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April 10, 2020

The Honorable Ann C. O'Reilly
Administrative Law Judge
Office of Administrative Hearings
PO Box 64620
St. Paul, MN 55164-0620

Re: ***In the Matter of the Petition by Great Plains Natural Gas Company, a Division of Montana-Dakota Utilities, Co., for Authority to Increase Natural Gas Rates in Minnesota***
OAH Docket No. 65-2500-36528; MPUC Docket No. G004/GR-19-511

Dear Judge O'Reilly:

Enclosed and filed herewith, find please find the Initial Post-Hearing Brief of the Minnesota Department of Commerce, Division of Energy Resources.

Sincerely,

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Enclosure

OAH Docket No. 65-2500-36528

BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
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Katie Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph Sullivan	Commissioner
John Tuma	Commissioner

In the Matter of the Petition by Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities Co., for Authority to Increase Natural Gas Rates in Minnesota	MPUC Docket No. G-004/GR-19-511 OAH Docket No. 65-2500-36528

INITIAL POST HEARING BRIEF OF THE MINNESOTA DEPARTMENT OF COMMERCE, DIVISION OF ENERGY RESOURCES

April 10, 2020

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I. INTRODUCTION

The Minnesota Department of Commerce, Division of Energy Resources (Department or DER) respectfully submits this Post-Hearing Initial Brief (DER Initial Brief) to provide the Administrative Law Judge (ALJ) and the Minnesota Public Utilities Commission (Commission) with factual and legal analysis pertaining to the petition by Great Plains Natural Gas Co., a Division of Montana Dakota Utilities Co., (Great Plains, GP or Company) for authority to increase natural gas rates in Minnesota. As discussed in detail below, the Department recommended recovery of a net revenue deficiency for the 2020 test year of $2,486,378. This is a reduction of $363,308 from Great Plains' proposal of $2,849,686. It allows Great Plains 87 percent of Great Plains' proposed recovery.[1] It assumes an overall rate of return of 6.786 percent, as recommended by the testimony of Department witness Mr. Craig Addonizio.[2]

II. PROCEDURAL HISTORY

Appended hereto as Appendix A is a procedural history of this matter.

III. STATEMENT OF THE ISSUES

The NOTICE OF AND ORDER FOR HEARING identified the following issues to be addressed:

- Whether the test year revenue increase sought is reasonable or will result in unreasonable and excessive earnings;
- Whether the proposed rate design is reasonable;
- Whether the proposed capital structure and return on equity is reasonable;
- Whether the Revenue Decoupling Mechanism (RDM) pilot program should be extended beyond 2020 and, if so, for how long;
- Whether the proposed margin sharing mechanism should be incorporated into the RDM;
- Whether a minimum energy savings level should be required in order to implement a RDM surcharge;
- The impact of suspending the Gas Utility Infrastructure Cost (GUIC) rider;
- Whether the Company intends to continue GUIC rider use after the rate case;

[1] Ex. DER-15 (Lusti Surrebuttal); Ex. DER-22 (Lusti Summary).
[2] Ex. DER-15 (Lusti Surrebuttal).

- The Company's preferred stock redemption;
- The sales forecast accuracy; and
- The Company's decision to propose a change to Conservation Cost Recovery Adjustment (CCRA) factor the in the present docket, instead of a Conservation Improvement Program Tracker/DSM financial incentive docket.[3]

IV. ARGUMENT

1. BURDEN OF PROOF:

The Company bears the burden of showing that its proposed rates are reasonable. Minn. Stat. § 216B.16, subd. 4 (2018). Minnesota law requires that every rate established by the Commission must be just and reasonable, and that any doubt should be resolved in favor of the consumer:[4]

> Every rate made, demanded, or received by a public utility . . . shall be just and reasonable. . . . Any doubt as to reasonableness should be resolved in favor of the consumer.

The Minnesota Supreme Court found that the utility must prove the facts required to sustain its burden by a fair preponderance of the evidence.[5] The Court described the Commission's role, both quasi-judicial and partially legislative, in determining just and reasonable rates in a rate proceeding:[6]

> [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.

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[3] *Id.* at 2.
[4] Minn. Stat. § 216B.03 (2018).
[5] *In re N. States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987).
[6] *Id.* at 722–23.

Moreover, the Court held that the utility "had at all times the burden of proving the proposed rate change."[7]

To the extent that the Company did not satisfy its burden of demonstrating that its proposed recovery was reasonable, the Department recommended adjustments to Great Plains' request to conform to the requirement that rates must be fair and reasonable.

2. Summary of Financials: Rate Base, Operating Income, and Expenses

Many financial issues initially reviewed and identified in the Department's initial testimony were subsequently resolved between the Department and the Company. This Department Initial Brief includes an analysis of each disputed issue, as well as discussion demonstrating that each resolution is reasonable. The financial issues,[8] disputed and resolved, between the Department and the Company are provided as follows:[9]

Disputed in whole or part	Fully Resolved
A. Dues to Minnesota Utilities Investor Assn.	A. Benefits Expense
B. Incentive Compensation Not Paid	B. Subcontracted Labor Expense
C. Rate Case Expenses Not Incurred	C. CIP Exp & CCRA Adjustment Factor
	D. GUIC Rider
	E. Average Rate Base-2020 Beginning Balance Placeholder
	F. Cash Working Capital
	G. Rate Base
	H. Bonus Expense
	I. Interest Expense Synchronization

[7] *Id.* at 725 (holding that a rebuttable presumption of reasonableness is not created by the utility).
[8] Sections three and four of this brief include issues relating to resolved and unresolved rate base, operating income and expenses. Cost of capital is discussed in sections five and six below, and the sales forecast is discussed in section seven.
[9] Ex. DER-14 at 13-14 (Byrne Surrebuttal) Ex. DER-15 at 9-10 (Lusti Surrebuttal), Ex. DER-21 (Byrne Summary Statement), and DER-22 (Lusti Summary).

3. Disputed And Partly Disputed Financial Issues

A. Dues Proposed to be Paid to Minnesota Utilities Investor Association (MUI) and the Edison Electric Institute ("EEI")

Disputed between DER and Great Plains: The DER recommended that the Commission disallow GP's proposed test year expense of MUI dues. The OAG recommended disallowance of MUI dues and EEI dues. Ex. 6 at 7-10 (Byrne Direct); Ex. 14 at 6-10 (Byrne Surrebuttal); Ex. DER-21 (Byrne Summary); Ex. GP-21 at 21-22 and TRJ-1 at 3 (Jacobson Direct); Ex. GP-23 at 2-4 (Jacobson Rebuttal); Ex. GP-24 (Jacobson Summary); Ex. OAG-1 at 7-9 (Lebens Direct); Ex. OAG-2 at 7-9 (Lebens Surrebuttal); Ex OAG-3 (Lebens Summary).

In the Company's Initial Filing,[10] Great Plains provided an itemized schedule of all industry dues paid in 2018 totaling $34,589, along with projections for each dues amount in 2019 totaling $41,872. The 2020 projected test-year amount was held at the 2019 total of $41,872.[11]

In her review of the Company's filing Department witness, Ms. Angela Byrne, identified concerns regarding dues the Company proposed to be paid to an organization called the "Minnesota Utility Investors Association" (MUI), whose name implied that the association focuses on investors, rather than utility operations,[12] and whose purpose, according to the Company, is to represent the interests of investors owning shares in utility companies operating in Minnesota, and *whose principal objective is to enhance the voice and impact of utility shareholders in the development of federal, regional and state legislative and regulatory policy*."[13] The MUI describes itself as "representing the interests of utility shareholders."[14] It sponsors member meetings, a statewide annual meeting, an annual Day at the Capitol (including making appointments for members to meet their legislators), and tours of energy facilities. Past

[10] Ex. GP-2 (Vol. III, Statement C, Schedule C-2, page 20 of 27)(Sept. 27, 2019)(eDocket No. 20199-156151-04).
[11] Ex. DER-6 at 7 (Byrne Direct).
[12] *Id.* at 8.
[13] Ex. GP-21, TRJ-1 at 3 (Jacobson Direct); Ex. DER-6 at 4 (Byrne Direct) (emphasis added).
[14] Ex OAG-2 at 8-9 (Lebens Surrebuttal).

tours included nuclear, wind, solar, coal, and hydro facilities; but, of note, no natural gas transportation or distribution tours. Supporting membership-level members may bring to events a spouse or other guest for free. Tours included catered meals and transportation from around the state to annual meetings and the Day on the Capitol events.[15]

Basic standards of utility regulation require that the amount and purpose of any organizational dues expense that a utility proposes ratepayers pay must be reasonable and in the best interests of the utility's ratepayers.[16] The Commission does not impose on customers the expense of dues when it has not been shown that customers receive any benefit from the organizations receiving the dues, as may be the case when the organizations are lobbying or social in purpose, or where there is no connection between the expense and reasonable and reliable utility service.[17] A utility seeking recovery of dues expenses should include testimony explaining whether the primary purpose of the organization is educating and informing public utility employees about providing improved utility service; or training employees to become better qualified in providing improved utility service; or if membership in the organization is a necessary qualification for public utility employees to carry on their employment responsibilities; or if membership provides essential information to the utility.[18]

With respect to the reasonableness of investor relations expenses generally, in some cases the Commission has allowed 50 percent recovery of the expenses that utilities proposed to be included in base rates, finding that these expenses benefit ratepayers in as much as they keep

[15] Copies of the Association's webpages were included with Ms. Byrne's testimony at Ex. DER-6 at 8-9, ACB-3 (Byrne Direct).
[16] Ex. DER-14 at 8-9, ACB-S-1 (Byrne Surrebuttal) (STATEMENT OF POLICY ON ORGANIZATION DUES, (MPUC June 14, 1982) (This is one of eight policies on recurring rate case issues adopted to provide "advance guidance on the likely treatment of these issues."))
[17] *Id.*
[18] *Id.*

utility financing at a favorable cost. Such investor relations expenses include costs incurred for convening the utility's annual shareholders' meeting, maintaining shareholder records, and recruiting equity capital.[19] However, it has been the conclusion of the Department, Administrative Law Judges, and the Commission that a portion of these typical investor relations costs, like the annual shareholders' meeting, benefit *only* shareholders. When the utility does not provide a detailed breakdown of the individual costs within the investor relations category, the Commission has denied 50 percent of recovery as a way to acknowledge shareholder benefit.[20]

The Department concluded that the stated mission and activity of MUI do not align with the general regulatory principal that rate-recoverable expenses include only those that relate to utility operations of benefit to ratepayers. Specifically, the activities of MUI do not enhance or facilitate equity funding specifically for Great Plains. MUI is not responsible for shareholder record keeping, nor does it specifically seek new investors to keep utility financing costs reasonable. MUI's mission instead is expressly to empower utility shareholders in the legislative and regulatory policy-making processes.[21] Importantly, the Company's payments to MUI do not

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[19] Ex. DER-6 at 9-10 (Byrne Direct), Ex. DER-14 at 8 (Byrne Surrebuttal).

[20] Ex. DER-6 at 9-10 (Byrne Direct) (*citing In re Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-12-961, ORDER – FINDINGS OF FACT, CONCLUSIONS AND ORDER at 46, Order Point 2 (Sept. 3, 2013); *In re Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 20-22 (June 9, 2014); *In re Application of Northern States Power Company, D/B/A Xcel Energy, for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-13-868, Byrne Surrebuttal at 4 (Aug. 4, 2014); *In re Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 71, Order Point 2 (June 3, 2016); *In re Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G011/GR-15-736, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 54, Order Point 2 (Oct. 31, 2016).)

[21] Ex. DER-6 at 9 (Byrne Direct).

enhance utility employee knowledge or skills.[22] And, unlike officers and employees, shareholders have no duty to ratepayers or even to the utility, fiduciary or otherwise, and they are not required to use information and/or support provided by MUI in the best interest of ratepayers or the Company.

Based on the information provided by the Company and obtained independently, Ms. Byrne concluded in her direct testimony that Great Plains has not shown that it is reasonable for ratepayers to pay for its dues to the MUI. She recommended excluding the proposed $11,500 of organization dues from the Company's 2020 test-year expenses.[23]

In his rebuttal testimony, Great Plains witness Mr. Jacobson offered additional support for its proposed MUI dues expense stating that, MUI focuses on legislation and regulatory policy that impacts utilities and utility customers. Mr. Jacobson said that Great Plains' invoice from MUI indicated that 35 percent of the annual dues was related to lobbying and that amount was excluded from the Company's filing request of $11,500, and a further exclusion would unfairly harm the Company. Mr. Jacobson provided no documentation to support his statements.

Ms. Byrne did not find these statements persuasive, and in her surrebuttal testimony, continued to conclude that the Company had not met its burden to show that these dues are beneficial to ratepayers. She explained that, in light of Mr. Jacobson's rebuttal argument, she would have expected Mr. Jacobson to substantiate the reasonableness of the claimed expense by providing the invoice from MUI, or at the very least, the calculation showing the exclusion of the 35 percent lobbying expenses. He provided neither.[24]

[22] Ex. DER-21 (Byrne Summary).
[23] Ex. DER-6 at 10, ACB-3 (Byrne Direct).
[24] Ex. DER-14 at 7 (Byrne Surrebuttal).

Second, she observed that MUI membership is completely optional for both utilities and shareholders and is open only to current shareholders; none of MUI's stated activities focus on recruiting equity investors for the regulated utility. In cases where the Commission has allowed 50 percent recovery of investor relations expenses, the Department, Administrative Law Judges, and the Commission have agreed that there was benefit to ratepayers from a portion of the investor relations activities (*e.g.* costs to maintain shareholder records and recruit equity capital), because obtaining new investors keeps utility financing costs reasonable.[25]

Third, the Company did not show that any the activities of the MUI organization fall within the boundaries described in the Commission's Statement of Policy on Organizational Dues. MUI's work does not enhance employee knowledge or skills in providing safe and reliable utility service.[26]

Finally, in his rebuttal testimony, Mr. Jacobson proposed that, at a minimum, Great Plains should be allowed to recover at least 50 percent of the dues it paid MUI, as a way to acknowledge customer benefits.[27] The Department disagreed. Great Plains' identification of customer benefits was limited to a statement that the MUI dues support efforts that have an impact on legislation and regulatory policy; however, it is likely that such efforts are focused on shareholder, and not necessarily ratepayer, interests. Just because an elective activity has impact on regulatory policy does not mean that it is reasonable for the utility to recover the expense from ratepayers.[28]

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[25] Ex. DER-14 at 8 (Byrne Surrebuttal).

[26] *Id.* at 9. In addition, the Commission stated in its policy that it does not impose on customers dues to organizations that have not been shown to provide customer benefit, "…as may be the case when the organizations are lobbying or social in purpose…." *Id.*

[27] Ex. GP-23 at 2-3 (Jacobson Rebuttal); Ex. DER-14 at 7 (Byrne Surrebuttal).

[28] Ex. DER-14 at 9 (Byrne Surrebuttal).

Based on all of the information provided by the Company, including its rebuttal testimony, and the Commission's guidance on organizational dues, Ms. Byrne concluded that Great Plains had not shown that it is reasonable for ratepayers to pay for MUI dues. Great Plains did not substantiate that the requested amount is accurate or properly excludes stated lobbying costs.[29] The estimated financial impact of this recommendation reduces test-year operations and maintenance (O&M) expenses (of which organizational dues expense is a part) by $11,500.[30]

B. Incentive Compensation Not Paid

> **Agreed between DER and Great Plains:** The Department agreed to the Company's proposed test-year expense for incentive compensation, under which ratepayers would pay for 100 percent of its employees' target level incentive compensation, capped at 15 percent of salary.
> **Disputed between DER and Great Plains:** The Company failed to demonstrate that, unlike other investor-owned utilities in Minnesota, it should not be required to file an annual incentive compensation report or refund to ratepayers incentive compensation the Company does not pay to employees. Ex. DER-22 (Lusti Summary); Ex. DER-7 at 8-12 (Lusti Direct); Ex. DER-15 at 4-7 (Lusti Surrebuttal); Ex. GP-21 at 18 (Jacobson Direct); Ex. GP-23 at 5-6 (Jacobson Rebuttal); Ex. GP-24 (Jacobson Summary).

The incentive compensation expense issue has two interrelated parts: (1) the level of incentive compensation to be included in the test-year expenses, and (2) whether Great Plains should be required to file and annual report showing whether the incentive compensation was actually paid to employees under the program. The Department witness, Mr. Lusti, indicated that the Department's acceptance of the proposed level of incentive compensation was premised on the filing of an annual incentive compensation report to determine whether refunds need to be made.[31]

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[29] Ex. DER-21 (Byrne Summary).
[30] Ex. DER-6, ACB-3 (Byrne Direct); Ex. DER-14 at 10 (Byrne Surrebuttal).
[31] Ex. DER-7 (Lusti Direct at 9). (Mr. Lusti testified: "Q: Do you agree that Great Plains included a reasonable amount of incentive compensation in the test year? A. Yes. *However,* since the Company's proposal is based upon all employees earning their individual 100 percent of target level incentive compensation, capped at 15 percent of salary, it is reasonable for the (Footnote Continued on Next Page)

As to the amount of the test-year expense, the Department determined that the Company included a reasonable amount of incentive compensation in the test year. The Company's proposed test-year level of incentive compensation was $261,892,[32] an amount that was based on the use of a 9.5 percent incentive compensation rate, applied to the 2020 test-year straight-time and vacation labor expense.[33] The "9.5 percent incentive compensation rate" was the result of dividing the total incentive compensation payout, based on the 100 percent target level of those in each job classification, capped at 15 percent of salary, by the total salary of all job classifications eligible for incentive compensation.[34]

Turning to the second part of this issue, the Commission has followed the practice of requiring investor-owned utilities to track, report, and return to ratepayers unpaid incentive compensation since 1994. It continues to do so, requiring other utilities, such as Xcel Energy, Minnesota Power, and CenterPoint Energy to track payment of incentive compensation, file annual incentive compensation reports, and refund amounts not actually paid under their incentive compensation programs.[35]

The Commission first adopted this policy in Xcel's 1992 Electric Rate Case, requiring:[36]

(Footnote Continued from Previous Page)
Company to refund to ratepayers all incentive compensation amounts approved by the Commission and included in base rates that are not paid out to employees under the program. To determine the amount of actual incentive compensation paid that is recoverable from ratepayers, the Company should apply the 15 percent cap to each employee's salary.") (emphasis added).

