not unreasonably high). DOC Ex. 204 at 37 (Addonizio Direct).

As shown in its initial filing, Great Plains assumed an interest rate of 1.873 percent on its short-term debt during test-year 2016. GP Ex. 2 at Statement D, Schedule D-1, p. 2 (Initial Filing). Great Plains also included in its cost of short-term debt the expense associated with the amortization of fees associated with its revolving credit facility. Id.; DOC Ex. 204 at 36 (Addonizio Direct). Adding these amortization fees raised the cost of short-term debt from 1.873 percent to 2.274 percent. DOC Ex. 204 at 36 (Addonizio Direct).

The Department agreed that it is reasonable for Great Plains to include an expense component for fees in the calculation of its cost of short- term debt. Id. The Department did not agree, however, with the Company's proposed short-term interest rate of 1.873 percent, which is double the Company's projected 2015 interest rate included in its initial filing (0.895 percent), and more than triple its actual interest rate in 2015 (0.562 percent). Id. at 36, CMA-RD-5, GP Ex. 2 at Statement D, Schedule D-1, p. 2 (Initial Filing).

Despite the Department's request that the Company provide adequate information that supported its proposed cost of short-term debt, Great Plains did not do so. The Company also provided no calculations supporting its proposed cost of short-term debt, which remains largely unexplained. DOC Ex. 204 at 36 (Addonizio Direct).

Because Great Plains based its test-year cost of short-term debt on the 3-month London Interbank Offered Rate in US dollars (USD LIBOR), the Department calculated the average 3-month USD LIBOR during calendar year 2015, and calculated the spread between that figure and Great Plains' 2015 cost of short-term debt. Id. at 37, CMA-RD-9. The Department then calculated the average 2016 forecasted 3-month USD LIBOR using the January 29, 2016 Bloomberg Forecast provided by the Company, and added the 2015 spread to that figure to derive a more appropriate estimate of Great Plains' 2016 cost of short- term debt. Id. at 37. The Department used the resulting interest rate, 1.205 percent, [FN 4] in addition to fees, which leads to the Department's proposed test year cost of short-term debt for Great Plains of 1.61 percent. Id. at 37, CMA-RD-9.

> *[Footnote 4: Page 37 of Mr. Addonizio's Revised Direct Testimony incorrectly stated that the Department's proposed short-term debt interest rate is 1.244 percent. The correct short-term debt interest rate is 1.205 percent, as noted in Attachment CMA-RD-9 to Mr. Addonizio's Revised Direct Testimony.]*
>
> *The Company accepted the Department's proposed cost of short-term debt.*

XVI. 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	41.712%	5.492%	2.291%
Short-Term Debt	6.556%	1.610%	0.106%
Preferred Stock	1.146%	4.562%	0.052%
Common Equity	50.586%	9.060%	4.583%
Total	100.000%		7.032%

CLASS-COST-OF-SERVICE-STUDY ISSUES

XVII. Class Cost of Service Studies in General

The preceding discussion has sought to quantify the costs that a prudently managed utility serving Great Plains' service area would bear. The next issues will address how Great Plains 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:

- Equity, justice, and reasonableness, and avoidance of discrimination, unreasonable preference, and unreasonable prejudice;[23]
- Continuity with prior rates to avoid rate shock;
- Revenue stability;
- Economic efficiency;
- Encouragement of energy conservation;[24]
- Customers' ability to pay;[25]
- Ease of understanding and administration, and in particular,
- Cost of service.

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[23] Minn. Stat. §§ 216B.01, 216B.03.

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

[25] Minn. Stat. § 216B.16, subd. 15.

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.

To aid this analysis, the Commission directs utilities to conduct a Class Cost-of-Service Study (CCOSS).[26] A class-cost-of-service study allocates a utility's costs among its customer classes in a manner intended to reflect the cost of serving each class. Because there are many ways to make such allocations, the Commission values studies based on clear assumptions that render clear results.

XVIII. Great Plains' Class Cost-of-Service Study

A. Introduction

1. Distinctions

In studying its costs, Great Plains distinguishes between (a) customer classes, (b) firm and interruptible service, (c) residential and general service, (d) sales and transportation service, and (e) customer cost, commodity cost, and capacity cost.

For purposes of its cost study, Great Plains divided its customers into seven classes:

- Residential,
- Small Firm General,
- Large Firm General,
- Small Interruptible Sales,
- Small Interruptible Transportation,
- Large Interruptible Sales, and
- Large Interruptible Transpiration.[27]

Customers in the first three classes receive *firm* service—that is, Great Plains does not expect these customers to curtail their gas consumption even during periods of peak demand for gas. Instead, Great Plains develops its system to deliver as much gas as it anticipates that these customers will demand at any time—and must pass along the resulting cost. Great Plains provides residential service to households, and provides general service to non-household customers (such as commercial or small industrial customers) seeking firm service.

[26] Minn. R. 7825.4300 C.

[27] Great Plains excludes from its CCOSS customers contracting for service under a flexible distribution rate.

Customers in the remaining classes receive interruptible service—that is, they agree to curtail gas consumption under circumstances specified in Great Plains' tariff (for example, during periods of peak demand for natural gas) in exchange for paying lower rates than the firm customers do.

Interruptible *sales* customers purchase their gas directly from the utility. (Customers receiving firm service also acquire gas directly from the utility.) In contrast, interruptible *transportation* customers buy their gas from wholesale providers, and pay Great Plains merely for the service of transporting the gas from the interstate pipeline to the customer.

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 to the customer classes in a different way. For example, because most of Great Plain's customers are residential customers, a choice to characterize a cost as a customer cost will result in most of that cost being borne by residential customers.

Minnesota's gas distribution utilities recover their commodity costs via a rate rider 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 other common facilities—between capacity costs and customer costs.

2. Cost Classification Methods

There are a variety of methods for dividing the costs of the distribution plant between customer costs and capacity costs. Two common methods are the Minimum System method and the Basic Customer method.

The *Minimum System method* estimates the cost a utility would have incurred to build its distribution system at some minimal capacity, and assigns this sum to customer costs. Any additional cost the utility has incurred to build its system is then attributed to the fact that customers demand more than the minimum level of capacity, and so is assigned to capacity 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,"[28] 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.

[28] Gas Distribution Rate Design Manual (1989), published by the National Association of Regulatory Utility Commissioners (NARUC).

The *Basic Customer method* reflects the premise that the distribution system is a shared asset designed and built to provide the capacity to serve customers during periods of peak demand, and thus should generally be regarded as capacity cost. Only costs that can be traced back to a specific customer—such as the costs of service lines, meters, billing, and collection—are classified as customer costs.

B. Positions of the Parties

1. The Company

Unlike its past rate case, Great Plains did not develop separate cost studies for its North and South Districts, but rather developed a single study covering its entire system.

Great Plains designed its CCOSS using the Minimum System method, estimating the cost of building its distribution plant using 2-inch plastic main pipe. This study supported an allocation of 66.74 percent of distribution plant costs to customer cost, and 33.26 percent to capacity costs.