[32] Ex. DER-7 at 8 (Lusti Direct); Ex. GP-2, Vol. III, Statement C, Schedule C-2, page 10 of 27

[33] Ex. DER-7, DVL-8 (Lusti Direct) (Great Plains' Response to Department IR No. 116).

[34] *Id.* at 9, DVL-8.

[35] *Id.* at 10.

[36] *Id.* at 11 (*citing In the Matter of the Application of Northern States Power Company for Authority to Increase Its Rates for Electric Service in the State of Minnesota (Xcel 1992 Rate Case)* Docket No. E002/GR-92-1185, ORDER AFTER RECONSIDERATION (January 14, 1994) page 25, Ordering Paragraphs 2 and 3.

2. The Company shall record for future refund all incentive compensation payments earned under the terms of the plan and recoverable in rates under this Order but not paid.

3. The Company shall file a report on or before April 1, 1994[37] and annually thereafter evaluating the operation and performance of its incentive compensation plan. The report shall include, but shall not necessarily be limited to, an accounting of all amounts recorded as earned but not paid, and an evaluation of the plan's success in meeting its stated goals, including overall compensation costs.

Xcel continues to track, file an annual report, and refund unpaid incentive compensation, filing its most recent annual incentive compensation report, for 2018, on May 31, 2019.[38]

Similarly, Minnesota Power (MP) tracks, files annual reports, and refunds unpaid annual incentive compensation. In MP's most recent rate case, the Commission ordered, "[t]he Company shall continue to provide customer refunds in the event that actual payouts are lower than the level approved in rates."[39] In accordance with the Commission order, on July 23, 2019, Minnesota Power filed its annual incentive compensation report for the period January 1, 2018 through December 31, 2018.[40]

CenterPoint Energy also tracks annual incentive compensation, files reports, and is required to refund unpaid amounts. On April 15, 2019, CenterPoint Energy filed its most recent

[37] The Commission approved a later annual filing date in its March 27, 2002 Order. The Order required "that the incentive compensation report will be due on May 21, 2002, and annually thereafter." Xcel Energy requested a later annual filing date because it changed the annual date when incentive compensation payments are made from February 1 to March 15.

[38] Ex. DER-7 at 11 (Lusti Direct) (*citing Northern States Power Co. Report on the Operation and Performance of its 2018 Incentive Compensation Plan*, Docket No. E,G002/M-19-375, *Annual Report and Refund Proposal*, (May 31, 2019).

[39] *Id*. at 11 (*citing In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E015/GR-16-664, (March 12, 2018) Order Point 22.

[40] *MP Compliance Filing-Incentive Compensation*, July 23, 2019.

annual incentive compensation report[41] pursuant to the Commission's requirements in CenterPoint Energy rate cases.[42]

It is appropriate that the same practice be applied in the case of Great Plains because Great Plains in the recent past has recovered from ratepayers amounts for incentive compensation that were earned by, but not paid to, employees. Department witness, Mr. Dale Lusti testified that in February 2016, the Department learned that Great Plains did not plan to pay its employees incentive compensation based on 2015 results.[43]

In this instant Great Plains rate case, the Department concluded that, since the Company's proposed test-year incentive compensation expense was based upon *all* employees earning their *individual* 100 percent of target level incentive compensation, capped at 15 percent of salary, it is reasonable for the Company to refund to ratepayers the amount of incentive compensation that is approved and included in base rates but is not paid annually to employees under the program. To determine the amount of actual incentive compensation paid that is recoverable from ratepayers, the Company should apply the 15 percent cap to each individual employee's salary (as Xcel Energy, Minnesota Power, and CenterPoint Energy do) and the Commission should require Great Plains to file an annual report on incentive compensation

[41] *CenterPoint Annual Incentive Compensation Compliance Filing*. April 15, 2019.

[42] Ex. DER-7 at 12 (Lusti Direct) (*citing In the Matter of the Application of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Rates for Natural Gas Utility Service in Minnesota, Docket No. G008/GR-17*-285 ORDER ACCEPTING AND ADOPTING AGREEMENT SETTING RATES (July 20, 2018) (accepting an Offer of Settlement dated March 7, 2018, the terms of which are detailed in 17-285, Rebuttal Testimony of Randolph H. Sutton, page 7 (Feb. 5, 2018); and *In the Matter of the Application of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Rates for Natural Gas Utility Service in Minnesota*, Docket No. G008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (June 3, 2016)).

[43] *Id.* at 12 (*citing In the Matter of the Application of Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc. for Authority to Increase Rates for Natural Gas Service in Minnesota* (Docket No. G004/GR-15-879), *Lusti Direct* at 4-5 (Feb 23, 2016).

within 30 days after incentive compensation is normally scheduled for payout. The report should include at a minimum the following: [44]

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

In rebuttal testimony, the Company did not agree with the Department's recommendation to file an annual incentive compensation report. To demonstrate the reasonableness of his 100 percent of target recommendation *without* an annual incentive compensation report, GP witness, Mr. Jacobson said that in Great Plains' last rate case, incentive compensation was based on a three-year average of the incentive payments. He said that using the actual 2016, 2017 and 2018 payout percentages of 101.9, 113.2 and 95.1 percent of target, respectively, would produce an average of 103.4 percent of target. He implied that use of a 100 percent of target better matched the incentive compensation provided to employees with an appropriate and normalized level of expense, and thus the Company should not be required to file an annual report.[45]

In response, Department witness Mr. Lusti explained that, while he agreed that the 100 percent of target is a better match than a three-year average, an annual report is still needed

[44] *Id*. at 9-10 (Lusti Direct); Ex. DER-15 at 4 (Lusti Surrebuttal).
[45] Ex. DER-15 at 5 (Lusti Surrebuttal).

because, unless required to do so, the Company can elect not to pay any incentive compensation in any given year if it so chooses. He observed that, in fact, the Company chose not to pay any incentive compensation for 2015 results.[46] Great Plains' failure to pay its employees any incentive compensation is similar to what led the Commission in 1994 to adopt its current reporting practice, and is what led the Department in this instant case to recommend that Great Plains be required similarly to report on its incentive compensation program.[47]

At the evidentiary hearing during cross examination, Mr. Lusti was told that in 2015, the reason the Company did not pay out incentive compensation was because the incentive compensation metrics were not met.[48] The implication was probably that GP did not meet its earning's requirement, thus incentive compensation was not earned. Mr. Lusti's response was that ratepayers whose rates included an amount for incentive compensation, do not care what the reason is for GP not paying employees what the customer has paid GP for.[49] Thus, incentive compensation not paid to employees should be refunded, and a report is the Commission's method for determining that.

In rebuttal testimony, Mr. Jacobson characterized the Commission practice of requiring annual incentive compensation reports as a "non-reciprocal, single-issue" rate making practice that should not be applied to Great Plains. Nothing in the Company's testimony, however, demonstrated a reason for the Commission to abandon this long-standing practice; Mr. Lusti

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[46] *Id.*
[47] *Id*. at 6-7 (Lusti Surrebuttal).
[48] Tr. at 46.
[49] Tr. at 46.

observed that the Commission does not consider the filing of annual incentive compensation reports to be unreasonable "non-reciprocal single-issue ratemaking."[50]

If an expense is authorized by the Commission as an approved test-year expense, a rate-regulated utility can build that cost into base rates and collect that expense from ratepayers until such time as the utility chooses to file a new rate case. However, as Mr. Lusti explained under cross-examination, in instances in which, for whatever reason, the utility does not pay the expense, as can be the case regarding incentive compensation, the Commission has required a ratepayer refund if the utility does not incur that expense.[51] It is not reasonable for ratepayers to pay rates premised on the award of annual employee incentive compensation that Great Plains does not actually award.[52] Incentive compensation included in rates but not paid to employees should be refunded to ratepayers, and an annual report is the Commission's method for determining whether a refund is appropriate, and in what amount.

C. Rate Case Expenses Not Incurred

Resolved between DER and Great Plains: Great Plains and the Department agreed on the amount of rate case expense that should be recoverable from ratepayers, and on the amortization period.
Disputed between DER and Great Plains: Great Plains and the Department disagree on whether Great Plains should track any over-recovery from ratepayers of rate case expenses, and apply that credit to the revenue requirement in its next rate case. Ex. GP-21 at 23-24 (Jacobson Direct); Ex. GP-23 at 6 (Jacobson Rebuttal); Ex. DER-7 at 13-14 (Lusti Direct); Ex. DER-15 at 7-8 (Lusti Surrebuttal); Ex. DER-22 (Lusti Summary Statement).

Great Plains estimated its rate-case expense in this proceeding to be \$592,555.[53] The estimate included six categories of cost as follows:[54]

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[50] *Id*. at 6 (Lusti Surrebuttal).
[51] Tr. at 46-50.
[52] *Id*. at 50.
[53] Ex. GP -2 Statement C Operating Income, Workpapers at C2-19.
[54] Ex. DER-7 at 13 (Lusti Direct).

(1) Rate of Return Consulting Fees;
(2) Outside Legal Fees;
(3) Great Plains' Staff Hearing Expense;
(4) Montana-Dakota Staff Public Input Meeting Expense;
(5) State Agency Fees; and
(6) Administrative Costs (Federal Express and Miscellaneous).

Based on its review, the Department did not challenge the Company's estimate of the rate case expenses[55] nor the Company's proposal to use to a four-year amortization period to collect the expense.[56]

The Department disagreed with the Company, however, that possible over-recovery would be reasonable. In light of possible over-recovery of rate case expenses, the Commission's past practice, as seen in Great Plains' most recent past rate case,[57] required the Company to credit any over-recovery to future rate case revenue requirements. In Great Plains' last case, the Commission ordered:

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

Consistent with the Commission's past requirements, the Department recommends that Great Plains be required to track any over-recovery from rate payers of rate case expenses, and to credit the excess amount it collects to the revenue requirement in Great Plains' next rate case.[58]

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[55] *Id*. at 14 (Lusti Direct).
[56] Ex. GP-21 at 23 (Jacobson Direct); Ex. DER-7 at 14 (Lusti Direct).
[57] *In the Matter of the Petition by Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G004/GR-15-879, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at point 8 (September 6, 2016).
[58] Ex. DER-7 at 14 (Lusti Direct); Ex. DER-15 at 8 (Lusti Surrebuttal); Ex. DER-22 (Lusti Summary Statement).

4. Undisputed Financial Issues

A. Benefits Expense

- **Resolved between DER and Great Plains:** The Company's direct testimony proposed a test-year benefits expense of $727,614. Great Plains thereafter agreed with DER's recommendation to reduce benefits expense by $38,897. Ex. GP-21 at 19 (Jacobson Direct); Ex. DER-6 at 3-7, ACB-2 (Byrne Direct); Ex. DER-14 at 2-3 (Byrne Surrebuttal); Ex. GP-23 at 3-4 and TRJ-3 (Jacobson Rebuttal); Ex. GP-24 (Jacobson Summary); Ex. DER-21 (Byrne Summary).

Great Plains' initial case proposed test-year benefits expense consisting of several items in the projected amounts shown in Table 1, below:[59]

Table 1: Company-Proposed Test-Year Benefits Expenses

Expense Category	Amount
Medical/Dental	$504,227
Pension	$13,156
Post-Retirement	($93,337)
401(k)	$279,658
Workers Compensation	$20,314
Other Benefits	$3,596
Total	**$727,614**

In her investigation, Ms. Byrne issued an information request (IR) that asked for GP's historical, actual benefits expenses for 2016 through 2018, as well as an updated projection for 2019 that would include the 2019 calendar year actual benefits expenses where actual data were available.[60] In response, GP provided the information shown below in Table 2.[61]

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[59] Ex. GP-21 at 19 (Jacobson Direct); Ex. DER-6 at 4 (Byrne Direct) (*citing* Ex. GP-2 (Vol. III, Statement C, schedule C-2, page 13 of 27, fns.) (Sept. 27, 2019).

[60] Ex. DER-6 at 4 (Byrne Direct) (*citing* Department Information Request (IR) No. 106).

[61] *Id.* at 4-5, ACB-1.

Table 2: Great Plains Historical and Updated Benefits Expenses

Year	2016	2017	2018	IR No. 106 Projected 2019
Medical/Dental	$377,404	$408,415	$398,409	$458,090
Pension	$21,525	$14,972	$19,375	$61,633
Post Retirement	$(7,266)	$(20,901)	$(68,048)	$(92,112)
401(k)	$269,808	$284,671	$252,111	$248,111
Workers Compensation	$30,349	$18,464	$18,913	$22,126
Other Benefits	$4,482	$5,299	$3,199	$3,505
Total	**$696,302**	**$710,920**	**$623,959**	**$701,353**

The updated projected 2019 benefits expense of $701,353 is $33,879 less than the $735,232 amount proposed in the Company's Initial Filing, and was calculated using actual expenses through October 2019, with annualized amounts for the remaining two months of the year.[62] Ms. Byrne observed that the amount of $701,353 was more in line with GP's historical expenses since its last rate case than was the amount shown in Table 1 above, as initially proposed. Further, the individual category percentage increases proposed by GP to estimate 2020 test-year expenses were also in line with previous year-over-year increases for such non-actuarial expenses.[63]

Ms. Byrne concluded that it was reasonable to base the Pension and Post-Retirement expense estimates on actuarial estimates, and to base the remaining expense estimates on reasonable percentage increases from the 2019 projections.[64] Accordingly, she recommended that the 2020 test year be calculated by using the actuarial estimates for Pension and Post-Retirement Benefits, and applying the Company's proposed six percent increase for the Medical/Dental category and three and a half percent increase for 401(k), Workers

[62] *Id.* at 5.
[63] *Id.* at 5-6.
[64] *Id.* at 6.

Compensation, and Other Benefits to the updated projected 2019 amounts provided in response to the Department's IR No. 106.[65]

Ms. Byrne's recommendation results in an overall downward adjustment of the test-year expense in the amount of $38,897, as shown in Table 3.[66]

Table 3: Department-Recommended Test-Year Benefits Expenses[67]

Category	**Company Proposed 2020 Test Year**	**From Table 2 IR No. 106 Projected 2019**	**Adjustment**	**DOC DER Recommended Amount**	**DOC DER Adjustment to 2020 TY**
Medical/Dental	$504,227	$458,090	+ 6%	$485,575	($18,652)
Pension	$13,156	$61,633	Actuarial	$13,156	$ -
Post-retirement	($93,337)	$(92,112)	Actuarial	($93,337)	$ -
401(k)	$279,658	$248,111	+ 3.5%	$256,795	($22,863)
Workers Compensation	$20,314	$22,126	+ 3.5%	$22,900	$2,586
Other Benefits	$3,596	$3,505	+ 3.5%	$3,628	$32
Total	**$727,614**	**$701,353**		**$689,942**	**($38,897)**

Great Plains agreed with this adjustment, which reduces its initial proposed test-year benefits expense of $727,614 by $38,897, to $689,942.[68]

B. Subcontracted Labor Expense

Resolved between DER and Great Plains: The Company agreed with DER's recommendation to reduce test-year subcontractor labor expenses by $81,397. Ex. DER-6, ACB-5 (Byrne Direct); Ex. GP-23 at 4 (Jacobson Rebuttal); Ex. DER-21 (Byrne Summary).

To calculate its proposed 2020 test-year expense for subcontracted labor, Great Plains first estimated its 2019 labor to be $515,563; and then applied a 1.94 percent inflation factor to arrive at its proposed 2020 test-year amount of $525,564.69.[70]

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[65] *Id.*
[66] *Id.*
[67] *Id.* at 7, ACB-2.
[68] Ex. GP-23 at 3-4 (Jacobson Rebuttal). Ex. DER-14 at 3 (Byrne Surrebuttal).
[69] Ex. GP-2 (Vol. III, Statement C, Schedule C-2, page 14 of 27)(Sept. 27, 2019)(eDockets No. 20199-156151-04).

In her review, Ms. Byrne determined that the estimated 2019 subcontracted labor expense did not seem reasonable, when compared with the Company's 2018 actual expense. Great Plains' Minnesota jurisdictional 2018 expense amount was $464,187, which is over $50,000 *less* than the 2019 amount the Company's initial filing projected for its 2019 subcontracted labor expense.[71] In its response to Department IR No. 122, which requested 2016 through 2018 historical actuals and an updated 2019 projection,[72] the Company provided the actual amounts for 2016-2018 and an updated projection for 2019 in below Table 4.