Great Plains later filed updated cost information from a sample of work orders from Great Plains and Montana-Dakota Utilities Co., its sister-subsidiary of MDU. With this new cost data, the study supported an allocation of 75.79 percent of distribution plant costs to customer costs, and 24.21 percent to capacity costs.

However, Great Plains then set aside the results of these analyses and proposed allocating 75 percent of the cost of the distribution plant to *capacity* costs, and only 25 percent to *customer* costs. Great Plains argued that this would result in a more conservative allocation.

In response to criticism of its CCOSS from the Department and the OAG, Great Plains supported two alternative proposals. First, it proposed side-stepping the issue of any shortcomings in its allocation methods by simply assigning all of the distribution plant cost to capacity costs. Second, it also stated that an alternative CCOSS generated by the Department was reasonable; this alternative is discussed below.

2. The Department

While the Department approved of Great Plains' choice of method for allocating distribution plant cost, it nevertheless recommended that the Commission reject the Company's CCOSS, citing three shortcomings in the study.

- Great Plains' choice to build the model based on 2-inch distribution mains was unwarranted, given the prevalence of smaller mains in its system.

- Great Plains failed to support its study with sufficient data about its distribution mains—data regarding the mains' diameter, material, length, vintage, cost when installed, and nominal replacement cost. Even the data provided in the Company's supplemental filings were insufficient to support the study.

- Great Plains then ignored the results of its own study, and proposed a different allocation of distribution plant cost between customer costs and capacity costs. Whatever the merits of Great Plains' proposal for purposes of allocating costs among customer classes, the Department concluded that this proposal was unrelated to the purpose of a CCOSS, which is to identifying class costs.

The Department also remarked on the analytical challenges posed by the fact that Great Plains generated a single cost study to cover both the Company's North and South service areas. However, the Department acknowledged that the Commission authorized Great Plains to file a single, consolidated cost study for purposes of the current rate case.

Using the best information available in the record, the Department fashioned what it called an alternative CCOSS. This study incorporated Great Plains' updated cost data, and then applied the allocator produced by the analysis to generate its conclusions. The Department concluded that even its alternative CCOSS lacked an adequate foundation to provide a reliable guide for allocating costs among customer classes. But the Department reasoned that if the Commission were to conclude that the record evidence is sufficient to support a cost study, then the Department's study would prove more reliable than the Company's study.

Great Plains defended its CCOSS, but also stated that the Department's alternative CCOSS was a reasonable substitute. The OAG disagreed, arguing that the study lacked record support.

Finally, the Department recommended that for Great Plains' next rate case, the Company support its CCOSS using the necessary data regarding the mains' diameter, material, length, vintage, cost when installed, and nominal replacement cost. And if the Company were to file its next rate case before consolidating its North and South service areas, the Department recommended that the Company file separate cost studies for each area.

3. The OAG

The OAG shared the Department's concerns about the shortcomings in Great Plains' CCOSS. In particular, the OAG emphasized that Great Plains' supplemental data did not resolve the problems in the initial study, and introduced new problems regarding the source and adequacy of the new data.

In view of these concerns, the OAG concluded that the record provided insufficient evidence to permit any meaningful class cost analysis. Consequently the OAG recommended rejecting not only the Company's CCOSS, but the Department's alternative CCOSS which was based on the same flawed data.

For Great Plains' next rate case, the OAG recommended that the Company file a CCOSS using the Basic Customer method in addition to any other CCOSS the Company preferred.

C. The Recommendation of the Administrative Law Judge

The ALJ concurred with the Department and the OAG that Great Plains' CCOSS lacked sufficient support, and contained sufficient flaws, to render it unusable as a guide for rate-setting. But the ALJ concluded that the Commission might be able to use the Department's alternative CCOSS, provided that the Commission bears in mind the study's weaknesses.[29]

The ALJ also recommended that the Commission adopt the Department's recommendations about how Great Plains should modify its CCOSS in its next rate case.

In its exceptions to the ALJ's Report, Great Plains acknowledged the shortcomings in the data supporting its CCOSS. But the Company argued that the study's overall conclusion—that large commercial and industrial customers were bearing a disproportionate share of the utility's costs—was still valid, and no refinements in the CCOSS would alter that conclusion. And Great Plains supported the ALJ's finding that the Department's alternative CCOSS could provide useful guidance to the Commission.

In contrast, while the OAG supported the ALJ's conclusion rejecting Great Plains' CCOSS, it opposed the finding that the Department's alternative CCOSS was reliable. The OAG also repeated its proposal that the Commission direct Great Plains, in its next rate case, to file multiple CCOSSs using a variety of analytical methods.

D. Commission Action

The Commission concurs in part in the ALJ's analysis and conclusion except Finding 327 as discussed below.

The Department argued that "the flaws in the Company's methodology are not reasonable and are significant enough to reject the proposed CCOSS…."[30] The ALJ concurred, finding that "Great Plains has filed a CCOSS with insufficient supportive data,"[31] and that the Company then failed to provide an adequate response to the concerns raised by the other parties.[32]

While the Department has proposed an alternative CCOSS, it is based on the same data that Great Plains offered in support of its own CCOSS. The Department proposed that the Commission adopt its alternative CCOSS if and only if it found "the flaws in the Company's methodology not to be significant enough to reject the proposed CCOSS."[33]

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[29] ALJ's Report, at 58.

[30] Ex. 210, at 9 (Ouanes Surrebuttal). *See also* Tr. Evid. Hearing, Vol. 1, at 163:12–19 (Department witness Ouanes describing the updated data provided by Great Plains to bolster its study:"[The Company] provided a new set of data…. From where, I don't know…. [W]e didn't see anything that the Department could verify, basically. So, it's moving on sand at this stage.")

[31] ALJ's Report, at 57.

[32] *Id.* at 58 (noting in particular that the Department "found the [updated data] to be insufficient for a thorough analysis….").

[33] Ex. 210, at 3–4 (Ouanes Surrebuttal).

The ALJ recommended rejection of Great Plains' CCOSS—yet proposed that the Commission could find the Department's alternative to be acceptable. The Commission concludes that this proposition is unsupported in the record. The Commission is persuaded by the Department, the OAG, and the ALJ that the record does not support relying on Great Plains' CCOSS for purposes of estimating the cost of service. And for this reason, the Commission finds that the record does not support relying on the Department's alternative CCOSS either, because it was built on the same foundation.

Consequently the Commission will reject the studies proposed by both Great Plains and the Department. Because the ALJ reached a contrary conclusion in the ALJ's Report at paragraph 327, the Commission will make the following finding instead:

> 327. The Administrative Law Judge concludes that the DOC-DER's alternative CCOSS~~, while imperfect, may be useful to the Commission in proceeding toward the development of rate design~~ should not be adopted in this case given that the DOC-DER's alternative CCOSS relies upon the same flawed data that led the ALJ to recommend rejection of the Company's CCOSS. The Department recommended that the alternative only be used in the event that the Company's CCOSS was found to be reasonable; given that the Company's CCOSS has not been demonstrated as reasonable the alternative must be set aside as well. ~~The Commission and all parties should be aware of the weakness of the alternative CCOSS and weigh it accordingly as a factor in rate design determination.~~

The Commission will not attempt to correct the CCOSS for purposes of the current docket. Instead, the Commission will direct Great Plains to file a new CCOSS in its next docket. This study should also employ the Minimum System method for allocating costs. But to avoid the problems that arose in the current docket, the Commission will direct Great Plains to provide and use non-aggregated distribution mains data (length in feet, original cost of construction and normalized replacement cost) per material, size, and vintage (year).

In addition, the Commission will also direct Great Plains to file in its next rate case an alternative CCOSS using the Basic Customer method. Having both studies will better illuminate how the choice of analytical method influences the costs assigned to each customer class.

Great Plains is also free to file any other CCOSSs it finds appropriate.

Finally, if Great Plains files a new rate case before it has fully consolidated rates for its North and South Districts (discussed below), the Commission directs Great Plains to file each of its CCOSSs for each district individually.

RATE DESIGN ISSUES

XIX. Interclass Revenue Apportionment

A. Introduction

Having resolved questions regarding Great Plains' revenue requirement, the Commission must set rates that will provide a prudently managed utility in Great Plains' circumstances with a reasonable opportunity to recover this revenue requirement. The next step in that process is to determine how much each customer class should be expected to contribute to meeting that revenue requirement.

Great Plains currently recovers from each customer class the following share of its revenue requirement (excluding revenues from the sale of gas itself):

Customer Class	Share of Revenue Requirement
Residential	47.87%
Small Firm General	10.35%
Large Firm General	19.63%
Small Interruptible Sales	12.21%
Small Interruptible Transmission	0.93%
Large Interruptible Sales	4.19%
Large Interruptible Transmission (excluding flexibly priced rates)	4.82%
Total	**100.00%**

B. Positions of the Parties

Great Plains offered detailed proposals for shifting each class's share of total revenues closer to the cost of serving that class—assuming the Commission approved a CCOSS that documented the cost of serving each customer class.

The Department found that Great Plains' proposed interclass revenue apportionment was well-grounded in its CCOSS. Thus, if the Commission were to adopt the Company's CCOSS, the Department would support its proposed revenue allocations. But as discussed above, the Department also recommended that the Commission reject the Company's CCOSS.

If the Commission were to reject all CCOSSs in the record, then both the Department and the OAG recommended that the Commission retain Great Plains' current apportionment. The Department noted that the Commission approved this apportionment in Great Plains' last rate case and thus, in the absence of persuasive contrary information, this allocation remains presumptively reasonable. In practice, this would mean that Great Plains would allocate any rate increase to all customer classes in proportion to each class's share of the Company's current revenues.

C. The Recommendation of the Administrative Law Judge

The ALJ recommended that, if the Commission were to adopt a CCOSS, the Commission rely on that study and set the revenues to be recovered from each class in a manner that is closer to the costs of serving that class.

But if the Commission were to reject all CCOSSs in the record, the ALJ recommended that the Commission adopt the positions advocated by the Department and the OAG.

Great Plains took exception to the ALJ's recommendation, restating its argument that the Commission should shift revenue responsibilities in a manner that more closely resembles the class cost allocations found in the Department's alternative CCOSS.

D. Commission Action

Cost-based rates are among the goals the Commission pursues in designing rates. The Commission takes guidance from the CCOSS because it provides the best evidence in the record for reconciling a concern about cost causation with the goal of permitting a utility an opportunity to recover its costs and earn a fair return.

But in this case, the Commission finds no reliable CCOSS in the record. The Commission previously found Great Plains' existing class revenue apportionment to be reasonable, and nothing in the current docket leads the Commission to reach a contrary conclusion. Consequently the Commission will retain the Company's current class allocation, as recommended by the Department and the OAG. Each class will be expected to contribute its assigned portion of the Company's revenue requirement (excluding the Large Interruptible Transmission Service customers on flexible tariffs).

XX. Monthly Customer Charge and Distribution Charge

A. Introduction

Great Plains 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 (or Basic Customer Charge). 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, Great Plains also assesses a monthly demand charge reflecting the peak amount of gas the customer uses.

To provide a utility with a fair opportunity to recover its revenue requirement from each customer class, the forecasted sum of the customer charge, the distribution charge, and the 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--any increase in the customer charge will have the effect of reducing the volumetric distribution charge, and vice versa.

Below are the recommendations of each party, and the ALJ, regarding the appropriate monthly customer charge:

Customer Class	Current	Great Plains[34]	OAG	Department	ALJ
Residential	$6.50	$9	No change	$8.25	$8.25
Small Firm General	$20	$25	No change	$25	$25
Large Firm General	$25	$50	No change	$40	$40
Small Int. Sales	$125	$200	No change	$175	$175
Large Int. Sales	$200	$250	No change	No change	No change
Small Int. Transport	$175	$200	No change	No change	No change
Large Int. Transport	$250	No change	No change	No change	No change

[34] For some customer classes, Great Plains initially proposed to stop collecting its fixed customer charge on a monthly basis and begin collecting a recalculated charge on a daily basis. But during hearings Great Plains withdrew this proposal.

Any portion of a class's revenue requirement that is not recovered via the fixed customer charge would then be recovered via the distribution charge.

B. Positions of the Parties

Both Great Plains and the Department proposed increasing the monthly customer charge for most customer classes because both the Company's CCOSS and the Department's alternative CCOSS showed that the monthly customer charge was less than the monthly costs for things such as service lines, meters, billing, and collection—charges that do not vary with the amount of gas consumed, or the rate of consumption.[35] If the Commission refrained from increasing customer charges, it would have to increase other charges such as distribution charges. In that case, Great Plains argued, the resulting rate design would impose inappropriate burdens on customers with higher energy consumptions, while relieving other customers of the duty to bear their fair share of their class revenue requirement.

In support of their positions, these parties noted that the Commission had authorized other gas utilities to increase their customer charges on the basis of their CCOSS analyses.

But these parties did not propose to recover all of Great Plains' residential customer costs via the monthly customer charge due to concerns that this would provoke rate shock.[36] Indeed, concern for rate shock prompted the Department to propose smaller increases in the customer charge than Great Plains did. Great Plains defended its proposed rate increases nonetheless, arguing that concerns for rate shock are overstated and that larger shifts are a natural consequence when ratepayers enjoy stable rates for a period of ten years or more.

The OAG opposed any increase in the monthly customer charge, citing three reasons. First, in the absence of an approved CCOSS, the record contains no evidence that Great Plains' customer charges are too low. Second, the Legislature has directed the Commission to set rates in a manner to promote energy conservation "to the maximum reasonable extent."[37] To this end, the OAG recommended keeping the fixed customer charges low and instead increasing the distribution charge, thereby increasing the costs a consumer would bear for each unit of gas consumed. Third, because Great Plains has proposed to implement revenue decoupling, which is designed to levelize a utility's revenues (discussed below), Great Plains does not need the levelized revenues that come from increased monthly customer charges.

C. The Recommendation of the Administrative Law Judge

The ALJ concluded that the Department's recommendation 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. Thus the ALJ recommended that the Commission adopt the Department's recommended monthly customer charges.