Table 4: Historical and Updated Subcontract Labor[73]

Year	Amount
2016 Actual	$399,118
2017 Actual	$416,029
2018 Actual	$464,187
Updated Projected 2019	$435,715
2020 Proposed Test Year	$525,564

Table 4 shows that the Company's subcontracted labor expense increased from 2016 to 2018, but the updated projection for 2019 showed a decrease in expense from 2018. In fact, the Company's updated projection for 2019 was approximately $80,000 less than the amount the Company had projected in its Initial Filing.[74]

Ms. Byrne concluded that the Company's proposed 2020 test-year subcontracted labor expense amount was not reasonable, in light of its response to IR 122 and Great Plains' failure to provide any information to justify a proposed test-year subcontracted labor expense so much

(Footnote Continued from Previous Page)
[70] Ex. DER-6 at 11 (Byrne Direct).
[71] *Id.*
[72] *Id.*
[73] *Id.* at 11-12, ACB-4.
[74] *Id.* at 12.

higher than the previous four years.[75] She recommended that, because the Company's historical expenses increased through 2018, it would be reasonable to apply to the updated 2019 projected amount, the 1.94 percent inflation factor that Great Plains used to calculate its initial test-year proposal.[76] This results in a test-year subcontracted labor expense of $444,168, which is a downward adjustment of $81,397 from Great Plains' proposed test-year expense of $525,564.[77]

Great Plains agreed with Ms. Byrne's recommended adjustment. In his rebuttal testimony, Great Plains witness Mr. Jacobson stated that, "Great Plains has reviewed its 2019 actual subcontractor labor expense which also tracked with the amount Ms. Byrne used in the development of her recommended $81,397 reduction in test year expenses."[78]

The estimated financial impact of this recommendation reduces test-year O&M expenses (of which subcontracted labor is a part) by $81,397.[79]

C. Conservation Improvement Program (CIP) Expense & Conservation Cost Recovery Adjustment (CCRA) Factor

Resolved between DER and Great Plains: DER recommended approval of Great Plains' proposed level of CIP expense (as the basis for its Conservation Cost Recovery Charge (CCRC) rate). The Company agreed to the Department's recommendation that any changes to the CCRA Factor should be considered and determined in the Company's upcoming annual (2020) CIP tracker and financial incentive proceeding rather than in the instant rate case. Ex. GP-21 at 20 (Jacobson Direct); Ex. DER-6 at 13-16, 21 (Byrne Direct); Ex. GP-31 at 12 (Bosch Direct); Ex. GP-32 at 2-3 (Bosch Rebuttal); Ex. DER-21 (Byrne Summary).

There are two now-resolved issues regarding the topic of Conservation Improvement Program (CIP) expense and Conservation Cost Recovery Adjustment (CCRA) Factor. The first

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[75] *Id.*
[76] *Id.* at 12-13 (*citing* footnotes of Ex. GP-2 (Initial Filing, Vol.III, Statement C, Schedule C-2, page 13 of 27)(Sept. 27, 2019)).
[77] *Id.* at 12-13, ACB-5.
[78] Ex. GP-23 at 4 (Jacobson Rebuttal); Ex. DER-14 at 3-4 (Byrne Surrebuttal).
[79] Ex. DER-6, ACB-5 (Byrne Direct); Ex. DER-14 at 3 (Byrne Surrebuttal); Ex. DER-21 (Byrne Summary).

is the standard rate case issue of the appropriate amount of CIP test-year expense. The second now-resolved issue is the subject of the Commission's NOTICE OF AND ORDER FOR HEARING, which requested the parties develop a record regarding GP's proposal to make a change to the CCRA Factor in the present docket, instead of in a separate docket that was concerned solely with the CIP cost tracker and demand-side management (DSM) financial incentive.[80]

Turning to the first now-resolved issue, Great Plains proposed to include in its 2020 test year $566,621 in CIP expense, which is the same amount as its 2018 actual CIP expense.[81] In her review, Ms. Byrne observed that Great Plains' past CIP status reports[82] showed that the Company typically spent less than its authorized CIP budget, as shown in Table 5.[83]

Table 5: Great Plains' CIP Budgets and Expenditures

Year	Approved Budget	Actual Spend
2013	$821,691	$378,794
2014	$827,718	$327,380
2015	$1,012,597	$724,644
2016	$832,597	$642,143
2017	$885,396	$403,118
2018	$887,408	$566,621
2019	$902,858	

80 NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 22, 2019)(Great Plains proposed a change to the CCRA Factor from the currently approved CCRA Factor amount of (.0337) to (.0599) in this general rate case rather than through a CIP tracker/DSM financial incentive docket.)

81 Ex. GP-2 (Initial Filing, Vol. III, Statement C, Schedule C-2, page 17 of 27) (Sept. 27, 2019); Ex. GP-21 at 20 (Jacobson Direct); Ex. DER-6 at 13 (Byrne Direct) (Mr. Jacobson explained that "Schedule C-2, page 17 shows the base level of Conservation Improvement Program (CIP) expense that Great Plains has included in its distribution margin. Great Plains used the actual expense of $566,621 for 2019 and 2020 as included in Great Plains' annual Status Report in Docket No. G004/CIP-19-287. Great Plains used actual expenses, instead of the budget, because of the extension of the new CIP portfolio to 2021. Any differences from the base will be returned to or collected from customers through the CCRA").

82 Docket Nos. G004/CIP-12-573.01, G004/CIP-12-573.02, G004/CIP-12-573.03, G004/CIP-12-573.04, G004/CIP-16-121.01, G004/CIP-16-121.02.

83 Ex. DER-6 at 14 (Byrne Direct).

For this reason, she concluded that the Company's proposal of $566,621 was reasonable to include in the 2020 test-year expenses, since that amount reflects actual 2018 CIP expenditures. Ms. Byrne further explained that it would be unreasonable to include in the test-year expenses expenditures that Great Plains did not expect to incurs.

Turning to the second issue, Great Plains' Initial Filing proposed not only to update the CCRC in this rate case, but also to change the CCRA factor in this rate case, so that the CCRC and the CCRA factor, combined, would recover the same amount that the CCRC and the CCRA factor, combined, were recovering prior to this rate case.[84]

However, Great Plains' proposal is not reasonable because, when calculating the CCRA Factor each year, Commission practice requires a "thorough review" of the Company's current CIP tracker[85] balance,[86] but Great Plains provided no information about the CIP tracker balance to support its proposed change to the CCRA Factor.[87] Ms. Byrne explained that updating the CCRA Factor at the time the CCRC is updated in a rate case may be reasonable, but the method the Company proposed here was not reasonable because it was not based on an assessment of the

[84] Ex. GP-31 at 12 (Bosch Direct); Ex. DER-6 at 14 (Byrne Direct).
[85] The CIP cost tracker records revenues collected through the CCRC and the CCRA Factor, actual CIP expenditures, Commission-approved financial incentives (financial "rewards" to utilities as an incentive to achieve certain levels of energy savings), carrying charges, and any adjustments that may occur over the period the CCRA is in place. Ex. DER-6 at 15 (Byrne Direct).
[86] Ex. DER-6 at 16 (Byrne Direct) (*citing In the Matter of Great Plains Natural Gas Co.'s 2015 Demand-Side Management Financial Incentive and Annual Filing to Update the CIP Rider*, Docket No. G004/M-16-384, ORDER APPROVING TRACKER ACCOUNT, APPROVING FINANCIAL INCENTIVE, SETTING CARRYING-CHARGE RATE, AND SETTING CONSERVATION COST RECOVERY ADJUSTMENT at 4, fn.5 (Nov. 23, 2016)) (emphasis added)(The Commission determined that, "The Department also claimed that Great Plains had been charging a CCRA not approved by the Commission. Great Plains disagreed, stating that its current -$0.0079/Dth CCRA was part of the interim tariffs approved by the Commission in the Company's recent rate case. However, the Commission clarifies that the CCRA *should be adjusted only after a thorough review of Great Plains' CIP tracker.*" (Emphasis added.)
[87] *Id*. at 15.

current CIP tracker balance.[88] Ms. Byrne recommended that the Commission approve Great Plains' proposed CCRC but deny the Company's request to update the CCRA Factor in this proceeding.[89]

Great Plains agreed with the Department's recommendation. Company witness Ms. Bosch said "Great Plains does agree that the CCRA should be updated in its next tracker filing to better match the actual CIP expenditures, financial incentives, carrying charges, and adjustments that may occur over the period the CCRA is in place…. Great Plains next CIP tracker filing will be filed no later than May 1, 2020."[90]

D. Continuation of the Gas Utility Infrastructure Cost (GUIC) Rider

Resolved between DER and Great Plains: DER did not have a recommendation on the GUIC rider. The Company's actions, and explanation of intentions regarding its GUIC rider, align with DER's understanding of how the rider should interact with Great Plains' rate case. Ex. DER-6 at 17-19 (Byrne Direct); Ex. DER-14 at 5-6 (Byrne Surrebuttal). Ex. DER-21 (Byrne Summary).

The Great Plains' Initial Filing proposed to include in base rates the costs associated with the assets currently being recovered in its approved Gas Utility Infrastructure Cost (GUIC) rider adjustment factors established in Docket No. 18-282.[91] Great Plains also requested that the

[88] Moreover, Great Plains' CCRA Factor did not change with implementation of interim rates, as proposed. Great Plains' December 2, 2019 Interim Rates Compliance Filing in this case did not include the Conservation Improvement Program Adjustment Clause tariff, Sheet No. 5-111, that would state the current CCRC and CCRA Factor. *Id*. at 16.

[89] *Id*. at 16 (Byrne Direct)(Under this recommendation, the Commission would consider any update to the CCRA Factor that may subsequently be needed in the Company's upcoming annual CIP tracker and financial incentive filing to be submitted by May 1, 2020); Ex. DER-14 at 4 (Byrne Surrebuttal); Ex. DER-21 (Byrne Summary).

[90] Ex. GP-32 at 2-3 (Bosch Rebuttal).

[91] *Great Plains Natural Gas Co. (Great Plains), a Division of Montana-Dakota Utilities Co., Annual Report and Petition for approval of recovery of updated Gas Utility Infrastructure Costs (GUIC) under its GUIC Adjustment Tariff for 2018*, PUC Docket No. G004/M-18-282.

Commission approve the 2019 projects it had submitted in Docket No. 19-273[92] and allow the Company to suspend the GUIC rider rate upon the implementation of interim rates, because the Company had included those same 2019 projects in the rate base in this rate case.[93]

The Commission's NOTICE OF AND ORDER FOR HEARING required that parties develop a record regarding two questions: (1) what is the impact of suspending the Gas Utility Infrastructure Cost (GUIC) rider; and (2) did the Company intend to continue use of the GUIC rider subsequent to the rate case.[94]

As to the first question, the impact of suspending the GUIC rider during the rate case, Great Plains initially planned to continue its GUIC rider during its rate case and incorporate the revenue requirement from rider-eligible assets at the end of the rate case. However, upon requests from Department analysts, the Company agreed to roll its rider revenue requirements into its rate case at the beginning of its test year. Ms. Byrne explained that whether a utility incorporates its rider-eligible revenue requirements at the beginning or at the end of its test year ultimately has the same financial effect. However, rolling the rider revenue requirements in at the beginning of the test year (and suspending the rider) leaves less opportunity for double-recovery by eliminating the need for a corresponding adjustment in the interim rate refund calculation.[95]

Incorporating a rider's revenue requirements at the beginning of a utility's test year consists of two steps. First, revenue to be collected through the rider during the test year is set to

[92] *Great Plains Natural Gas Co. (Great Plains), a Division of Montana-Dakota Utilities Co., Annual Report and Petition for approval of recovery of updated Gas Utility Infrastructure Costs (GUIC) under its GUIC Adjustment Tariff for 2019*, PUC Docket Mo. G004/M-19-273.
[93] Ex. GP-21 at 5 (Jacobson Direct).
[94] NOTICE OF AND ORDER FOR HEARING at 2 (Nov 22, 2019).
[95] Ex. DER-6 at 18 (Byrne Direct).

zero, and is instead included in the interim rates set while the rate case is pending. Second, the revenue requirements (expenses) related to the rider-eligible assets are included in the utility's test-year revenue deficiency.

Ms. Byrne explained that the net effect on ratepayers is zero because this process merely changes the mechanism for recovery of previously-approved revenue requirements from the rate rider factor to base rates.[96]

As to the second of the Commission's questions, regarding whether Great Plains intends to use the GUIC rider subsequent to the rate case, the Company responded in the affirmative to Department IR No. 102, indicating that it planned to continue to utilize the GUIC rider subsequent to the rate case.[97] Ms. Byrne observed that the Company's actions, and its explanation of intentions regarding its GUIC rider, align with the Department's understanding of how the GUIC rider should interact with Great Plains' rate case.[98]

E. Rate Base--2020 Beginning Balance for Calculating Average Rate Base

Resolved between DER and Great Plains: Great Plains agreed to DER's recommendation that the Company's 2020 test-year average rate base should be calculated by using GP's 2020 beginning rate base balance (reflecting actual 2019 ending balance) and the projected 2020 additions Great Plains proposed in its initial case. Ex. GP-2, Statement B - Rate Base; Ex. GP-21 at 8-10 (Jacobson Direct); Ex. GP-23 at 4-5 (Jacobson Rebuttal); Ex. GP-24 (Jacobson Summary); Ex. DER-6 at 17 (Byrne Direct); Ex. DER-14 at 10-13, ACB-S-2 (Byrne Surrebuttal); Ex. DER-21 (Byrne Summary); Ex. DER-15 at 2, DVL-S-3, DVL-S-4, DVL-S-8, column (c) (Lusti Surrebuttal).

Test-year rate base is a projection consisting of the average of the 2020 projected beginning and ending rate base balances. The timing and schedule for this case, however,

[96] Ex. DER-6 at 18 (Byrne Direct).

[97] *Id.* at 18-19, ACB-6 (The response to IR No. 102 stated: "The Company plans to file an update in the Spring of 2020 that will focus on the true up of the over- or under-recovery in the rider's tracker balance as of December 31, 2019. The Company also plans to continue to utilize the GUIC rider for future recovery of GUIC-eligible projects beginning in 2021.")

[98] *Id.* at 19 (Byrne Direct).

allowed Great Plains to update the 2020 beginning balance to reflect the 2019 actual ending balance. If Great Plains plans to carry over any incomplete 2019 projects into the 2020 test year, the Company should explain how finishing these incomplete projects in 2020 will or will not delay 2020 projects into 2021.[99]

Ms. Byrne recommended that the revenue requirement approved in this proceeding be based on Great Plains' update of its 2020 beginning rate base balance to the actual amount. She further recommended that the Company's projected 2020 additions be held at the level the Company proposed in its initial case, in the amount of $4,645,785.[100]

Using those guidelines, she concluded that the Commission should approve the Company's 2020 test-year average rate base that reflects the 2020 beginning rate base balance (reflecting the actual 2019 amount) and the projected 2020 additions at the level Great Plains proposed in its initial case.[101]

Great Plains agreed to these recommendations.[102] This adjustment for the 2019 year-end update resulted in an increase to the test-year rate base by $930,854.[103]

F. Cash Working Capital

> **Resolved between DER and Great Plains:** the Company did not include cash working capital in its test-year rate base, and the Department did not recommended that a cash working capital component be calculated. Ex. DER-7 at 7 (Lusti Direct).

Great Plains did not calculate a cash working capital component. Although most investor-owned utilities perform a lead/lag study to calculate a cash working capital component of their rate base, Great Plains historically has not performed such a study. Thus, the Company did not include cash working capital in its test-year rate base. The Department concludes that

[99] *Id*. at 17 .
[100] Ex. DER-14 at ACB-S-1 (Byrne Surrebuttal).
[101] *Id*. at 15 (Byrne Surrebuttal).
[102] *Id*. at 10-13, ACB-S-1 (Byrne Surrebuttal). Ex. DER-21 (Byrne Summary).
[103] Ex. DER-15 at 2, DVL-S-8, column (c) (Lusti Surrebuttal).

there is no need for the Company to be required to perform such a study for the purposes of this rate case. Ex. DER-7 at 7 (Lusti Direct).

G. Bonus Expense

Resolved between DER and Great Plains: The Department agreed that the $9,509 proposed by the company for bonuses is reasonable. Ex. GP-2, Volume III, Statement C, Schedule C-2, Page 10 of 27; Ex. DER-7 at 12-13, DVL-9 (Lusti Direct).

The amount of bonuses and commissions Great Plains has included for test-year recovery from ratepayers is $9,509.[104] The Department agreed with the Company that $9,509 is a reasonable amount of bonuses and commissions to be recovered from ratepayers because the items included in recoverable bonuses and commissions include sign-on and relocation bonuses, referral awards, retirement awards, and service awards.[105] Because the Company no longer includes long-term incentive compensation in recoverable bonuses and commissions, the Department concludes that the $9,509 amount appears reasonable.[106]

H. Interest Expense Synchronization

Resolved between DER and Great Plains: The Company calculated its interest-expense deduction for test-year income tax purposes by multiplying its rate base by the weighted cost of long-term and short-term debt, which is 2.277 percent. The Department agreed with this methodology. The OAG did not take a position on this issue. Ex. GP-2, Statement C - Operating Income, Schedule C-5, Page 2 of 5; Ex. GP-21 at 25 (Jacobson Direct); Ex. DER-7 at 15 (Lusti Direct); Ex. DER-15 at 8, DVL-S-7 (Lusti Surrebuttal).