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[35] See, for example, Ex. 25 at 12 (Aberle Direct); Ex. 211 at 45 (Heinen Direct).

[36] *Id.* (Aberle Direct).

[37] Minn. Stat. § 216B.03.

D. Commission Action

The Commission is not fully persuaded by the positions advanced by any of the parties or the ALJ.

Whatever the merits of the arguments advanced by Great Plains and the Department for raising the monthly customer charge, these arguments rest upon the premise that the record contains a reliable CCOSS. But as the OAG noted, the record does not. Because the Commission does not accept the premise of their arguments, it cannot accept the conclusion.

By the same token, the Commission is not persuaded by the OAG's arguments for leaving the customer charges unchanged. The Commission acknowledges that the Legislature directs the Commission to design rates to promote conservation to the maximum reasonable extent. But the Commission concurs with Great Plains and the Department that a choice to recover the full amount of the revenue increase from only the distribution charge, with no additional contribution coming from the customer charge, would unreasonably burden customers with relatively high consumption.

The Commission previously found that Great Plains has demonstrated the need to increase its revenue requirement, and divided this new revenue responsibility among customer classes in proportion to each classes' current contribution to Great Plain's revenues. Great Plains must now increase rates for each of these customer classes—and the Commission is not persuaded that customer charges should be exempt from that increase.

Consequently, the Commission will authorize an increase in each class's monthly customer charge and in its distribution charge in proportion to the increase in Great Plains' overall revenue requirement.

XXI. Flexible Rates

A. Introduction

Generally Great Plains cannot alter the rates established by the Commission for sales or transportation service except by filing a rate case.[38] But the Legislature grants to natural gas distribution utilities the flexibility to charge a different rate to a larger interruptible sales and transportation customer if the utility's service to that customer is "subject to effective competition."[39] Generally, a utility's service to a customer is subject to effective competition if the customer has an alternative source of energy—including having a viable option to connect directly to an interstate gas pipeline and bypass the utility's distribution system.[40]

Great Plains has negotiated flexible rates with various large customers. In filing its rate case, Great Plains does not project the same amount of revenues from these customers as it would for a similar customer that did not receive the benefit of flexible rates.

[38] Minn. Stat. § 216B.16, subd. 7.

[39] Minn. Stat. § 216B.163, subd. 1(b).

[40] Minn. Stat. § 216B.163, subd. 4.

B. Positions of the Parties

The Department questioned Great Plains' choice to establish separate rates for two large customers—one existing customer, one new. To respect the privacy of these customers, the parties referred to them as A and B, respectively. The Department recommended that the Commission impute to Great Plains the revenues that these customers would have generated if they had been buying service from the Company according to standard tariffed rates.

Great Plains defended its choice to offer flexible rates to these customers.

Customer A has received service on a flexible tariff since Great Plains' last rate case in 2004. The Company argued that the customer's proximity to an interstate pipeline means that the customer could bypass Great Plains' system if the utility refused to offer service at a discount. However, given the Company's proposal to consolidate its North and South districts and average the distribution charges, Great Plains acknowledges that Customer A's flexible rates could end up being higher than its generally available tariffed rates.

Customer B is a new customer that, according to Great Plains, consumes 20 percent of the gas that flows on its system. This customer could credibly buy coal and fuel oil instead of buying natural gas shipped via the utility's transportation services, Great Plains claimed. Great Plains argued that the customer had already paid more to receive the utility's services than comparable customers, in that the customer incurred its own expenses (Contribution in Aid of Construction) to connect to the utility's system.

More generally, Great Plains argued that ratepayers benefit from having these customers on the Company's system and bearing at least part of Great Plains' fixed costs, instead of obtaining energy elsewhere and leaving all these costs to be borne by the Company's other ratepayers. And Great Plains argued that it has every incentive to maximize its revenues from these customers, so the Commission should trust the Company's business judgment on this matter.

C. The Recommendation of the Administrative Law Judge

The ALJ concurred with the Department that Great Plains had failed to demonstrate that the Company's service to these two customers is truly subject to effective competition. Consequently the ALJ supported the Department's proposed adjustment to the Company's revenues, which would have the effect of reducing the size of the utility's rate increase.

D. Commission Action

In an abundance of caution, the Commission will allow Customers A and B to continue receiving service according to flexible rates and will deny the Department's proposal to impute revenues to the Company on this basis. Thus, the Commission will decline to adopt the ALJ's recommendations on this matter.

Great Plains has not provided all the evidence and analysis the Commission might anticipate in support of the Company's choice to extend flexible rates to these customers. Nevertheless, Great Plains provided sufficient evidence regarding the customers' potential to obtain energy from other sources to justify a finding in support of the Company's strategy in this matter.

But in Great Plains' next rate case, the Commission will direct the Company to provide proper studies and analyses that fully support Great Plains' statements that these customers subject the Company to effective competition by having a means to by-pass the utility's system or otherwise secure an alternative source of energy.

XXII. Revenue Decoupling Pilot Program

A. Introduction

The cost a natural gas distribution utility incurs to build and maintain its distribution system does not vary month to month based on the amount of gas consumed by its customers. Yet the amount Great Plains charges customers in any month for the use of this plant reflects both a fixed component (such as the monthly customer charge) and a variable component (the distribution charge that increases as the amount of gas consumed increases). The Commission sets this distribution charge based on a forecast of the utility's energy sales. But when the utility sells more energy than forecast, ratepayers pay higher bills than expected and the utility over-collects; conversely, when a utility sells less energy than forecast, ratepayers pay lower bills than expected and the utility under-collects.

This rate design has two adverse consequences. First, both the utility and ratepayers 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 a loss of 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,"[41] and has authorized some three-year pilot programs implementing decoupling.[42]

B. Positions of the Parties

1. Great Plains

Great Plains proposed a three-year pilot program implementing revenue decoupling. Generally the formula would work as follows. The Commission has approved an interclass revenue apportionment for non-gas costs. At the end of each year, Great Plains would calculate the non-gas revenues generated by the class, and compare them to the class's revenue requirement. For each class, the Company would then adjust future delivery charges to return any surplus to, or recover any deficit from, members of the same class.[43]

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[41] 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).

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

[43] Ex. 25, at 26-27 (Aberle Direct).

After receiving recommendations from the Department, Great Plains offered a modified proposal that included the following components:

First, Great Plains would implement a *full decoupling mechanism*, meaning that the mechanism would calculate adjustments when the Company's energy sales differ from forecast, regardless of the reason for the difference.

Second, the new rate design would apply to all customers except the following:

- Flexible rate customers. By statute, a utility may not charge a customer receiving service on the basis of flexible rates less than its incremental cost; a decoupling adjustment might cause the rate to dip below that level.

- One Large Interruptible Transportation customer that has received Commission approval to be exempt from the state's Conservation Improvement Program (CIP).

Third, Great Plains would provide an evaluation report to the Commission each year of the pilot program.

Finally, Great Plains proposed no cap on the amount of the rebate or surcharge used to implement the decoupling mechanism, on the theory that any adjustment would be small relative to the size of a customer's total bill. If the Commission were to decide to establish a limit on the size of any surcharge, the Company would propose setting a 10 percent cap on both the size of any surcharge and the size of any rebate.

2. The Department

The Department generally supported Great Plains' proposal but with modifications. The sole unresolved issue involved the implementation of a cap on rate surcharges but not refunds.

The Department recommended limiting the size of any surcharge to 10 percent of non-gas margin revenues (excluding revenues for the Conservation Cost Recovery Charge). This cap would foreclose the possibility that a surcharge would provoke rate shock. Moreover, the Department reasoned that Great Plains is in a better position to respond to the consequences of an adverse unanticipated rate adjustment than are ratepayers.[44] Finally, the Department noted that the Commission had authorized caps on decoupling surcharges, but not on decoupling refunds, in other cases.

Great Plains opposed the Department's proposed cap on surcharges but not refunds, arguing that creating this kind of regulatory asymmetry was unfair.

C. The Recommendation of the Administrative Law Judge

The ALJ found the Department's analysis persuasive. Thus the ALJ recommended that the Commission approve Great Plains' revenue decoupling pilot program with the changes proposed by the Department—including the proposal to establish a cap on surcharges but not refunds.[45]

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[44] Ex. 213 at 38-40 (Heinen Surrebuttal).

[45] ALJ's Report, Findings 509, 510.

D. Commission Action

1. Cap

The Commission concurs in the ALJ's analysis and conclusion. Great Plains' proposed revenue decoupling pilot program, with the Department's proposed revisions, is well designed to eliminate the utility's disincentive to promote conservation and energy efficiency, without exposing ratepayers to needless regulatory risk.

The Legislature authorized the Commission to approve revenue decoupling mechanisms provided they would not adversely affect ratepayers.[46] In implementing this policy, the Commission has always directed utilities to implement caps on surcharges.[47] Otherwise, ratepayers would bear the full risk that arises from decoupling when a utility's sales fall below forecast.

While Great Plains does not oppose adopting a cap, it argues in favor of a symmetrical cap on surcharges and refunds. While a symmetrical cap might appear equitable, the utility and ratepayers are not in a comparable position to adapt and respond to changes; in particular, the utility can petition for rate relief, while ratepayers have no such remedy. It is instructive that the Legislature directs the Commission to design a decoupling mechanisms specifically to avoid adversely affecting ratepayers.

2. Methods for Calculating Adjustments

The Commission notes that Great Plains proposes to calculate its decoupling adjustment using either of two methods—per customer or per customer class—and to use the method that maximizes the Company's retained earnings. While neither method is inherently incorrect, and both can measure net gains and losses, the operation and financial impact of these methods warrant exploration. Experience with both methods may bring to light equitable or policy considerations that are not immediately apparent.

The Commission will therefore require Great Plains to calculate its annual decoupling adjustment using both methods and to report the results in its annual and final reports on its pilot decoupling program. In the meantime, the Company will be permitted to use either method.

Finally, the Commission observes that revenue decoupling was created to facilitate a utility's promotion of energy conservation and efficiency. Yet full decoupling permits a utility to make adjustments to compensate for reduced energy sales that occur for any reason whatsoever,

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[46] Minn. Stat. § 216B.2412, subds. 2, 3.

[47] *See* Ex. 211 at 74-75 (Heinen Direct), citing *In the Matter of the Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-08-1075, Findings of Fact, Conclusions of Law, and Order at 23 (January 11, 2010) (partial decoupling pilot program; asymmetrical cap with no limit on refunds to ratepayers but 3 percent utility limit on surcharges*); 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 13-14 (July 13, 2012) (full decoupling pilot with symmetrical 10 percent cap on refunds and surcharges); and *In the Matter of the Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-13-316, Findings of Fact, Conclusions, and Order at 46-48 (June 9, 2014) (full decoupling pilot with an asymmetric cap limiting utility surcharges to 10 percent (no stated limit on refunds)).

including abnormal weather. While these adjustments are not inconsistent with the goal of promoting conservation and efficiency, they are unrelated to those purposes.

In Great Plains next rate case, therefore, the Commission may explore the option of barring the Company from implementing decoupling adjustments unless the Company can demonstrate that it has achieved a minimum level of energy savings. To this end, the Commission will ask the Department to propose an appropriate minimum level of energy savings to use in this test.

XXIII. First-Through-The-Meter Service for Interruptible Customers

A. Introduction

In contrast to customers who subscribe for firm service, customers who subscribe for interruptible service pay lower rates, but must be prepared to discontinue taking gas under circumstances set forth in the tariff—typically, circumstances of peak demand for gas. This arrangement provides the advantage of cheaper rates, but the disadvantage of the possibility of having service interrupted.

Great Plains now proposes to offer a hybrid service that would mitigate some of the disadvantage of interruptible service.

B. Positions of the Parties

Great Plains proposes to offer its First-Through-The-Meter service. A subscriber for this service would be entitled to receive a specified amount of gas each month as firm service, free from the risk of interruption (except under emergency circumstances as might affect the service of any customer). But consumption of gas beyond the specified level would be treated as interruptible service. In the absence of this kind of service, a customer seeking to emulate this option would have to bear the cost and burden of installing two gas service lines and have two meters, one for firm service and one for interruptible.

The Department found Great Plains' proposal to be reasonable, provided the Company actually has sufficient capacity to provide the level of firm service required. However, the Department noted that Great Plains had not imputed any additional revenues arising from the proposal to sell additional firm service. Consequently the Department imputed the additional revenues it estimated the utility would earn from interruptible customers that may subscribe for the new service. The Department also proposed additional tariff language to guard against the possibility that Great Plains might over-subscribe its firm service.

Great Plains accepted the tariff language, but rejected the Department's imputation of revenues. Great Plains conjectured that customers currently taking interruptible service would be unlikely to switch to the new service, so that the new service would merely serve new customers.

C. The Recommendation of the Administrative Law Judge

The ALJ shared the Department's conclusion that the proposed First-Through-The-Meter services, with the revised tariff language, was reasonable—and that Great Plains should have to recognize additional revenues arising from its new service.

D. Commission Action

The Commission concurs in the ALJ's analysis and conclusion. The new service may well fill a niche for customers that can bear some risk of service interruption, but still require some minimum level of stable gas supply. When an interruptible customer decides to subscribe to firm service for part or all of its load, that customer would pay the same cost of gas factors as any other firm customer. But if Great Plains is going to offer a new service prospectively, it makes sense for the Commission to take the forecasted revenues into account in the context of the current rate case.

XXIV. Base Cost of Gas

A utility's base cost of gas for any given customer class refers to the average cost per unit of gas purchased over a 12-month period for that customer class.[48]

On July 8, 2016, Great Plains made an informational filing disclosing that its commodity cost of gas had declined since the start of this rate case. During the Commission's hearings, no party objected to having Great Plains update the calculation of its base cost of gas to incorporate the most recent information in the record—information about Great Plains' sales forecasts, gas costs, and the Commission's decisions on other topics.