Great Plains calculated its interest-expense deduction for test-year income tax purposes by multiplying its rate base by the weighted cost of long-term and short-term debt, which is 2.277 percent. The Department agreed with this calculation method.[107]

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[104] Ex. GP-2, Volume III, Statement C, Schedule C-2, Page 10 of 27; Ex. DER-7 at 12 (Lusti Direct).
[105] Ex. DER-7, DVL-9 (Lusti Direct); (Great Plains' Response to Department IR 117).
[106] *Id.* at 13.
[107] *Id.* at 15.

The Department's adjustment for interest synchronization is set out in an attachment to Mr. Lusti's surrebuttal testimony.[108] That attachment details the calculation of the DER's adjustment to the test-year federal and state income tax, which results in a $6,092 decrease to the test-year income tax.[109]

5. COST OF CAPITAL: RETURN ON EQUITY (ROE)

ROE

Disputed between DER and Great Plains: DER recommended an ROE of 8.82 percent.[110] Great Plains recommended an ROE of 10.20 percent.[111]

Flotation Costs

Disputed between DER and Great Plains: Great Plains proposed a flotation cost adjustment of 0.10 percent (ten basis points).[112] DER recommend a flotation cost adjustment of 0.05 percent (five basis points).[113]

A. Introduction

As part of this proceeding, the Commission must determine what constitutes a fair overall rate of return (ROR), also called cost of capital, for Great Plains. ROR is calculated as the average of reasonable costs of long-term debt, short-term debt, and equity, weighted by the amount of each type of financing the Company uses.[114] In general, the cost of equity equals the return on equity (ROE) that Great Plains must pay to induce equity investments in its regulated operations.

Department witness Mr. Craig Addonizio provided DER's recommendations regarding a fair ROE and a fair overall ROR for Great Plains. Mr. Addonizio's recommendation

[108] Ex. DER-15 at DVL-S-7 (Lusti Surrebuttal).
[109] *Id.* at 8 (Lusti Surrebuttal).
[110] Ex. DER-9 at 4 (Addonizio Surrebuttal).
[111] Ex. GP-16 at 8 (Bulkley Rebuttal).
[112] Ex. GP-14, AEB-2, Schedule 4 (Bulkley Direct).
[113] Ex. DER-1 at 32 (Addonizio Direct).
[114] DER-1 at 38-39 (Addonizio Direct).

represented a reasonable ROE for Great Plains because it was based on reasonable methodology, as discussed below.

B. Fair Rate of Return: Overall Principles

The Commission must set rates that are just and reasonable.[115] The determination of reasonableness involves a balancing of consumer and utility interests. A reasonable rate enables a public utility not only to recover operating expenses, depreciation and taxes, but also to compete for funds in capital markets (i.e., to attract sufficient capital at reasonable terms). Minnesota law recognizes this principle when it defines a "fair and reasonable" rate of return as the rate when multiplied by rate base that will give a utility a reasonable return on its total investment.[116] This means that a fair return is one that enables the utility to attract sufficient capital (induce investors) at reasonable terms.[117] However, Minnesota law requires that *any doubt* as to reasonableness should be resolved in favor of the consumer.[118] Accordingly, a ROR that provides the utility a greater return than is necessary to provide reliable service to consumers at reasonable rates would be excessive.

The *Bluefield* decision holds that a utility's return must be reasonably sufficient to assure financial soundness and provide the utility adequate means to raise capital.[119] The Supreme Court reasoned that a utility had no right to large profits similar to those realized in speculative ventures, but that the utility's return:

> [S]hould be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical

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[115] Minn. Stat. § 216B.03 (2018).
[116] Minn. Stat. § 216B.16, subd. 6 (2018).
[117] Minn. Stat. § 216B.16, subd. 6 (2018).
[118] Minn. Stat. § 216B.03 (2018) (emphasis added).
[119] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.* (Bluefield), 262 U.S. 679 (1923).

> management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[120]

Later, *Hope* reaffirmed and refined the *Bluefield* principles.[121] The *Hope* Court reiterated that utilities are only entitled to a return sufficient to cover operating expenses including services on debt and dividends on stock, assure confidence in the utility's ability to maintain credit worthiness, and attract capital. The Court added that a just and reasonable return should be similar to returns on investments in other businesses having a corresponding risk.[122]

In addition, the Court has acknowledged that regulation must attempt to strike an equitable balance between investors and ratepayers. *Covington* recognized:

> [S]tockholders are not the only persons whose rights or interests are to be considered. The rights of the public are not to be ignored. . . . The public cannot properly be subjected to unreasonable rates in order simply that stockholders may earn dividends.[123]

The *Natural Gas Pipeline Company of America* decision reemphasized this point:

> The consumer interest cannot be disregarded in determining what is a "just and reasonable" rate. Conceivably, a return to the company of the cost of service might not be "just and reasonable" to the public.[124]

Thus, utilities are only entitled to a rate of return that allows the company to attract sufficient equity investment, or otherwise obtain the financing, necessary to provide adequate and efficient service to ratepayers at just and reasonable rates.

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[120] *Bluefield*, 262 U.S. at 693.
[121] *Fed. Power Comm'n v. Hope Natural Gas Co.* (Hope), 320 U.S. 591 (1944)
[122] *Hope*, 320 U.S. at 603.
[123] *Covington and Lexington Turnpike Road Co. v. Sanford* (Covington), 164 U.S. 578, 596 (1896).
[124] *Fed. Power Comm'n v. Natural Gas Pipeline Co. of Am.*, 315 U.S. 575, 607 (1942) (Black, J., concurring).

C. Fair Rate of Return for Great Plains: An Overview

1. DER's Recommended ROE and ROR

Great Plains' cost of equity is the rate of return that it must pay to induce equity investments in its regulated operations. To estimate this cost, Mr. Addonizio used a market-oriented approach and relied on the concept of "opportunity costs."[125] The Department initially recommended an ROE of 8.875 percent for Great Plains and an overall rate of return of 6.786 percent.[126] In contrast, Great Plains requested an ROE of 10.20 percent and ROR of 7.460 percent.[127]

Mr. Addonizio's surrebuttal testimony updated the Department's initial recommendation based on more recent dividend yield and expected growth rate data for companies in the DER Proxy Group (30 trading days ending on February 12, 2020), for an updated ROE recommendation of 8.82 percent, with an overall cost of capital of 6.76 percent.[128]

2. Guidelines

To determine a fair ROE for Great Plains, the Department used the following economic guidelines, as set forth in the *Bluefield* and *Hope* cases:

- The rate of return should be sufficient to enable the regulated company to maintain its credit rating and financial integrity.
- The rate of return should be sufficient to enable the utility to attract capital at reasonable terms.
- The rate of return should be commensurate with returns being earned on other investments having equivalent risks.[129]

Investors are faced with many investment opportunities in the financial markets. To attract investors, Great Plains must pay an equity return similar to the equity return that investors

[125] DER-1 at 5 (Addonizio Direct).
[126] DER-1 at 75 (Addonizio Direct).
[127] DER-1 at 74 (Addonizio Direct).
[128] DER-9 at 80 (Addonizio Surrebuttal).
[129] DER-1 at 4 (Addonizio Direct).

expect to earn on investments of comparable risk. When investors buy the common stock of a utility, they acquire the right to share any dividends that the company may declare in the future. To induce equity investors to provide capital to Great Plains (i.e., purchase shares of equity), expected future dividends must provide a rate of return that is at least equal to the best alternative investment opportunity with a similar level of risk.[130]

The prospect of these dividends serves as an inducement to investors. Investors, however, do not know with certainty what dividends a company will pay in the future and they recognize that there is a risk that future dividends will be lower than expected. They also understand that dividends may be higher than expected.[131]

Mr. Addonizio reviewed investors' likely expectations based largely on the likely rates of return of comparable companies (DER Proxy Group), as provided by the Discounted Cash Flow (DCF) model, together with checks on the reasonableness of his results.[132] The DCF model, assuming constant growth of dividends over time, is reflected in the following formula:

> The expected (required) rate of return on equity = the expected dividend yield + the expected growth rate in dividends.

Mr. Addonizio also relied on the two-growth DCF model, which assumes that dividends grow at one rate for a short time, and then grow at a second, sustainable rate in perpetuity. While the cost of equity cannot be observed directly, with estimates of a stock's expected dividend yield (in one year) and its dividend growth rate, the cost of equity can be estimated.[133]

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[130] DER-1 at 5 (Addonizio Direct).
[131] DER-1 at 5 (Addonizio Direct).
[132] DER-1 at 5 (Addonizio Direct).
[133] DER-1 at 6-7 (Addonizio Direct).

3. The cost of common equity capital: DCF model

As noted above, a common stock investor expects to receive a flow of future dividends, but understands that there is risk associated with these future dividends. The DCF model postulates that an investor's expected future dividends as follows:

> The current price of a stock = the present value of all expected future dividends, discounted by the appropriate rate of return.[134]

The DCF model, applied to companies with comparable risk, is a reasonable market-oriented method for determining a fair ROE for Great Plains. It uses current, relevant information to determine a reasonable ROE that will provide the Company a reasonable opportunity to compete sufficiently and fairly in the capital markets.

D. DER's Recommended ROE of 8.82 Percent Is Reasonable

The Department recommended that the Commission adopt an ROE of 8.82 percent for Great Plains based on Mr. Addonizio's DCF analysis, as updated in his surrebuttal testimony.[135] The following discussion reviews Mr. Addonizio's selection of a group of companies with risks comparable to Great Plains (DER Proxy Group), his direct testimony constant growth and two-growth DCF analysis, and his surrebuttal testimony update. Additionally, this section discusses the Capital Asset Pricing Model analyses that Mr. Addonizio used to check the reasonableness of his DCF analyses.

1. DCF Proxy Group Selection

Discounted cash flow (DCF) "analysis is the most widely accepted model and one that has been used consistently as a starting point for establishing the cost of equity in public utility

[134] DER-1 at 6 (Addonizio Direct).
[135] Ex. DER-9 at 2 (Addonizio Surrebuttal).

cases before the Commission."[136] DCF analysis estimates a company's present value based on projections of how much money it will generate in the future. Great Plains cannot be analyzed directly with a DCF analysis because it is not publicly traded on any of the stock exchanges. When an entity's stock is not publicly traded, there are a few alternative ways to conduct a DCF analysis. Mr. Addonizio chose to perform a DCF analysis on a group of companies with investment risks comparable to the risks of Great Plains because it is a well-accepted financial principal that companies with similar investment risks are expected to have similar costs of equity.[137] Mr. Addonizio chose a group of companies that have business risks similar to Great Plains by applying the following screens:

- Are listed on the Compustat Research Insight data base; and
  - Have an Standard Industrial Classification code of 4924 (natural gas distribution);
  - Are traded on a stock exchange;
  - Have a Standard & Poor's ("S&P") credit ratings within the range of BBB to A+;

- Received an average of at least 60 percent of their operating income from natural gas distribution during the most recent three-years for which data is available; and

- In addition to the four companies that were listed by Compustat and met the above credit and income screens, Mr. Addonizio added one company, Southwest Gas Holdings, Inc., classified by Value Line as a natural gas company, which also met the credit rating and income requirements.[138]

Below is the Department's resulting proxy group:

[136] *In re N. States Power Co., a Minn. Corp. & Wholly Owned Subsidiary of Xcel Energy Inc., for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G-002/GR-06-1429, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 28 (2007 NSP Rate Case Order) (Sept. 10, 2007).
[137] Ex. DER-1 at 8-9 (Addonizio Direct).
[138] Ex. DER-1 at 10-12 (Addonizio Direct).

Table 1
DER Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Spire Inc.	SR
Southwest Gas Holdings, Inc.	SWX

Source: Ex. DER-1, CMA-2 (Addonizio Direct)

As part of his surrebuttal analysis, Mr. Addonizio reviewed his direct testimony screens and the fourteen companies that he originally considered for inclusion in the DER Proxy Group. Based on this review, Mr. Addonizio concluded that no additions or subtractions from the DER Proxy Group were required.[139]

Additionally, Mr. Addonizio's surrebuttal testimony responded to Great Plains witness Ms. Ann E. Bulkley's objection to South Jersey Industries, Inc.'s exclusion from the DER Proxy Group. Ms. Bulkley reasoned that Mr. Addonizio placed too much emphasis on what she described as one-time events.[140] In support of this position, Ms. Bulkley presented nine years of operating income for South Jersey Industries (SJI).[141] That data shows that in each year from 2010 through 2016, South Jersey Industries' operating income from regulated gas distribution operations was greater than 60 percent, and that in 2017 and 2018, it was less than 60 percent. As a result, Ms. Bulkley concluded that going forward in 2019 and beyond SJI will likely derive more than 60 percent of its operating income from regulated natural gas operations and is therefore a reasonable proxy for Great Plains.[142]

[139] Ex. DER-9 at 5 (Addonizio Surrebuttal).
[140] Ex. GP-16 at 19-25 (Bulkley Rebuttal).
[141] Ex. GP-16 at 22 (Bulkley Rebuttal).
[142] Ex. GP-16 at 21 (Bulkley Rebuttal).

However, Ms. Bulkley's conclusion about South Jersey Industries' future performance is highly speculative and her use of data from a decade ago provides little insight. Mr. Addonizio explained:

> [C]ompanies change their business mixes over time for a variety of reasons. A company's management may choose to initiate a new line of business or discontinue an existing line of business. Alternatively, a particular segment may grow faster over time than others within a company.[143]

Thus, as companies change, older data becomes less meaningful in an assessment of the company's future performance.[144] Additionally, South Jersey Industries' share of operating income from regulated operations has decreased even in the absence of impairments cited by Ms. Bulkley as one-time events.[145]

Given the questions surrounding South Jersey Industries, the appropriate and reasonable treatment is to exclude it from the proxy group. Including companies that may not be reasonable proxies for a target utility raises the risk of unreasonably biasing the analysis results. The more conservative approach of excluding questionable companies ensures that only appropriate companies make it into the proxy group. A proxy group assembled in this manner will be comprised only of companies that are reasonable proxies for the target utility and no bias will be introduced.[146]

2. DCF Analysis

After identifying a reasonable proxy group, Mr. Addonizio used the constant growth DCF model and the two-growth DCF model to estimate Great Plains' cost of equity. Under the DCF

143 Ex. DER-9 at 8 (Addonizio Surrebuttal).
144 Ex. DER-9 at 8 (Addonizio Surrebuttal).
145 Ex. DER-9 at 9 (Addonizio Surrebuttal).
146 Ex. DER-9 at 10 (Addonizio Surrebuttal).

methodology, cost of equity (the required rate of return) is equal to the expected dividend yield plus the expected growth rate of dividends.

a. Expected Dividend Yield

For the first DCF component, the expected dividend yield, Mr. Addonizio determined the expected dividend yield for each company in the DER Proxy Group using its current stock price, which is directly observable, and its most recent dividend, which also is directly observable. The DCF model assumes that dividends are paid once per year. The dividend yield is calculated as the expected annual dividend in the next year divided by the current stock price, and thus requires an estimate of each company's annual dividend to be paid one year from now.[147]

As to his calculation of the share price in the current period, Mr. Addonizio testified that recent prices must be used since the current price per share incorporates all relevant publicly available information. Share prices, however, can be volatile in the short run. For these reasons, it is desirable to use an average share price of a period of time long enough to avoid short-term aberrations in the capital market, but not too long in order to ensure that the measure of price used to calculate the expected dividend yield appropriately reflects all relevant publicly available information.[148] To balance these competing pressures, for purposes of calculating each company's expected dividend yield, Mr. Addonizio calculated share price as the average of the closing price over the 30 trading days ending on December 9, 2019.[149] In his surrebuttal testimony, Mr. Addonizio updated the expected dividend yield for companies in his proxy group by using the most recently available 30 trading days ending on February 12, 2020.[150]

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[147] Ex. DER-1 at 22 (Addonizio Direct).
[148] Ex. DER-1 at 23 (Addonizio Direct).
[149] Ex. DER-1 at 23 (Addonizio Direct).
[150] Ex. DER-9, CMA-S-7 (Addonizio Surrebuttal).

b. Expected Growth Rate of Dividends – Constant Growth DCF

For the second DCF component, the expected dividend growth rate for each company in the DER Proxy Group, Mr. Addonizio relied on the expected earnings growth rates provided by three respected and widely-used investment research services, Zacks Investment Research (Zacks), Value Line, and Thomson First Call (Thomson). Specifically, he used the three projected earnings growth rates (lowest, average and highest) provided by Zacks, Value Line, and Thomson.[151] Further, and consistent with financial studies and literature, Mr. Addonizio used projected earnings per share growth rates, rather than dividend per share or book value per share, since the long-run sustainable growth in dividends is solely driven from earnings growth.[152]

As part of this process, Mr. Addonizio also performed a high-level review of all the projected earnings growth rates to identify any unreasonably high or low values.[153] By performing this review for all of his inputs, Mr. Addonizio avoided the subjectivity concerns raised in Ms. Bulkley's rebuttal testimony.[154]

Only one growth rate was identified as unreasonable: Value Line's 27.0 percent five-year growth rate for Northwest Natural Holding Company ("NWN" in Figure 5). In contrast to Value Line's Northwest Natural growth rate, none of the other growth rates appeared so obviously different from the others as to merit any additional scrutiny:

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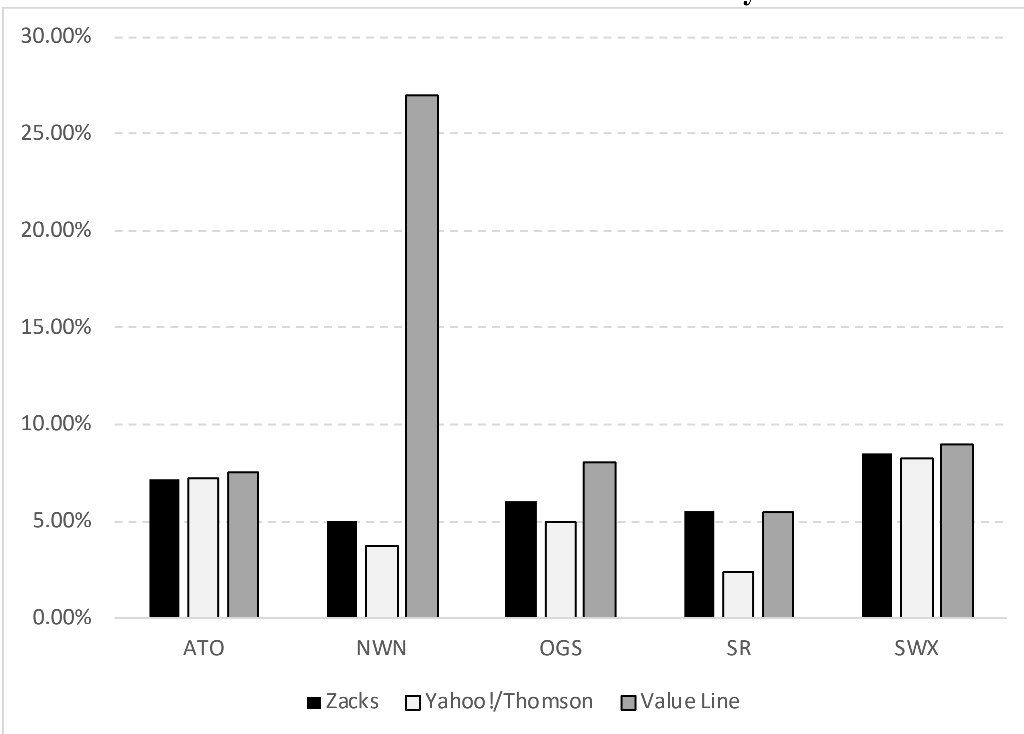
[151] Ex. DER-1 at 14 (Addonizio Direct).
[152] Ex. DER-1 at 15-16 (Addonizio Direct).
[153] Ex. DER-9 at 30 (Addonizio Surrebuttal).
[154] Ex. GP-16 at 39-40 (Bulkley Rebuttal).

Figure 5
Growth Rate Estimates for the DER Proxy Group in Mr. Addonizio's Direct Testimony[155]



Mr. Addonizio concluded that Value Line's 27.0 percent growth rate was unreasonable because it was more than five times higher than the other two estimates for Northwest Natural and three times higher than the next highest single estimate for any of the other proxy companies.[156] Upon further investigation, Mr. Addonizio determined that Value Line's 27.0 percent growth rate for Northwest Natural was caused by a $192.5 million one-time impairment charge that is not representative of actual growth or dividend payments to shareholders.[157]

As an alternative to excluding Value Line's 27.0 percent growth rate and using the mean of the ROE results for each of the proxy companies, Ms. Bulkley argued that Mr. Addonizio should have included Northwest Natural's growth rate and used the median of his ROE

[155] Ex. DER-9 at 31 (Addonizio Surrebuttal).
[156] Ex. DER-9 at 31 (Addonizio Surrebuttal).
[157] Ex. DER-1 at 17-21 (Addonizio Direct).

results.[158] Ms. Bulkley's alternative, however, selectively and inconsistently applies the median in a way that allows Value Line's 27.0 percent growth rate to unreasonably affect ROE calculations.[159]

While Ms. Bulkley used the median as a measure-of-center of the ROE estimates produced for each of the companies in the proxy group, she still used the mean of each company's estimated growth rates to develop each company's individual ROE estimate. As a result, Northwest Natural's mean ROE estimate is still a function of Value Line's unreasonable 27.0 percent growth estimate, which produces an ROE estimate of 14.38 percent, which is 350 to 730 basis points higher than the other ROE estimates.[160]

An approach that would be more consistent with Ms. Bulkley's stated goal of mitigating the impact of outliers would be to use the median of each company's three estimated growth rates, rather than the mean, to develop a median ROE estimate for each company. Then, the median could also be used as a measure-of-center of those median ROE estimates to determine a final result.[161]

Additionally, Ms. Bulkley's rebuttal testimony argued that Mr. Addonizio should have excluded Spire Inc.'s 2.37 percent earnings growth rate from Yahoo! ("SR" in Figure 5) as unreasonably low.[162] In response, Mr. Addonizio's surrebuttal testimony first explained that the magnitude of the year-to-year changes in Spire's earnings was significantly smaller than the year-to-year changes that impacted Value Line's calculation of NWN's growth rate.[163]

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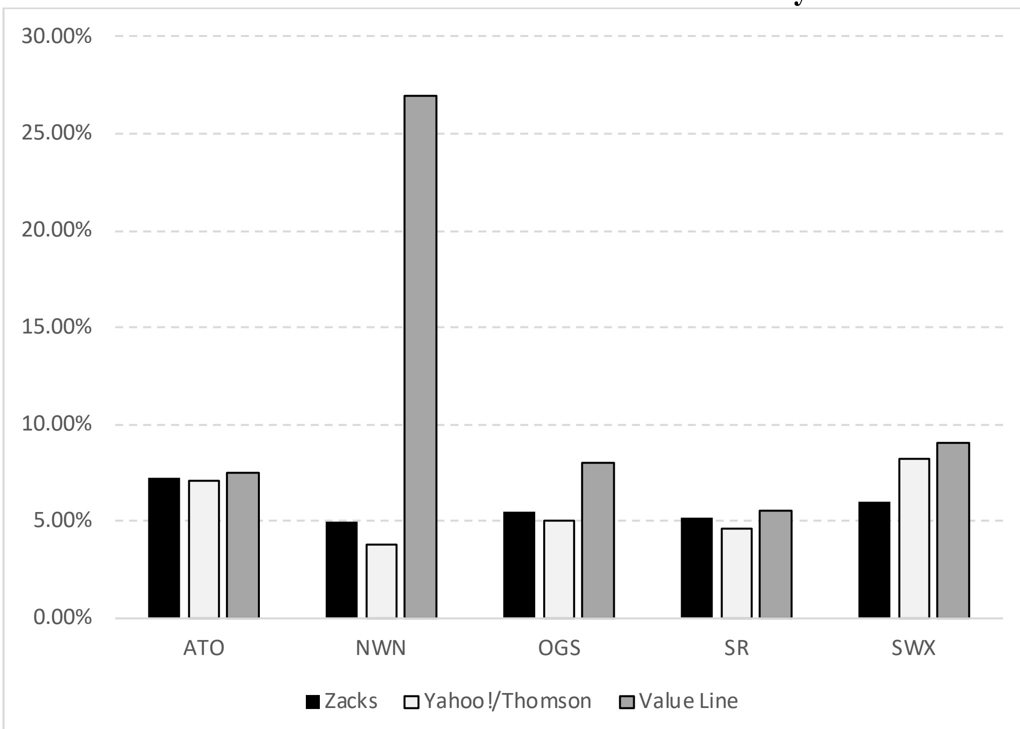
[158] Ex. GP-16 at 35 (Bulkley Rebuttal).
[159] Ex. DER-9 at 36-37 (Addonizio Surrebuttal).
[160] Ex. DER-9 at 37 (Addonizio Surrebuttal).
[161] Ex. DER-9 at 37 (Addonizio Surrebuttal).
[162] Ex. GP-16 at 34 (Bulkley Rebuttal).
[163] Ex. DER-9 at 33 (Addonizio Surrebuttal).

Mr. Addonizio second explained that Ms. Bulkley's concern was mooted by updated financial information that resulted in an upwards adjustment to Spire Inc.'s estimated growth rate:

Figure 7
Growth Rate Estimates for the DER Proxy Group in Mr. Addonizio's Surrebuttal Testimony[164]



c. Expected Growth Rate of Dividends – Two-Growth DCF

Mr. Addonizio performed a second set of DCF analyses that used two-growth rates for each company. The two-growth DCF uses one growth rate for the first five years, and then a second, sustainable growth rate for year six and beyond. The two-growth DCF model accounts for situations where the short-term projected earnings growth rates may not be expected to continue in the long run because the short-term rate may be unusually low or unusually high, relative to the company's historical averages, industry averages, or relative to the economy as a

[164] Ex. DER-9 at 35 (Addonizio Surrebuttal).

whole.[165] Unusually low or high growth rates may result in unreasonably low or high estimates of the cost of equity. Mr. Addonizio, for the short-term growth rate, used the five-year projected earnings growth rates that he used in the constant growth DCF analysis from Zacks, Value Line, and Thomson.[166]

For the long-term growth rates, Mr. Addonizo first determined the likelihood for each company in the DER Proxy Group that its five-year project growth rate is sustainable. Growth rates may be considered unsustainable if they are unusually low or unusually high relative to the industry. To make this assessment, Mr. Addonizio calculated the average growth rate for the DER Proxy Group and the standard deviation of the growth estimates. He determined that any growth rate that was lower than one standard deviation below the proxy group's average may not be sustainable and, similarly, any growth rate that is higher than one standard deviation above the proxy group's average growth rate may not be sustainable.[167]

As part of his two-growth DCF analyses, Mr. Addonizio again performed a high-level review of his inputs. While the two-growth DCF model is intended to mitigate the effect of unsustainable growth rates, it is not robust against extreme outliers. In this instance, including Value Line's 27.0 percent growth estimate would have unreasonably inflated the group's average and its standard deviation, resulting in a much higher and much wider range of ROE's considered to be sustainable.[168] Mr. Addonizio found that inclusion of Value Line's 27.0 percent

[165] Ex. DER-1 at 24 (Addonizio Direct).
[166] Ex. DER-1 at 26 (Addonizio Direct).
[167] Ex. DER-1 at 26-27 (Addonizio Direct).
[168] Ex. DER-1 at 28 (Addonizio Direct).

growth estimate would have dramatically increased the recommended ROE for Great Plains from 8.82 percent to 10.26 percent, before adjusting for flotation costs.[169]

Based on this analysis, Mr. Addonizio's Table 5 from his direct testimony shows results from his two-growth DCF analyses for the DER Proxy Group:

Table 5
Summary of Two-Growth DCF Results[170]

	Mean Low ROE	Mean Avg. ROE	Mean High ROE
DER Proxy Group Average	7.99%	8.82%	9.70%

Ex. DER-1, CMA-4 through CMA-6 (Addonizio Direct)

Ms. Bulkley's rebuttal testimony objected to the Department's reliance on two-growth DCF analyses despite its theoretical soundness and the Commission's previously expressed preference for it.[171] Ms. Bulkley instead argued that DCF analyses are not reliable because investors are irrational and have been overreacting to certain market information for several years.[172] As a result, she asserted, markets are not efficient in the sense that current market prices and conditions do not reflect investors' expectations regarding future market conditions. Ms. Bulkley concluded that market-based estimates of current required ROEs cannot be relied upon to determine required ROEs without some sort of adjustment based on forecasted market performance.[173]

Ms. Bulkley's assessment is unreasonable because it is contrary to basic financial theory, and lacks adequate academic and market data support. First, it is not reasonable to assume that

[169] Ex. DER-1 at 28 (Addonizio Direct).
[170] Ex. DER-1 at 27 (Addonizio Direct).
[171] *See, e.g.*, 2007 NSP Rate Case Order at 28.
[172] Ex. GP-16 at 44 (Bulkley Rebuttal).
[173] Ex. GP-16 at 45 (Bulkley Rebuttal).

investors would hold assets that they expect to decrease significantly in value in the near future.[174] If investors expected utility stock prices to decrease in the near future as Ms. Bulkley implied, they would not continue to hold those assets and simply accept the losses. Rather, investors would sell those assets immediately to lock in the gains. By selling, investors would immediately drive down the price of utility stocks to a level at which they accurately reflect investors' expectations about the future and their current attitudes regarding risk. In this way, current stock prices fully reflect all currently available information, as well as investors' expectations for the future based on their assessments of that information.[175]

Second, Ms. Bulkley only relies on a small number of reports that reflect a small subset of opinions regarding current and future market conditions to make this expansive claim.[176] Third, if Ms. Bulkley is correct in her assertions that investors are irrational, markets are inefficient, and current market conditions do not reflect investor expectations regarding future market conditions, then there is no reason to expect that future market conditions will accurately reflect investor expectations, either.[177]

d. Updated DCF Analyses

As part of his surrebuttal analysis, Mr. Addonizio updated the stock prices he used when calculating dividend yields and the dividend amounts for companies that changed their dividends. Mr. Addonizio also updated the growth estimates for some of the companies in the DER Proxy Group based on new Zacks Investment Research and Thomson First Call data.

[174] Ex. DER-9 at 39 (Addonizio Surrebuttal).
[175] Ex. DER-9 at 39 (Addonizio Surrebuttal).
[176] *See generally* Ex. GP-14 at 16-40 (Bulkley Direct).
[177] Ex. DER-9 at 40 (Addonizio Surrebuttal).

Mr. Addonizio further noted that Value Line did not release new information in the period between his direct and surrebuttal analyses.[178]

Based on this updated information, Mr. Addonizio's Table 2 from his surrebuttal testimony shows his final DCF analysis for the DER Proxy Group:

Table 2
Summary of DCF Results
Adjusted for Flotation Costs[179]

Model	Mean Low ROE	Mean Avg. ROE	Mean High ROE
Constant Growth DCF	7.95%	8.79%	9.67%
Two-Growth DCF	7.90%	8.82%	9.67%

Ex. DER-9, CMA-S-2 through CMA-S-5 (Addonizio Surrebuttal)

e. Comparable Return Standard

In addition to her other DCF criticisms, Ms. Bulkley's rebuttal testimony concludes, "Mr. Addonizio's recommendation does not meet the comparable return standard outlined in the *Hope* and *Bluefield* decisions[.]"[180] Ms. Bulkley reasoned, in part, that Mr. Addonizio's recommendation was inadequate because it was lower than the ROEs approved for some other natural gas utilities in the United States.[181]

Despite Ms. Bulkley's conclusions, neither *Hope* nor *Bluefield* guarantee a utility a rate of return equal or greater to those approved for other gas distributions utilities at other times by other regulatory agencies in other states.[182] Rather, the reasonable ROE for any particular utility

[178] Ex. DER-9 at 3-4 (Addonizio Surrebuttal).
[179] Ex. DER-9 at 3-4 (Addonizio Surrebuttal).
[180] Ex. GP-16 at 15-16 (Bulkley Rebuttal).
[181] Ex. GP-16 at 11-12 (Bulkley Rebuttal).
[182] Ex. GP-16 at 12 (Bulkley Rebuttal).

must be based on its specific risk profile and the market conditions existing at the time of its rate case. *Hope* states:

> Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid[.][183]

Bluefield further explains:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties[.][184]

Hope and *Bluefield* ask the Commission only to identify a reasonable ROE for Great Plains based its unique circumstances. They do not require consideration of any specific factors or require an ROE based on what has been approved for another utility.

Moreover, authorized ROE is often not a good indicator of the return an investment in a utility's equity offers to investors because the price of a utility's equity (i.e., its stock price) adjusts such that its expected return is equal to investor demand and not the company's regulator-authorized ROE. Authorized ROEs may deviate from required returns on equity for a variety of reasons.

First, market conditions and investor attitudes towards risk change over time. Even if a utility's authorized ROE was set exactly equal to the required ROE demanded by equity investors at the time the authorized ROE was set, if market conditions (e.g., interest rates) or investors' level of risk-tolerance have changed, then the authorized ROE will no longer be equal

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[183] *Fed. Power Comm'n, vs. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944).
[184] *Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692–93 (1923).

to investors' required ROE.[185] For this reason, ROEs authorized even just a few months ago should be viewed with caution. ROEs authorized farther in the past should be ignored altogether because they cannot be assumed to still accurately reflect investors' required return on equity. Figure 3 of Ms. Bulkley's rebuttal testimony compares Mr. Addonizio's direct testimony ROE recommendation to authorized ROEs for natural gas utilities as far back as January 1, 2009.[186] However, most of those data points have no relevance to this proceeding because they are too old to be considered reliable estimates of the current required ROE.[187] As a result, authorized ROEs for other gas distribution utilities are at best only very indirect measures of the returns available to potential investors, and at worst are largely irrelevant.[188] Accordingly, it is better to rely on market-based estimates of the returns available to a utility's equity investors, such as those produced by the DCF model or the CAPM.[189]

Second, state commissions sometimes account for other factors when determining a utility's authorized ROE that are not applicable to other utilities. For example, Ms. Bulkley's rebuttal testimony referred to the Commission's decision in Otter Tail Power Company's most recent rate case.[190] However, she failed to mention that the Commission based its decision in part on Otter Tail's history of completing major infrastructure projects under budget and its high customer satisfaction ranking among mid-size utilities.[191] While Otter Tail is an electric utility,

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[185] Ex. DER-9 at 70 (Addonizio Surrebuttal).
[186] Ex. GP-16 at 12 (Bulkley Rebuttal).
[187] Ex. DER-9 at 70-71 (Addonizio Surrebuttal).
[188] Ex. DER-9 at 69 (Addonizio Surrebuttal).
[189] Ex. DER-9 at 70 (Addonizio Surrebuttal).
[190] Ex. GP-16 at 47, 63, 70-71 (Bulkley Rebuttal).
[191] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*. MPUC Docket No. E-017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 55 (May 1, 2017) ("The Commission has . . . considered Otter Tail's recognized . . . performance in completing major infrastructure projects substantially
(Footnote Continued on Next Page)

and its specific authorized ROE has no relevance to this proceeding, this example is indicative of why other utilities' authorized ROE's should be given little to no weight in determining Great Plains' authorized ROE.[192]

For these reasons, Mr. Addonizio's decision to rely on discounted cash flow analyses, while using CAPM analyses as check, to recommend an ROE for Great Plains was reasonable.