Accordingly, the Commission will direct Great Plains to update its base cost of gas rates to reflect—

- The updated sales forecasts,

- the reduction in the commodity cost of gas as provided by Great Plains in its July 8, 2016 informational filing, and

- all Commission decisions.

XXV. Consolidation of North and South PGA Districts (Distribution)

A. Introduction

Great Plains currently provides service in two districts, North and South, at different rates. Today Great Plains serves both districts using the same staff, offices, equipment, and capital, and using gas procured from the same source at the same supply point. All parties now agree that Great Plains should adopt a uniform set for tariffs to apply throughout its service areas.

Great Plains had already started this consolidation process in its last rate case by implementing the same monthly customer charges in both districts. To further the consolidation process, all parties agreed that Great Plains should consolidate the base cost of gas factors in its purchased gas adjustment (PGA) by July 1, 2017. But given the magnitude of the difference in the distribution charges assessed in the North and South Districts, parties disagreed about how quickly to consolidate these charges.

[48] Minn. R. 7825.2400, subp. 4a and 5; and 7825.2700, subp. 2.

B. Positions of the Parties

Great Plains proposed consolidating the distribution charges over a two-year period, in three phases. In the first phase, Great Plains would implement the rate increases resulting from the increased revenue requirement demonstrated in this docket. One year later, the Company would implement the second phase and adopt half of the change in the distribution charge arising from the consolidation, increasing the charge in the South District and reducing it in the North. The following year the Company would implement the final phase, adopting a uniform distribution charge for each customer class.[49]

Both the Department and the OAG expressed concern that the process of consolidating the distribution charge would cause rate shock to customers in the South District. The Department supported Great Plains' three phases but proposed implementing them over three years, as Great Plains had implemented similar rate changes in the past.

C. The Recommendation of the Administrative Law Judge

The ALJ found that the parties' proposal to consolidate Great Plains' base cost of gas PGA rates by July 1, 2017, was reasonable and supported in the record.

The ALJ also found that the record supported consolidation of the distribution charge. But the ALJ did not support extending implementation over a three-year period, finding that it would be reasonable to phase in the rate change over a period of two years. The ALJ reasoned that the current era of low commodity costs would offset any risk of rate shock, and that the magnitude of the rate changes triggered by the consolidation were not sufficient to justify the additional delay.

D. Commission Action

The Commission concurs in the ALJ's analysis and conclusion.

Great Plains' two-year schedule for implementing the consolidation of the distribution charges is reasonable and gradual. For example, at the end of this rate case customers will experience a rate increase resulting from the Company's increased revenue requirements. A year later, the average residential customer in the South District would experience an additional increase in his or her monthly bill of $0.76, representing the first half of the consequences of consolidating the distribution charges. And the following year the average residential customer would experience a final increase in the monthly bill of $0.77.[50] As this is occurring, customers in the North District would be seeing corresponding decreases in their distribution charge.

The parties do not dispute the magnitude of these adjustments; the sole dispute concerns the pace for implementing them.

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[49] Ex. 26 at 15-16 (Alberle Rebuttal).

[50] *Id.* at 15-18, TAA-7 at 27 (Aberle Rebuttal).

The Commission finds that the magnitude of the increases in the distribution charge do not justify delaying the benefits of consolidating the distribution rates and providing customers throughout Great Plains' system with uniform rates. As the Company observes, the current period of low gas costs favors implementing these changes sooner rather than later, while these benefits may help offset the added burdens.

XXVI. Elimination of Standby Service Tariff

A. Introduction

A natural gas distribution utility must design and build its system to have the capacity to deliver sufficient gas to meet the demands of its firm customers even on the coldest days when demand is highest. The cost for all this capacity does not vary with the amount of gas consumed. But utilities recover these costs based, in part, on the amount of gas they sell.

Some customers rely on alternative sources of energy as their primary source, and take Great Plains' service only as a back-up when their primary source is depleted or fails, or when the customer's demand for energy exceeds what the primary source can provide on its own. These customers tend to demand the utility's services during periods of peak demand, but not otherwise. That is, these customers add to the demand that drives a utility's capacity costs, but they contribute less revenue than do customers who buy gas from the Company on a more regular basis.

To address this situation, Great Plains implemented its Standby Service tariff. The tariff is intended to help the Company recover an appropriate share of its fixed costs from customers that use Great Plains service merely as a back-up source of energy.

In the current rate case, Great Plains proposed to eliminate this tariff.

B. Positions of the Parties

Great Plains argued that the Standby Service tariff has proven difficult to administer. Standby customers do not always identify themselves and volunteer to pay this additional charge. As a result, Great Plains must seek to identify standby customers based on each customer's consumption patterns, which is an unavoidably subjective determination.

The Department opposed Great Plains' proposal. The Department argued that Great Plains did not document the extent of the burden imposed by implementing the Standby Service tariff. Moreover, the Department noted that elimination of the tariff would result in all firm ratepayers, not just standby customers, bearing the costs that had previously been borne by the tariff.

C. The Recommendation of the Administrative Law Judge

Having reviewed the arguments of the parties, the ALJ concurred with the Department that Great Plains had failed to adequately support its request to eliminate this tariff. Therefore the ALJ recommended rejecting Great Plain's proposal.

D. Commission Action

The Commission values uniform application of utility tariffs, and thus is concerned when it learns that a utility feels that it cannot implement a tariff in a reasonably even-handed and objective manner. For this reason, the Commission is persuaded to grant Great Plains' request to discontinue its Standby Service tariff. As a result, the Commission will decline to adopt the ALJ's recommendation.

FINANCIAL SCHEDULES AND COMPLIANCE

XXVII. Overall Financial Schedules

A. Gross Revenue Deficiency

The above Commission findings and conclusions result in a Minnesota jurisdictional total gross revenue deficiency of $1,141,376, as shown below:

Revenue Requirement Summary
Test Year Ending December 31, 2016

Description		
Average Rate Base	$	16,824,465
Rate of Return		7.032%
Required Operating Income	$	1,183,096
Operating Income	$	513,907
Income Deficiency	$	669,189
Gross Revenue Conversion Factor		1.705611
Gross Revenue Deficiency	$	1,141,376

B. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the test year is $16,824,465, as shown below:

Rate Base Summary
Test Year Ending December 31, 2016

Description		
PLANT IN SERVICE		
Intangible	$	2,657,383
Transmission	$	2,357,471
Distribution	$	31,650,648
General	$	6,998,279
Common	$	1,103,383
Common – Intangible	$	684,417
Total Plant In Service	$	45,451,581
RESERVE FOR DEPRECIATION		
Intangible	$	721,732
Transmission	$	1,308,367
Distribution	$	20,806,428
General	$	2,459,972
Common	$	444,783
Common - Intangible	$	322,555
Total Reserve For Depreciation	$	26,063,837
NET PLANT IN SERVICE		
Intangible	$	1,935,651
Transmission	$	1,049,104
Distribution	$	10,844,220
General	$	4,538,307
Common	$	658,600
Common - Intangible	$	361,862
Total Net Plant In Service	$	19,387,744
Additions:		
Materials and Supplies	$	431,754
Gas in Underground Storage	$	337,632[51]
Prepayments	$	72,217
Unamortized Loss on Debt	$	69,520
Total Additions	$	911,123

[51] Gas in Underground Storage decreased by $12,334 from Great Plains' initially proposed amount of $349,966 due to the requirement that Great Plains update its base cost of gas rates and its Gas in Underground Storage balance.

Deductions:		
Accumulated Deferred Income Taxes	$	2,813,252
Customer Advances	$	661,150
Total Deductions	$	3,474,402
TOTAL AVERAGE RATE BASE	$	16,824,465[52]

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 $513,907, as shown below:

Operating Income Summary
Test Year Ending December 31, 2016

Description		
OPERATING REVENUES		
Sales	$	20,684,195
Transportation	$	1,310,252
Other Operating Revenue	$	366,449
Total Operating Revenues	$	22,360,896
OPERATING EXPENSES		
Operation and Maintenance		
Cost of Gas	$	13,247,538
Other O&M :		
Other Gas Supply	$	61,697
Transmission	$	20,833
Distribution	$	2,369,790
Customer Accounts	$	1,041,159
Customer Service & Information	$	452,249
Sales	$	54,708
Administrative & General	$	1,937,989
Total O&M	$	19,185,963
Depreciation	$	1,729,126
Taxes Other than Income Taxes	$	853,840
Income Taxes	$	78,060
Total Expenses	$	21,846,989
Operating Income	$	513,907

[52] Total Average Rate Base reflects the update (reduction) in Gas in Underground Storage balance.

XVIII. 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. Great Plains Natural Gas Company is entitled to increase Minnesota-jurisdictional revenues by $1,141,376 to produce jurisdictional total gross revenue of $23,502,272 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 test year rate base shall be $16,836,799 as proposed by Great Plains.[53]

4. The test year depreciation expense shall be $1,729,126 as proposed by Great Plains.

5. In lieu of ALJ Finding 119 the Commission adopts the following:

> As for the remaining O&M expenses included in the test year, but which are not further broken down by the parties, the 2015 Update should only be used as a check on the reasonableness of the projected 2015 information contained in the Great Plains' initial Petition. The Commission finds that the small variance between projected 2015 expenses and the 2015 Update is minor and demonstrates the reasonableness of the Company's initial projections.

6. In lieu of ALJ Finding 177 the Commission adopts the following:

> The 2015 Update was based on the actual average rate base from January to October 2015 – but estimates for November and December 2015. The Commission finds that the 2015 Update should only be used as a check on the reasonableness of the projected 2015 information contained in the initial Petition. A possible (not actual) 1.6% difference in projected 2015 rate base does not warrant an adjustment, but rather validates Great Plains' original projection in light of Great Plains' near-term planned investment in rate base.

7. Great Plains shall set its test year pension expense at the five-year (2010–2014) average of $7,401.

[53] This amount of rate base is before the required update to Gas in Underground Storage.

8. Great Plains shall use a four-year amortization period for its rate case expenses, and shall track any over-recovery of rate case expenses for credit to the revenue requirement in its next rate case.

9. ALJ Report 201 footnote 164 is adopted with the following modification:

> 164, n.210. Id. at 28. <u>Findings of Fact, Conclusions, and Order, *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-15-424, at 28 (June 3, 2016).</u>

10. 100 percent, or $9,072, of AGA membership dues shall be excluded from test year expenses.

11. 100 percent, or $522, of Minnesota Chamber of Commerce membership dues shall be excluded from test year expenses.

12. Interest synchronization adjustment shall be calculated using the Commission approved rate base and weighted cost of the combined long-term and short-term debt.

13. Thirty days from the date of this order, or 30 days after the relevant operating year's tax return, whichever is the earliest practicable date, Great Plains shall make compliance filing(s) stating whether or not the Company has elected to take federal bonus depreciation in 2015 and/or in 2016.

14. For clarity, the Commission adopts Finding 546, as set forth below:

> <u>546. The OAG recommended, and Great Plains agreed, that the Commission require Great Plains to include detail from the most recently completed fiscal year in addition to a summary for each expense category of test year amounts, to provide information on the top-10 overall compensated employees and directors showing the allocated amounts to the Minnesota jurisdiction as well as the top-10 compensation and expenses for those individuals with the highest allocated cost to the Minnesota jurisdiction, and to provide a summary page showing the total amount from each detailed schedule for the last completed fiscal year and for the test year.</u>

15. The Commission adopts paragraph 270, but corrects the reference to $322,306 to $3<u>3</u>2,306.

16. The Commission adopts ALJ paragraph 544 with the following modifications requiring Great Plains to improve its forecast methodology in future rate filings by providing the following information, to the extent practicable, or explaining why the information is not available:

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

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

c. 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;

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

e. if, in the future, Great Plains 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;

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

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

17. In future rate cases, if Great Plains has any Loss on Debt Repurchased, it must clearly identify the Debt Repurchased in its initial filing, explain the relationship of the Debt to Great Plains (for example, why Great Plains and Minnesota ratepayers are being allocated a portion of the loss) and explain the amortization of the loss if it is not in equal, annual amounts.

18. The Commission adopts the following supplemental findings, proposed by the Department, on the cost of debt:

Supplemental Findings on the Cost of Long-Term Debt

In its initial filing, Great Plains proposed a cost of long-term debt of 5.777 percent that reflected a projected issuance of a $150 million note with a 30-year term and a 5 percent interest rate. DOC Ex. 204 at 38 (Addonizio Direct). In its response to DOC Information Request No. 210, Great Plains explained that it issued three notes during 2015 totaling $150 million, with terms of 10 years, 15 years, and 30 years, and interest rates of 3.78 percent, 4.03 percent, and 4.87 percent, respectively. DOC Ex. 204 at 38, CMA-RD-10 (Addonizio Direct).

Because those interest rates are lower than the projected rate of 5.00 percent, Great Plains cost of long-term debt fell to 5.492 percent in the updated Statement D provided in response to DOC Information Request No. 209. Id. at CMA-RD-5. The Department reviewed Great Plains calculations of its proposed cost of long-term debt and concluded that the calculations are reasonable. Id. at 38.

Supplemental Findings on the Cost of Short-Term Debt

Unlike Great Plains' proposed long-term debt, the Department concluded that Great Plains had not demonstrated that its proposed short-term cost of debt is reasonable (i.e. not unreasonably high). DOC Ex. 204 at 37 (Addonizio Direct).

As shown in its initial filing, Great Plains assumed an interest rate of 1.873 percent on its short-term debt during test-year 2016. GP Ex. 2 at Statement D, Schedule D-1, p. 2 (Initial Filing). Great Plains also included in its cost of short-term debt the expense associated with the amortization of fees associated with its revolving credit facility. Id.; DOC Ex. 204 at 36 (Addonizio Direct). Adding these amortization fees raised the cost of short-term debt from 1.873 percent to 2.274 percent. DOC Ex. 204 at 36 (Addonizio Direct).