3. Flotation Costs

The Department agrees with Great Plains that ROE estimates derived using DCF analyses must be adjusted for flotation costs. Flotation costs are the costs of issuing new shares of common stock. Due to issuance costs, the price paid by an investor for a new share is higher than the price received by the company issuing the new share. As a result, the company must earn a higher percentage return on its stock issuance proceeds than investors require on their investments in order to meet investor's required rate of return.[193] However, not all equity issuances incur flotation costs. For example, shares issued through employee compensation programs and dividend reinvestment programs often do not incur flotation costs.[194]

Accordingly, Mr. Addonizio reviewed the Company's flotation cost calculations. Great Plains provided an estimate of the flotation cost percentage on equity issued through underwriters based on two equity issuances by MDU Resources, but it did not account for equity issued through processes that did not incur flotation costs. The Company estimated that its flotation costs for equity issuances that incurred flotation costs is 3.68 percent. However, this

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(Footnote Continued from Previous Page)
under budget, its history of providing reliable service with stable rates, and its record of effectively serving the needs of its customers, as measured by multiple customer-satisfaction metrics.").

[192] Ex. DER-9 at 71 (Addonizio Surrebuttal).

[193] Ex. DER-1 at 29 (Addonizio Direct).

[194] Ex. DER-1 at 31 (Addonizio Direct).

number is likely inflated because it does not account for equity issuances that did not incur flotation costs.[195] Mr. Addonizio adjusted Great Plains' estimated flotation costs of 3.68 percent to account for this inflation by conservatively assuming that half of Great Plains' equity was obtained by means that did not incur flotation costs. Mr. Addonizio reasoned this adjustment allows the Company to recover some flotation costs while reducing the risk of over or double recovery.

In her rebuttal testimony, Ms. Bulkley acknowledged that equity issuances via means other than public issuances are less expensive.[196] She also failed to document MDU Resources Group's actual expenses relating to non-public equity issuances. Ms. Bulkley stated only that MDU Resources Group paid the costs of investing employee dividends.[197] Given Great Plains' inability or unwillingness to provide any meaningful information regarding the flotation costs it has incurred on equity issuances via means other than public offerings, Ms. Bulkley's recommended flotation cost adjustment is unsupported. Ms. Bulkley's recommended flotation cost adjustment also is likely overstated given her acknowledgment that other sources of equity are usually less expensive. It is unreasonable to allow the Company to recover fully costs that it cannot meaningfully estimate.[198]

Based on his review, Mr. Addonizio recommended that flotation costs be set at 1.84 percent.[199] This recommendation allows Great Plains to recover some flotation costs, which it

[195] Ex. DER-1 at 31 (Addonizio Direct).
[196] Ex. GP-16 at 67 (Bulkley Rebuttal); DER-9 at 64 (Addonizio Surrebuttal).
[197] Ex. GP-16 at 66-68 (Bulkley Rebuttal).
[198] Ex. DER-9 at 64 (Addonizio Surrebuttal).
[199] Ex. DER-1 at 32 (Addonizio Direct).

has undoubtedly incurred, while also placing a reasonable limit on its recovery of those costs in response to its lack of support for those costs.[200]

4. Capital Asset Price Modeling

Mr. Addonizio checked the reasonableness of his constant growth DCF and two-growth DCF analyses by using the Capital Asset Pricing Model (CAPM). CAPM's basic premise is that any company-specific risk can be diversified away by investors. Therefore, the only risk that matters is the stock's systematic risk, which is measured by beta (market risk premium). The required rate of return on the stock is calculated as the sum of the stock's beta multiplied by the market risk premium, and the rate of return on a riskless asset.[201] While CAPM is theoretically sound, its use raises some difficult issues, including challenges determining the appropriate beta, the appropriate riskless asset, and the appropriate estimate of the required return on the market portfolio. For these reasons, the Department used CAPM results only as a check on the reasonableness of its DCF analyses.[202] Additionally, the Commission has, in past dockets, expressed a clear preference for DCF analyses.[203]

a. Rate of Return for a Riskless Asset (r_f)

The first input into the CAPM formula ($k = r_f + \text{beta}\ (k_m - r_f)$) is the rate of return on a riskless asset (r_f). A 30-year U.S. Treasury bond generally is considered to be devoid of default risk. It also better matches the equity investor's stock holding period (as opposed to a 90-day bond). However, investing in a 30-year treasury bond would subject an investor to investment

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200 Ex. DER-9 at 65 (Addonizio Surrebuttal).
201 Ex. DER-1 at 33-34 (Addonizio Direct).
202 Ex. DER-1 at 34-35 (Addonizio Direct).
203 *See, e.g.*, *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*, MPUC Docket No. G008/GR-15-424 (CenterPoint 2016 Rate Case), FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 38 (June 3, 2016).

risk associated with foregone investment opportunities because his or her cash is tied up in previously made investments.[204] As a compromise between the risks associated with short-term and long-term treasuries, Mr. Addonizio used the yield on 20-year U.S. Treasury bonds as the risk-free rate. Additionally, he used the average yield over the 30 trading days to eliminate any bias that may be introduced from day-to-day volatility.[205]

In rebuttal testimony, Ms. Bulkley disagreed with Mr. Addonizio's use of yields on 20-year U.S. Treasury bonds as a proxy for the risk-free rate. She also disagreed with his use of current yields rather than forecasted yields.[206] While the Department believes that use of yields on 20-year U.S. Treasury Bonds better balances investor timelines and forgone investment risk, Mr. Addonizio noted that the use of 30-year U.S. Treasury Bonds only increased his CAPM analysis results by six basis points.[207]

However, Ms. Bulkley's argument that forecasted bond yields should be used in CAPM analyses is unreasonable. Bond prices and yields are subject to the same types of market forces as stock prices.[208] If investors expect a bond's interest rates to rise and its price to fall, they will not simply hold the bond and accept the losses. They will try to sell the bond before the price falls to avoid the losses – driving the price of the bond down and the yield up. Similarly, if investors expect a bond's price to rise, they will not simply watch from the sidelines, they will try to buy before the price rises in order to capture the gain, driving the price up and the yield down. Thus, bond prices and yields reflect current investor expectations, and will only change as new, unpredictable, information causes investor expectations to change. Because future

[204] Ex. DER-1 at 35 (Addonizio Direct).
[205] Ex. DER-1 at 36 (Addonizio Direct).
[206] Ex. GP-16 at 50 (Bulkley Rebuttal).
[207] Ex. DER-9 at 41 (Addonizio Surrebuttal).
[208] Ex. DER-1 at 56 (Addonizio Direct).

information is unpredictable, its impact on interest rates also is unpredictable.[209] For this reason, current interest rates are the best predictor of future interest rates, and Ms. Bulkley's use of forecasted interest rates is unreasonable.

In support of her argument, Ms. Bulkley misrepresented the holding of an article published by the San Francisco Federal Reserve to suggest that the Blue Chip forecasting model she employed is at least as accurate as the No-Change method used by Mr. Addonizio. In fact, the article suggests that existing approaches to forecasting interest rates are generally worse than a simple assumption that interest rates will not change from their current levels. The article also includes a chart that directly compares the forecast error associated with forecasts of yields on 10-year U.S. Treasuries produced by the No-Change method that Mr. Addonizio used and the Blue Chip forecasts that Ms. Bulkley used.[210]

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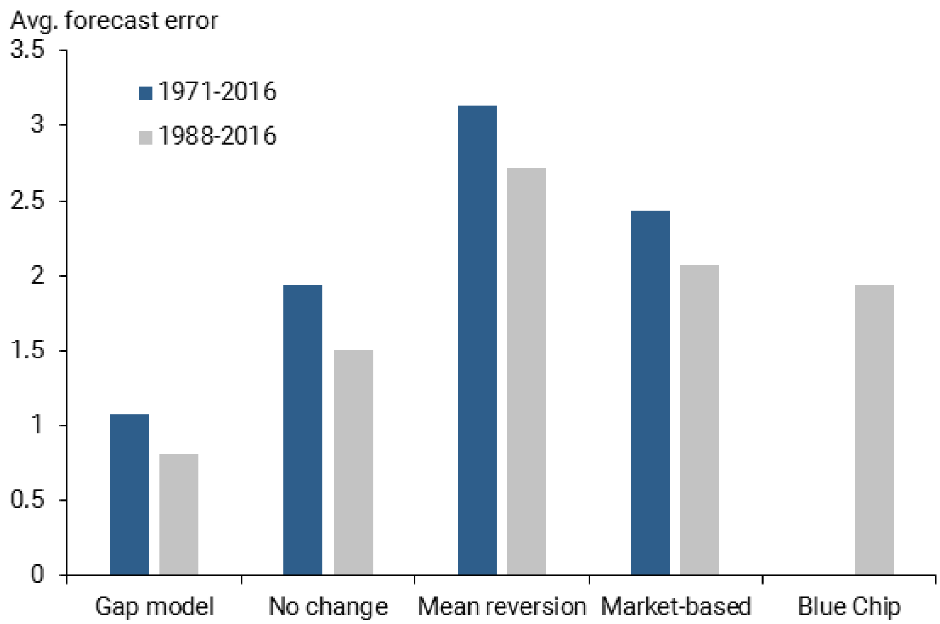
[209] Ex. DER-9 at 42-43 (Addonizio Surrebuttal).
[210] Ex. DER-9 at 43-44 (Addonizio Surrebuttal).

Figure 8
Forecast Accuracy of 10-Year Yield Estimates, 5 Years Ahead[211]



Ms. Bulkley reached her conclusion by comparing the forecast error of the No-Change and the Blue Chip forecasts for different time periods: the No-Change method between 1971-2016 with the forecast error for Blue Chip between 1988-2016.[212] This comparison is unreasonable. As Figure 8 (a reproduction from the article) shows, the error rate for every forecast method is larger over a longer time period. However, when the Blue Chip and No-Change methods are compared over the same time period, the No-Change method employed by Mr. Addonizio was found to be more accurate by the San Francisco Federal Reserve article cited by Ms. Bulkley. Thus, the article supports Mr. Addonizio's position that the No-Change method produces superior forecasts in comparison to Ms. Bulkley's Blue Chip method.[213]

[211] Ex. DER-9 at 45 (Addonizio Surrebuttal); Ex. DER-9, CMA-S-26 at 4 (Addonizio Surrebuttal).
[212] Ex. GP-16 at 53, n.65 (Bulkley Rebuttal); Ex. DER-9 at 45 (Addonizio Surrebuttal).
[213] Ex. DER-9 at 46 (Addonizio Surrebuttal).

Next, Ms. Bulkley argued that Mr. Addonizio's position that forecasted Treasury bond yields is inconsistent with his use of forecasted data in his DCF analyses. Ms. Bulkley's criticism is unfounded because she is attempting to compare two fundamentally different types of analysis. It is not reasonable to draw this comparison because bond yields are directly observable, while Great Plains' ROE is not directly observable and must be estimated using financial models such as the DCF or the CAPM.[214]

If the reasonable ROE for a regulated utility was directly observable, like a stock price or a bond yield, direct observations could be used to determine an ROE for Great Plains. Establishing a reasonable ROE, however, cannot be done through direct observation. The best methods of estimating ROE involves the use of forecasted earnings growth rates.[215] There is no better alternative. There is, however, a better alternative to forecasted interest rates: current interest rates. Ms. Bulkley's attempt to equate the use of forecasted earnings growth rates to estimate ROE with the use of forecasted interest rates to measure interest rates is unreasonable.[216]

b. Market Rate of Return (k_m)

The second input into the CAPM formula ($k = r_f + \text{beta } (k_m - r_f)$) is the market rate of return (k_m). To determine the market rate of return, it is necessary to select a market portfolio. Once a market portfolio is selected, the required return on that portfolio can be estimated. In this case, Mr. Addonizio used the S&P 500, a common choice for CAPM analyses, as a proxy for the market portfolio. State Street Global Advisors manages an exchange-traded fund (ETF) designed to mimic the S&P 500 Index, and reports an estimated 3-5 year earnings growth rate for

[214] Ex. DER-9 at 48-49 (Addonizio Surrebuttal); Ex. DER-1 at 7 (Addonizio Direct); Ex. GP-14 at 43 (Bulkley Direct)
[215] Ex. DER-1 at 15-16 (Addonizio Direct).
[216] Ex. DER-9 at 49 (Addonizio Surrebuttal).

the holdings of the ETF that it calculates using equity analysts' earnings estimates for the companies included in the ETF.[217] Mr. Addonizio used this earnings growth estimate as the estimate of the growth rate for the market portfolio, which was 10.75 percent as of January 1, 2020.

The CAPM also requires a dividend yield. The dividend yield for the S&P 500 as of January 1, 2020, was 1.77 percent. Similar to the dividend yields used in his DCF analysis, Mr. Addonizio applied a half years' worth of growth to this dividend yield, resulting in a dividend yield of 1.87 percent. Thus, the required rate of return on the S&P 500 is 1.87 percent + 10.73 percent = 12.62 percent. Mr. Addonizio used this return as the market rate of return (k_m).[218]

In rebuttal testimony, Ms. Bulkley expressed concern that the projected earnings growth for the assets underlying the ETF used by Mr. Addonizio may somehow be different than the projected earnings growth rate for the S&P 500 due to technical issues and tracking error. This concern is unwarranted.

The State Street document cited by Mr. Addonizio reports separate projected earnings growth rates for the holding of the ETF and the S&P 500 Index itself.[219] As Mr. Addonizio explained in his surrebuttal testimony, he relied on the projected earnings growth rate for the S&P 500 Index in his CAPM analysis not the ETF's projected growth rate.[220] Further, at the time Mr. Addonizio prepared the analyses in his direct and surrebuttal testimonies, the projected earnings growth rates for the ETF and the S&P 500 Index were identical. Thus, even if

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[217] Ex. DER-1 at 36-37 (Addonizio Direct).
[218] Ex. DER-1 at 37 (Addonizio Direct).
[219] Ex. DER-1, CMA-14 (Addonizio Direct).
[220] Ex. DER-9 at 53-54 (Addonizio Surrebuttal).

Mr. Addonizio had used the expected EPS growth rate for the ETF instead of the rate for the S&P 500 Index, as Ms. Bulkley suggested, there would have been no tracking error.

In rebuttal testimony, Ms. Bulkley next objected to Mr. Addonizio's use of State Street "for an ETF as opposed to the earnings growth rate published by S&P for the actual S&P Index."[221] In surrebuttal testimony, Mr. Addonizio explained that S&P's earnings growth rate is likely calculated as a weighted average of the earnings growth rates of the individual stocks included in the S&P 500 Index. He further explained that the sources of the growth rates included in S&P's model are not known. In contrast, State Street sources its growth rates for the individual stocks in the S&P 500 Index from several well-respected investor services, including FactSet, First Call, I/B/E/S Consensus, and Reuters.[222] Finally, Mr. Addonizio noted that S&P's S&P 500 Index earnings growth estimate as of February 13, 2020 is 11 basis points lower than State Street's earnings growth estimate.[223] Accordingly, Ms. Bulkley's argument in favor of the S&P's S&P 500 Index is largely moot and may support the Department's position of a lower ROE for Great Plains.

c. Beta Estimate

The third input into the CAPM formula ($k = r_f + \text{beta}\ (k_m - r_f)$) is the estimated beta for the target company. Mr. Addonizio used estimates of beta for each of the companies in the DER Proxy Group provided by Value Line. An average of these betas produced a beta figure of 0.64 for Great Plains.[224]

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[221] Ex. GP-16 at 58 (Bulkley Rebuttal).
[222] Ex. DER-9 at 55-56 (Addonizio Surrebuttal); Ex. DER-9, CMA-S-28 (Addonizio Surrebuttal).
[223] Ex. DER-9 at 56 (Addonizio Surrebuttal).
[224] Ex. DER-1 at 37 (Addonizio Direct).