The Department agreed that it is reasonable for Great Plains to include an expense component for fees in the calculation of its cost of short- term debt. Id. The Department did not agree, however, with the Company's proposed short-term interest rate of 1.873 percent, which is double the Company's projected 2015 interest rate included in its initial filing (0.895 percent), and more than triple its actual interest rate in 2015 (0.562 percent). Id. at 36, CMA-RD-5, GP Ex. 2 at Statement D, Schedule D-1, p. 2 (Initial Filing).

Despite the Department's request that the Company provide adequate information that supported its proposed cost of short-term debt, Great Plains did not do so. The Company also provided no calculations supporting its proposed cost of short-term debt, which remains largely unexplained. DOC Ex. 204 at 36 (Addonizio Direct).

Because Great Plains based its test-year cost of short-term debt on the 3-month London Interbank Offered Rate in US dollars (USD LIBOR), the Department calculated the average 3-month USD LIBOR during calendar year 2015, and calculated the spread between that figure and Great Plains' 2015 cost of short-term debt. Id. at 37, CMA-RD-9. The Department then calculated the average 2016 forecasted 3-month USD LIBOR using the January 29, 2016 Bloomberg Forecast provided by the Company, and added the 2015 spread to that figure to derive a more appropriate estimate of Great Plains' 2016 cost of short- term debt. Id. at 37. The Department *used the resulting interest rate, 1.205 percent, [FN 4] in addition to fees, which leads to the Department's proposed test year cost of short-term debt for Great Plains of 1.61 percent. Id. at 37, CMA-RD-9.*

[Footnote 4: Page 37 of Mr. Addonizio's Revised Direct Testimony incorrectly stated that the Department's proposed short-term debt interest rate is 1.244 percent. The correct short-term debt interest rate is 1.205 percent, as noted in Attachment CMA-RD-9 to Mr. Addonizio's Revised Direct Testimony.]

The Company accepted the Department's proposed cost of short-term debt.

19. The Commission modifies ALJ Finding ¶ 2 to read as follows:

> Great Plains is ~~owned by Great Plains~~ <u>a Division of</u> MDU Resources Group Inc. (MDU). MDU, located in Bismarck, North Dakota, is a publicly traded company with a diverse range of nationwide subsidiaries, including electric and natural gas utilities as well as construction companies. Total revenues for MDU in 2014 were $4.7 billion.

20. The Commission modifies ALJ Finding ¶ 3 to read as follows:

> Great Plains shares personnel and facilities with Montana-Dakota Utilities Co., another ~~subsidiary~~ <u>Division</u> of MDU. Montana-Dakota Utilities Co. provides regulated gas and electric service in Montana, North Dakota, South Dakota, and Wyoming.

21. The Commission modifies ALJ Finding ¶ 55 to read as follows:

> In its 2015 Update, filed on January 4, 2016, Great Plains <u>provided updated 2015 Rate Base and Operating Statement financial information based on the actual 2015 data through October 31, 2015 and revised projected data for the balance of 2015 (updated 2015). Great Plains also provided bridge schedules from the updated 2015 to the most recent fiscal year 2014 and the 2016 test year as originally filed.</u> ~~used a forecasted test year representing the 12 months ending December 31, 2016. Development of the 2016 test year began with 2014 calendar year actual results and then included adjustments and projections for 2015 and 2016 to produce its test year costs.~~

22. Regarding the Class Cost of Service Study (CCOSS):

    A. The Commission rejects Great Plains' CCOSS and the Department's alternative CCOSS.

    B. The Commission modifies ALJ Finding ¶ 327 to read as follows:

327. The Administrative Law Judge concludes that the DOC-DER's alternative CCOSS~~, while imperfect, may be useful to the Commission in proceeding toward the development of rate design~~ should not be adopted in this case given that the DOC-DER's alternative CCOSS relies upon the same flawed data that led the ALJ to recommend rejection of the Company's CCOSS. The Department recommended that the alternative only be used in the event that the Company's CCOSS was found to be reasonable; given that the Company's CCOSS has not been demonstrated as reasonable the alternative must be set aside as well. ~~The Commission and all parties should be aware of the weakness of the alternative CCOSS and weigh it accordingly as a factor in rate design determination.~~

C. In its next general rate case, Great Plains shall do the following:

- File a Basic Customer method CCOSS as well as a Minimum System method CCOSS supported by distribution mains data (length in feet, original cost of construction, and normalized replacement cost) disaggregated into material, size, and vintage (year).

- Submit separate CCOSSs for the North and South Districts if the rate areas have not been consolidated.

23. Regarding the class revenue apportionment, Great Plains may increase the revenues it recovers from each customer class listed below by a percentage equal to the percentage increase in revenues authorized by the Commission, such that each listed class would be expected to contribute its assigned portion of the Company's revenue requirement (excluding revenues from Large Interruptible Transmission Service customers on flexible rates):

Customer Class	**Share of Revenue Requirement**
Residential	47.87%
Small Firm General	10.35%
Large Firm General	19.63%
Small Interruptible Sales	12.21%
Small Interruptible Transmission	0.93%
Large Interruptible Sales	4.19%
Large Interruptible Transmission (excluding flexibly priced rates)	4.82%
Total	**100.00%**

24. Regarding the monthly customer charge and the volumetric distribution charge:

A. The Commission rejects the rate design recommended in the ALJ's Report.

B. For each of the customer classes listed above, Great Plains shall raise its monthly customer charge (Basic Customer Charge) and its volumetric distribution charge by the percentage that the Commission authorizes Great Plains to increase its revenue requirement.

25. Regarding customers receiving service via flexible rates:

A. Great Plains may continue to serve Customers A and B according to their flexible rate schedules.

B. In its next rate case Great Plains shall file proper studies and analyses that fully support Great Plains' statements in this docket that these customers could plausibly seek gas service directly from an interstate pipeline, or have economic alternative fuels available to them.

26. Regarding Great Plains' Revenue Decoupling Pilot Program:

A. The Commission approves Great Plains' proposed revenue decoupling pilot project as modified herein.

B. In the annual reports and the final project report that Great Plains will file as part of its pilot program, Great Plains shall provide calculations of its decoupling adjustments derived using the per-customer method and the per-customer-class method.

C. The Commission asks the Department, in Great Plains' next rate case, to propose an appropriate minimum level of energy savings that the utility should achieve before Great Plains could qualify to implement a revenue decoupling surcharge.

27. Great Plains shall implement its proposed First-Through-The-Meter service with the tariff language proposed by the Department, and shall impute the revenues estimated to arise from this service.

28. Great Plains shall update its base cost of gas rates to reflect—

A. the updated sales forecasts),

B. the reduction in gas costs as provided by Great Plains in its July 8, 2016 informational filing, and

C. all Commission decisions.

29. Regarding the consolidation of the rates in the North and South Districts:

    A. Great Plains shall implement a consolidated base cost of gas and purchased gas adjustment (PGA) beginning July 1, 2017.

    B. Great Plains shall consolidate its distribution rates according to its three-phase process implemented during the two years following implementation of the general rate increase resulting from this proceeding.

30. Great Plains shall eliminate its Standby Service tariff.

31. 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. The approved 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 CCRC based upon the decisions made herein for inclusion in the final Order. 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.

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.

32. 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.