Ms. Bulkley's rebuttal testimony objected to Mr. Addonizio's use of Value Line betas. She asserted that Value Line's betas, which are calculated using five years of data, do not appropriately account for the Tax Cuts and Jobs Act's (TCJA) impact on utilities' stock performance relative to the S&P 500 Index. Ms. Bulkley also asserted the TCJA's effect was temporary. As a result, she argued, Value Line's betas are artificially low, and therefore produce artificially low CAPM results.[225]

However, Ms. Bulkley's claim that the impact of the TCJA was temporary, and her implicit assertion that the relationship between utility stock performance and the performance of the S&P 500 has since returned to normal, is not supported by her data.[226] Since at least 2015, the correlation between the two indices has remained depressed and has not trended back towards its 20-year value:

Figure 10
Relationship Between S&P Utilities Index and S&P 500 Index[227]

Time Period	Correlation	Relative Volatility
20-Year Value	0.55	1.03
5-Year Value	0.31	1.03
4-Year Value	0.29	0.97
3-Year Value	0.31	0.91
2-Year Value	0.35	0.82
1.5-Year Value	0.39	0.76
1-Year Value	0.27	0.85
0.5-Year Value	0.05	0.97

[225] Ex. GP-16 at 54-57 (Bulkley Rebuttal).
[226] Ex. DER-9 at 50-51 (Addonizio Surrebuttal).
[227] Ex. DER-9 at 51 (Addonizio Surrebuttal).

As shown in Figure 10 above, the decrease in correlation that Ms. Bulkley claimed is temporary has persisted for several years.[228] For that reason, it is reasonable to conclude that utility betas have declined as well, contrary to Ms. Bulkley's conclusion, and Value Line's estimates may be more representative of current market conditions.

d. Overall CAPM Estimate

With the above inputs, Mr. Addonizio's CAPM analysis estimated that Great Plains' required ROE is 8.90 percent, including a flotation cost adjustment of five basis points.[229]

e. Updated CAPM Estimate

As part of his surrebuttal analysis, Mr. Addonizio updated his CAPM analyses with more current estimates of the risk-free rate and the rate of return on the market portfolio.[230] With this more current data, Mr. Addonizio re-ran his CAPM analyses using the process described above. With these updated data, Mr. Addonizio's CAPM analysis resulted in an estimated required rate of return on equity of 9.38 percent.[231] This result falls within the ROE range Mr. Addonizio developed with his DCF analysis. Thus, this updated CAPM analysis again confirmed the reasonableness of Mr. Addonizio's DCF-derived recommendation.[232]

5. Final Department Recommended ROE

For the reasons discussed above, the Department's final (updated) recommended ROE of 8.82 percent for Great Plains is reasonable.

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[228] Ex. DER-9 at 52 (Addonizio Surrebuttal).
[229] Ex. DER-1 at 37 (Addonizio Direct).
[230] Ex. DER-9 at 4-5 (Addonizio Surrebuttal).
[231] Ex. DER-9, CMA-S-8 (Addonizio Surrebuttal).
[232] Ex. DER-9 at 5 (Addonizio Surrebuttal).

E. Ms. Bulkley's DCF and Other Analyses are Unreasonable

This section explains why Mr. Addonizio reasonably concluded that the analyses and recommendation of Great Plains witness Ms. Bulkley would not result in a reasonable ROE for the Company.

1. Ms. Bulkley's DCF Analyses

a. Ms. Bulkley's Proxy Group Screening was Unreasonable

Like Mr. Addonizio, Ms. Bulkley developed a proxy group for her DCF analyses.[233] In its review, the Department identified two problems with Ms. Bulkley's proxy group screening process.

First, Ms. Bulkley allowed operating losses in non-regulated operating segments to make income from regulated operating segments appear disproportionately large.[234] Mr. Addonizio provided the following example:

> Assume a hypothetical company has two operating segments: regulated gas distribution and widget production. Then, also assume that in 2019, the regulated gas distribution segment generated an operating income of $100, and the widget segment generated an operating income of $60, for company total of $160 of operating income. In that scenario, the calculation of the percentage of operating income derived from regulated gas distribution operations is straightforward. It is simply $100/$160 = 62.5 percent.
>
> However, now assume that in 2019 the regulated gas distribution segment generated an operating income of $100, but the widget segment generated an operating loss of $99, for company total of only $1 of operating income. Using the same straightforward calculation as above would calculate the percentage of operating income from regulated gas operations as $100/$1 = 10,000 percent.[235]

This distortion is effectively how Ms. Bulkley treated segment losses in her screening calculations, except that where the percentage of income was greater than 100 percent, she

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[233] Ex. GP-14 at 42 (Bulkley Direct).
[234] Ex. DER-1 at 45-46 (Addonizio Direct).
[235] Ex. DER-1 at 45-46 (Addonizio Direct).

capped her reported percentages at 100. In the second example, the company's investors are exposed equally to regulated gas distribution and widget making risks because the gas distribution and widget segments contribute equally to the company's operating income. As a result, the company would not be a good proxy for Great Plains, but the company would pass Ms. Bulkley's operating income screen.[236]

As an alternative, the Department recommended that Great Plains use the absolute values of each segment's operating income or loss to calculate the total company amount, as well as the percentages attributable to each segment.[237] Applying this adjustment, the Department recommended exclusion of two companies that Ms. Bulkley included in her proxy group: South Jersey Industries, Inc. and NiSource, Inc.[238]

Ms. Bulkley's rebuttal testimony responded to the Department's recommendation that South Jersey Industries and NiSource be excluded. As discussed above, Ms. Bulkley argued that it was inappropriate to exclude South Jersey Industries from the proxy group because, in her view, the company would likely exceed the 60 percent income threshold requirement in the future and the impairments that reduced its regulated income were one-time events.[239] Regarding NiSource, Ms. Bulkley concluded that the explosion that caused NiSource's operating income from regulated gas operations to fall below 60 percent threshold was a one-time event and that its stock price is no longer affected by the accident.[240] However, as Mr. Addonizio testified, explosion related lawsuits, insurance claims, and regulatory investigations are ongoing. Until these matters are fully resolved, the full financial impact of the explosion is unknown.

[236] Ex. DER-1 at 46-47 (Addonizio Direct).
[237] Ex. DER-1 at 47 (Addonizio Direct); Ex. GP-14 at 43 (Bulkley Direct).
[238] Ex. DER-1 at 47 (Addonizio Direct).
[239] DER Initial Brief at IV(5)(D)(1).
[240] Ex. GP-16 at 22-25 (Bulkley Rebuttal).

Accordingly, investors cannot yet incorporate these unresolved issues into their investment decisions.[241]

Regardless of the explosion, Mr. Addonizio ultimately recommended NiSource be excluded because it failed the 60 percent operating income threshold requirement for the most recent three-year period for which data is available. Mr. Addonizio noted that NiSource's percentage of operating income derived from regulated gas operations has been below the 60 percent threshold three times, between 60.0 and 62.0 percent three times, and no higher than 66.1 percent in the remaining three years.[242] Thus, even under the best circumstances, NiSource has only been right on the edge of qualifying as a proxy for Great Plains. As a result, given the uncertainty surrounding NiSource, the reasonable approach is to exclude the company from the proxy group.[243]

The Department also recommended that Great Plains exclude New Jersey Resources Corporation from its proxy group because S&P withdrew all of its credit ratings on May 24, 2019.[244] Ms. Bulkley criticized the Department's recommendation for two reasons. First, she claimed without further explanation that Mr. Addonizio used a different operating income screen for New Jersey Resources than for the other potential proxy companies.[245] Specifically, Ms. Bulkley stated that Mr. Addonizio "relied on inconsistent data from 2019 and prior years," and "concluded that 2018 was an outlier year" for New Jersey Resources.[246]

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[241] Ex. DER-1 at 50 (Addonizio Direct); Ex. DER-9 at 11-12 (Addonizio Surrebuttal).
[242] Ex. DER-9 at 13 (Addonizio Surrebuttal); Ex. GP-16, AEB-3, Schedule 7 (Bulkley Rebuttal).
[243] Ex. DER-9 at 14 (Addonizio Surrebuttal).
[244] Ex. DER-1 at 50 (Addonizio Direct).
[245] Ex. GP-16 at 25-26 (Bulkley Rebuttal).
[246] Ex. GP-16 at 26 (Bulkley Rebuttal).

In his surrebuttal testimony, Mr. Addonizio wagered two guesses regarding what Ms. Bulkley might have found inconsistent about his operating income screen for New Jersey Resources. However, neither Ms. Bulkley's claim that Mr. Addonizio's operating income screen was inconsistently applied nor Mr. Addonizio's explanation are ultimately relevant. Mr. Addonizio recommended New Jersey Resources' exclusion because the company lacks an S&P credit rating not because of its operating income.[247]

Second, Ms. Bulkley disagreed with Mr. Addonizio's requirement that proxy group members have an S&P credit rating. Ms. Bulkley argued that while New Jersey Resources itself is not a rated entity, its utility subsidiary, New Jersey Natural Gas, was a rated entity.[248] However, Ms. Bulkley's reliance on S&P's withdrawn credit rating for New Jersey Natural Gas to justify New Jersey Resources' inclusion as a proxy company is unreasonable because it was based on unsupported speculation. Ms. Bulkley's rebuttal testimony assumed without basis that S&P would continue to maintain the same credit rating for New Jersey Natural Gas today that it had in May 2019.[249] It is not necessary to speculate about what S&P's credit rating would be currently for New Jersey Natural Gas. Currently, no New Jersey Resources-related entity has a credit rating from S&P. As a result, no weight should be given to any S&P credit ratings for New Jersey Resources in this proceeding.

Ms. Bulkley also argued that New Jersey Resources should be included in the proxy group because New Jersey Natural Gas has an investment grade credit rating from Moody's.[250] She explained, "Mr. Addonizio's sole reliance on S&P for his credit rating screen is

[247] Ex. DER-9 at 20-21 (Addonizio Surrebuttal).
[248] Ex. GP-16 at 27-28 (Bulkley Rebuttal).
[249] Ex. DER-9 at 22 (Addonizio Surrebuttal).
[250] Ex. GP-16 at 27-28 (Bulkley Rebuttal); Ex. DER-9 at 22 (Addonizio Surrebuttal).

unnecessarily restrictive[.]"[251] The problem with Ms. Bulkley's use of an alternative credit rating is not with the credit rating agency, but rather the type of credit rating that Moody's issued. In their proxy screening processes, both Ms. Bulkley and Mr. Addonizio relied on issuer-level credit ratings for potential proxy companies to determine if those companies were suitable proxies for Great Plains.[252] However, Moody's credit rating for New Jersey Natural Gas is not an issuer-level credit rating. Issuer-level credit ratings are based on an entity's ability to "honor senior *unsecured* debt and debt like obligations."[253] In contrast, Moody's credit rating for New Jersey Natural Gas (NJNG) is based on its ability to pay *secured* debt.[254] Mr. Addonizio explained why this difference between secured and unsecured debt matters:

> Secured debt has a higher claim priority than unsecured debt; accordingly, it is less risky than unsecured debt and results in higher credit ratings. . . . Ms. Bulkley is taking a credit rating . . . based on NJNG's ability to pay secured debt and treating it like a credit rating . . . based on the ability to pay unsecured debt. This results an overstatement of NJNG's creditworthiness.[255]

The difference between ratings on unsecured and secured debt alone is enough to render Moody's credit rating for New Jersey Natural Gas meaningless in the context of this proceeding. However, Moody's credit rating for New Jersey Natural Gas may be even less relevant than the unsecured/secured distinction implies because neither Ms. Bulkley nor Mr. Addonizio could determine whether the rating applied beyond a specific debt issuance by New Jersey Natural Gas made in conjunction with the New Jersey Economic Development Authority.[256]

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[251] Ex. GP-16 at 28 (Bulkley Rebuttal).
[252] Ex. DER-9 at 23 (Addonizio Surrebuttal
[253] Ex. DER-9 at 23 (Addonizio Surrebuttal) (quoting MOODY'S INVESTOR SERVICE, RATING SYMBOLS AND DEFINITIONS 9 (2020), available at https://perma.cc/FB7Z-Z866).
[254] Ex. DER-9, CMA-S-19 at 2 (Addonizio Surrebuttal).
[255] Ex. DER-9 at 25 (Addonizio Surrebuttal).
[256] Ex. DER-9 at 25-26 (Addonizio Surrebuttal).

Ms. Bulkley also argued that a FitchRating's credit rating could be used as a substitute for an S&P issuer-level credit rating for New Jersey Natural Gas.[257] Mr. Addonizio had less concern with use of the FitchRating's credit rating. However, he noted that Fitch is not regularly used as a source of credit ratings in rate case proceedings, and only three of the fourteen potential proxy group companies are rated by FitchRating.[258] As a result, it may not be appropriate to rely on FitchRating's credit ratings. Mr. Addonizio also noted that New Jersey Resources' inclusion, as advocated by Ms. Bulkley, in the proxy group would lower the Department's recommended two-growth DCF result by nine basis points from 8.82 percent to 8.73 percent.[259]

b. Ms. Bulkley's Decision to Use 90- and 180-Trading-Day Periods was Unreasonable

Basic financial theory holds that current stock prices fully reflect all publicly available information. Thus, the use of long-term historical prices may result in dividend yields that reflect irrelevant information. Under this principle, Ms. Bulkley's use of prices over the 90- and 180-trading-day periods to calculate her dividend yields was unreasonable.[260] Ms. Bulkley's mean constant growth DCF ROE estimates calculated using 90- and 180-trading-day average dividend yields (9.88 percent and 9.97 percent) are seven basis points and sixteen basis points higher, respectively, than her mean ROE estimate based on a 30-trading-day average dividend yield (9.81 percent).[261]

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[257] Ex. GP-16 at 28 (Bulkley Rebuttal).
[258] Ex. DER-9 at 27 (Addonizio Surrebuttal).
[259] Ex. DER-9 at 27-28 (Addonizio Surrebuttal); Ex. DER-9, CMA-S-23 (Addonizio Surrebuttal).
[260] Ex. GP-14 at 52 (Bulkley Direct).
[261] Ex. GP-14, AEB-2, Schedule 2 (Bulkley Direct).

c. Ms. Bulkley's Decision to Use Value Line's 27.0 Percent Growth Rate for Northwest Natural was Unreasonable

Ms. Bulkley's decision to use Value Line's 27.0 percent growth rate for Northwest Natural was unreasonable.[262] The 27.0 percent growth rate is inflated, unrepresentative of Value Line's assessment of Northwest Natural's expected earnings growth, and is not suitable for use in a DCF analysis.[263] Mr. Addonizio noted that excluding Value Line's growth rate for Northwest Natural from Ms. Bulkley's analysis lowers the mean average ROE from her 30-day constant growth DCF analysis by 96 basis points, from 9.91 percent to 8.95 percent. The impact that a single growth rate had on Ms. Bulkley's constant DCF analysis illustrates the unreasonableness of using that growth rate at all.[264]

d. Ms. Bulkley's Two-Growth DCF Analyses Suffered From the Same Defects

Ms. Bulkley's two-growth DCF analyses suffered from the same defects as her constant growth DCF analyses described above.[265] First, Ms. Bulkley used 90- and 180-day averaging periods for the proxy companies' stock prices that reflect out-of-date, irrelevant information. Second, Ms. Bulkley included Value Line's 27.0 percent earnings growth rate estimate for Northwest Natural.[266] Third, Ms. Bulkley's flotation adjustment erroneously assumed all of Great Plains' equity issuances incurred flotation costs. As a result, her flotation cost percentage may be overstated, and her resulting adjustment of ten basis points may be too large.[267] For these reasons, Ms. Bulkley's two-growth DCF analysis results in an unreasonable ROE range.

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[262] Ex. GP-14, AEB-2, Schedule 5 (Bulkley Direct).
[263] Ex. DER-1 at 52-53 (Addonizio Direct).
[264] Ex. DER-1 at 53 (Addonizio Direct).
[265] Ex. GP-14 at 55-56 (Bulkley Direct).
[266] Ex. DER-1 at 53 (Addonizio Direct).
[267] Ex. DER-1 at 54-55 (Addonizio Direct).

e. Historical Data

Ms. Bulkley's direct testimony asserted that the DCF and CAPM rely on historical data.[268] This claim is inaccurate. As Mr. Addonizio repeatedly testified, "Asset prices, including stock and bond prices, represent the collective assessment of investors of the present value of future cash flows associated with those assets and the risk associated with those cash flows."[269] Stock prices and interest rates are by their very nature forward looking. Accordingly, describing stock prices and interest rates as "historical" fundamentally misrepresents how markets set prices.

2. Ms. Bulkley's CAPM Analyses

a. Ms. Bulkley's Use of Forecasted Bond Yields was Unreasonable

Ms. Bulkley's use of forecasted bond yields to determine the risk-free rate is unreasonable.[270] Long-term interest rates, including yields on Treasury bonds, are determined by market forces. In this way, current bond yields already reflect investor expectations about future economic and financial conditions.[271] Since current bond yields reflect expected future developments, any changes to bond yields in the future will necessarily reflect unanticipated developments that cause investors to adjust their expectations.[272] Forecasted bond yields suffer from the fact that it is challenging to forecast unanticipated future events. Moreover, if these future developments were anticipated, then current bond yields would already reflect these anticipated changes. Thus, Ms. Bulkley's use of a long-term forecasted 30-year Treasury bond

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[268] *See, e.g.*, GP-14 at 51 (Bulkley Direct).
[269] Ex. DER-1 at 71 (Addonizio Direct).
[270] Ex. GP-14 at 66-67 (Bulkley Direct).
[271] Ex. DER-1 at 56 (Addonizio Direct).
[272] Ex. DER-1 at 56 (Addonizio Direct).

yields over the period 2021-2025 is particularly inappropriate.[273] Such long-term forecasts are subject to too much uncertainty to be relied upon and the ROE estimates produced with them should be given little to no weight.[274]

b. Ms. Bulkley's Market Rate of Return and Beta were Reasonable

Ms. Bulkley's estimate of the required market return and choice of beta for Great Plains both appear to be reasonable.[275] However, her estimate of the required market return of 13.90 percent is significantly higher than Mr. Addonizio's estimate of 12.92 percent – a difference of more than 150 basis points – even though they both used similar approaches and relied on respected datasets This wide deviation again illustrates why the CAPM should only be used as a check on the reasonableness of the DCF analyses.[276]

3. Ms. Bulkley's Use of Bond Yield Plus Risk Premium Analysis was Unreasonable

The Bond Yield Plus Risk Premium approach, employed by Ms. Bulkley, treats ROE as a sum of a bond yield plus an equity risk premium. Ms. Bulkley used historical data, going back to 1992, to estimate the historical relationship between the equity risk premium for gas utilities and the yield on 30-year U.S. Treasuries. She then derived an estimate of the current equity risk premium by applying that historical relationship to current 30-year Treasury yields, as well as two forecasts of 30-year Treasury yields.[277]

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[273] Ex. GP-14 at 67-68 (Bulkley Direct).
[274] Ex. DER-1 at 56-57 (Addonizio Direct).
[275] Ex. GP-14 at 68-69 (Bulkley Direct).
[276] Ex. DER-1 at 57-58 (Addonizio Direct).
[277] Ex. DER-1 at 58-59 (Addonizio Direct); Ex. DER-9 at 57 (Addonizio Surrebuttal).

Bond Yield Plus Risk Premium analysis is not a theoretically sound way to determine Great Plains' ROE because it is backward looking, rather than forward-looking.[278] The Bond Yield model assumes that the relationship between the equity risk premium for gas distribution utilities and treasury yields does not depend on investors adjusting their expectations depending on different economic and financial conditions such as changing federal monetary and fiscal policies.[279] In this way, Ms. Bulkley's analysis ignores all other economic and financial conditions that may affect investors' expectations and return requirements.[280]

Beyond these theoretical flaws, Ms. Bulkley's application of the Bond Yield approach suffers from some of the same defects as her DCF and CAPM analyses. Ms. Bulkley used the same forecasted interest rates in her Bond Yield Plus Risk Premium analysis that she used in her CAPM analyses. These forecasted interest rates are subject to too much uncertainty to produce an ROE that can be reasonably relied upon and are inferior to current interest rates as predictors of future interest rates. Actual bond yields already reflect investor expectations about the future. It is unreasonable to rely on forecasts that depend on the occurrence of unanticipated and currently unknowable events.[281]

Ms. Bulkley's rebuttal testimony failed to respond to Mr. Addonizio's concerns. Instead, she emphasized that her analysis is backwards looking, stating, "my Risk Premium analysis determines the appropriate risk premium based on the relationship between historic authorized ROEs for natural gas utilities and Treasury bond yields" and "my Risk Premium analysis is

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[278] Ex. GP-14 at 73-77 (Bulkley Direct).
[279] Ex. DER-1 at 59 (Addonizio Direct).
[280] Ex. DER-1 at 59-60 (Addonizio Direct).
[281] Ex. DER-1 at 60-61 (Addonizio Direct).

designed to use the historical relationship between bond yields and the equity risk premium[.]"[282] Yet, this is exactly the Department's concern: analyzing the historical relationship between Treasury yields and utility equity returns ignores relevant factors in a way that make Bond Yield analysis an unreasonable way to estimate the going-forward equity risk premium.[283] Nothing in Ms. Bulkley's response demonstrated that the Department's concern was unreasonable or unfounded. As a result, no weight should be placed on Great Plains' Bond Yield analysis.

4. Ms. Bulkley's Use of the Expected Earnings Methodology was Unreasonable

Like the Bond Yield approach, the Expected Earnings Methodology applied by Ms. Bulkley is not a theoretically sound way to estimate Great Plains' ROE.[284] The Expected Earnings methodology is an accounting-based methodology, not a market-based one. It estimates a rate of return on the book value of a company's equity. Yet, investors cannot purchase shares of common stock at their book value. Investors must pay the current market value for shares.[285]

Additionally, FERC Opinion 569 similarly held that the Expected Earnings Methodology is inappropriate for determining ROE. Like Mr. Addonizio, FERC explained, "The Expected Earnings methodology provides an accounting-based approach that uses investment analyst estimates of return . . . on book value[.]"[286] FERC concluded:

> 201. In particular, we find that the record does not support departing from our traditional use of market-based approaches to determine base ROE. Under the market-based approach, the Commission sets a utility's ROE to equal

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[282] Ex. GP-16 at 62 (Bulkley Rebuttal).
[283] Ex. DER-9 at 58 (Addonizio Surrebuttal).
[284] Ex. GP-14 at 77-79 (Bulkley Direct).
[285] Ex. DER-1 at 60-61 (Addonizio Direct).
[286] Opinion No. 569, *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. System Operator, Inc.*, 169 F.E.R.C. ¶ 61,129, 61,301 (slip op., para. 172) (2019), available at www.ferc.gov/whats-new/comm-meet/2019/112119/E-11.pdf.

> the estimated return that investors would require in order to purchase stock in the utility at its current market price. In *Hope*, the Supreme Court explained that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."
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> . . . .
>
> 202. The return on book value is also not indicative of what return an investor requires to invest in the utility's equity or what return an investor receives on the equity investment, because those returns are determined with respect to the current market price that an investor must pay in order to invest in the equity.[287]

In this way, FERC reasoned that it would be illogical to set ROE based on book value when actual equity investment must be made at the company's current market price.

Ms. Bulkley did not directly respond to Mr. Addonizio's direct testimony criticisms. Instead, Ms. Bulkley attempted to justify the use of the Expected Earnings methodology by relying on the exact same logic that FERC rejected in its Opinion 569. She also included a quote from NEW REGULATORY FINANCE in support of her position.[288]

Ms. Bulkley's use of NEW REGULATORY FINANCE was unreasonable because she improperly conflated her Expected Earnings methodology with Dr. Morin's Comparable Earnings methodology.[289] Dr. Morin's Comparable Earnings methodology requires that the target utility's proxy group not include other utility companies. In contrast, Ms. Bulkley's proxy group exclusively contained gas distribution utilities. It is unreasonable to extend the arguments supporting Dr. Morin's Comparable Earnings to Ms. Bulkley's Expected Earnings approach because Ms. Bulkley did not use the same inputs as Dr. Morin.[290]

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[287] *Id.* ¶ 61,329-330 (slip op., paras. 200-201) (citing *Fed. Power Comm'n, vs. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944)).
[288] Ex. DER-9 at 59 (Addonizio Surrebuttal); ROGER A. MORIN, NEW REGULATORY FINANCE (Pub. Utils. Rep., Inc. 2006).
[289] Ex. DER-9 at 61 (Addonizio Surrebuttal).
[290] MORIN, NEW REGULATORY FINANCE at 383.

In this way, Expected Earnings analysis is fundamentally different from Comparable Earnings analysis. None of Dr. Morin's arguments in favor of the Comparable Earnings methodology can reasonably be applied to Ms. Bulkley's Expected Earnings analysis. Moreover, Ms. Bulkley's Expected Earnings analysis is subject to the circularity problem that Dr. Morin described in his textbook because Ms. Bulkley included other utilities in her proxy group.[291] Further, as Dr. Morin makes clear, investors cannot invest at book value, and thus, book-based rates of return are not representative of the returns available to investors, as Mr. Addonizio's direct testimony described and as FERC Opinion 569 concluded.[292]

For these reasons, Ms. Bulkley's Expected Earnings analysis should be given no weight.

5. It is Unreasonable to Make Unspecified ROE Adjustments Based on Qualitative Analysis

Finally, Ms. Bulkley used qualitative analysis with a tenuous connection to Great Plains to make unspecified adjustments to her recommended ROE. In particular, Ms. Bulkley discussed Great Plains' size and customer concentration, current financial market conditions, and ROEs authorized for other utilities. Ms. Bulkley did not, however, explain how her recommended ROE reflects these factors. And, in any case, none of these adjustments are reasonable to consider in determining Great Plains' ROE.

All companies, utilities included, face a wide variety of risk factors, and each company faces a unique set of risk factors. In-depth micro-analyses of all of the individual business and financial risk factors must be conducted to reasonably compare the risk profiles of different

[291] MORIN, NEW REGULATORY FINANCE at 383.
[292] MORIN, NEW REGULATORY FINANCE at 393; Ex. DER-9 at 62-63 (Addonizio Surrebuttal).

companies. Ms. Bulkley's analysis is only a high-level analysis of a small number of broad categories of risk.[293]

a. Size-Related Risks

Ms. Bulkley's direct testimony made an unsupported assertion that smaller utilities are riskier than larger utilities.[294] While smaller businesses, particularly in the competitive market, may experience a "size effect" as described by Ms. Bulkley, it may not necessarily apply to rate regulated utilities.[295] Mr. Addonizio explained:

> Non-regulated firms operate in much different circumstances than regulated firms, and cannot seek rate relief from a public utilities commission in the event of the loss of a large customer or a downturn in the overall economy. Because of that important difference, empirical findings related to non-regulated firms cannot simply be applied to regulated firms as though the firms are equals.[296]

As a result, the articled cited in Ms. Bulkley's direct testimony in support of her position provides little value. As the article notes, "a consensus has not yet been formed on why small stocks behave as they do."[297] Importantly, it cannot be assumed that a small size effect applies equally to both competitive firms and rate-regulated utilities because the reasons the effect may exist are unknown. The article is not an empirical study of the impact of size on utility returns.[298] Rather, the article merely applies size premiums calculated using data for stocks listed on the New York Stock Exchange and assumes they apply equally to utilities.[299] As Mr. Addonizio noted, empirical evidence suggests that since the mid-1980s, firm size has not

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[293] Ex. DER-1 at 64 (Addonizio Direct).
[294] Ex. GP-14 at 80-85 (Bulkley Direct).
[295] Ex. DER-1 at 66 (Addonizio Direct).
[296] Ex. DER-1 at 67 (Addonizio Direct).
[297] Ex. DER-1, CMA-23, Michael Annin, *Equity and the Small-Stock Effect*, PUB. UTILS. FORT., Oct. 15, 1995, at 42.
[298] Ex. DER-1 at 67 (Addonizio Direct).
[299] Ex. DER-1 at 67 (Addonizio Direct).

had any impact on equity returns. Thus, to the extent a size effect ever existed and applied to utilities, evidence suggests that it no longer does.[300]

In response to Mr. Addonizio's direct testimony, Ms. Bulkley asserted that the Department did "not specifically considered the business risks of the Company as compared to the proxy group."[301] However, Mr. Addonizio included a lengthy discussion regarding the differences in risk between Great Plains and the proxy companies. Based on this analysis, he concluded that it was neither necessary nor appropriate to adjust his ROE recommendation to account for any such differences.[302]

For these reasons, Ms. Bulkley's size-related risk analysis is unsupported and should not be given any weight.

b. Service Territory and Customer Concentration

Ms. Bulkley next concluded that Great Plains is subject to greater risk than other companies in her proxy group because of its reliance on commercial and industrial customers.[303] This conclusion is unreasonable for several reasons. First, Ms. Bulkley's own proxy group included four other companies with industrial and commercial delivery percentages greater than sixty percent.[304] Second, Ms. Bulkley relied on a study that excluded utilities for the proposition that there is a relationship between the cost of equity and customer concentration.[305] However, it is not reasonable to simply apply conclusions derived from businesses in competitive markets and apply them to rate-regulated monopoly businesses.[306] Mr. Addonizio explained:

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[300] Ex. DER-1 at 66 (Addonizio Direct).
[301] Ex. GP-16 at 68 (Bulkley Rebuttal).
[302] Ex. DER-1 at 64-65 (Addonizio Direct); Ex. DER-9 at 66 (Addonizio Surrebuttal).
[303] Ex. GP-14 at 85-87 (Bulkley Direct); Ex. DER-1 at 68 (Addonizio Direct).
[304] Ex. DER-1 at 69 (Addonizio Direct).
[305] Ex. DER-1 at 68 (Addonizio Direct).
[306] Ex. DER-1 at 67 (Addonizio Direct).

> [I]f a non-regulated firm loses a large customer, it cannot simply raise its prices to make up for any of the lost revenue. Its ability to raise prices is limited by the degree of competition it faces and the prices its competitors charge. A regulated utility, on the other hand, can raise its rates to recover a perhaps significant portion of the lost revenue as fast as it can file a rate case and have interim rates take effect.[307]

As a result, investors may view concentration risks differently when evaluating utilities like Great Plains as opposed to businesses in competitive markets. For these reasons, Ms. Bulkley's conclusions regarding customer concentration and service territory are unsupported and should be given no weight.

c. Current Market Conditions

Ms. Bulkley asserted that interest rates on government bonds have been driven lower as a result of market uncertainty.[308] She next claimed that this decrease in interest rates has caused a decrease in the cost of capital for utilities, which in turn has caused utility valuations (i.e., stock prices) to increase above historical levels. Ms. Bulkley asserted that utility valuations should be expected to fall in the future as a result.[309] On this basis, Ms. Bulkley concluded that the DCF model, which uses stock prices as an input, is overstating the cost of equity for utilities.

Ms. Bulkley's conclusion is unreasonable because it is inconsistent with financial theory. A reasonable investor will not hold an investment that he or she believes will perform poorly in the future.[310] If investors expect the price of a stock to fall, they are likely to sell the stock, bidding the price of the stock down until it reaches a point at which the expected return meets investors' required return. If investors expect interest rates to rise in the future, and also expect that rise to negatively impact the price of their stock holdings, they will bid the price of their

[307] Ex. DER-1 at 69 (Addonizio Direct).
[308] Ex. GP-14 at 17-40 (Bulkley Direct).
[309] Ex. DER-1 at 69-70 (Addonizio Direct).
[310] Ex. DER-1 at 70 (Addonizio Direct).

stock holdings down until its expected return matches its required return.[311] In this way, market uncertainty is already fully reflected in stock prices.

Since DCF analyses rely on current stock prices to estimate the cost of equity, the results of those models also reflect current investor expectations. Ms. Bulkley's additional adjustments intended to reflect investor expectations are not only unnecessary, they are inappropriately duplicative.[312] For these reasons, Ms. Bulkley's market conditions analysis is unsupported and no weight should be given to it.

d. Ms. Bulkley's Adjustments

Despite engaging in this qualitative analysis, Ms. Bulkley did not make any direct connections between her assessment of market conditions and her reasonable ROE range of 9.75-10.25 percent.[313] She simply asserted that the range reflects her assessments of company-specific factors and capital market conditions.[314] The low end of that range, 9.75 percent, is approximately the average of her mean two-growth DCF results (9.77 percent), but it is not clear how, using her qualitative factors, she determined the upper limit of 10.25 percent. It also is not clear how Ms. Bulkley selected 10.20 percent from that range, particularly given her assertion that the entire range reflects her assessments of additional factors.[315]

In summary, size and customer mix are not relevant considerations. Ms. Bulkley's capital market conclusions are contrary to financial theory. And, a concrete connection between her qualitative analysis and the Company's ROE recommendation was not drawn. For these reasons, Ms. Bulkley's qualitative analysis should be given no weight.

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[311] Ex. DER-1 at 70 (Addonizio Direct).
[312] Ex. DER-1 at 70-71 (Addonizio Direct).
[313] Ex. GP-14 at 92-93 (Bulkley Direct).
[314] Ex. GP-14 at 39-40 (Bulkley Direct).
[315] Ex. DER-1 at 74 (Addonizio Direct).

6. Ms. Bulkley Failed to Draw a Reasonable Connection Between Her Analysis and Recommended ROE

Overall, in addition to her qualitative analysis, Ms. Bulkley failed to draw clear connections between her analytical model results and her recommended ROE. As Mr. Addonizio explained, it is not clear how Ms. Bulkley used her model results to derive her recommended ROE in either her direct or rebuttal testimony. Similarly, Ms. Bulkley's failure to update her recommendation in her rebuttal testimony also is unreasonable given the fact that many of the model results presented in Ms. Bulkley's rebuttal testimony are significantly different from the model results presented in her direct testimony.[316]

Ms. Bulkley's rebuttal testimony DCF results are 22 to 52 basis points higher than her direct testimony results. In contrast, her CAPM results are 62 to 70 basis points lower. Additionally, the mean and mean high results of her 90-day and 180-day DCF results, respectively, fell by 25 to 37 basis points and 12 to 24 basis points. Ms. Bulkley's Bond Yield Plus Risk Premium and Expected Earnings results also fell by 5 to 17 basis points.[317]

Ms. Bulkley's direct testimony stated that she relied largely on her mean and mean-high DCF results to establish a range of possible ROEs for Great Plains, and then used her other analyses to inform where within that range she placed her final recommendation.[318] Given the large changes in her DCF results, it is unclear why her recommended range did not change. However, Ms. Bulkley provided no discussion of how her updated results support her recommendation beyond simply noting that "while certain analytical results have changed since I filed my direct testimony, the results still support an ROE for Great Plains in the range of 9.75

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[316] Ex. DER-9 at 78 (Addonizio Surrebuttal).
[317] Ex. DER-9 at 79-80 (Addonizio Surrebuttal).
[318] Ex. GP-14 at 8 (Bulkley Direct).

percent to 10.25 percent."[319] Thus, Ms. Bulkley has not adequately explained how her analysis supports her final recommended ROE.

7. Ms. Bulkley's Weighted ROE Recommendation is Unreasonable

As described by Ms. Bulkley, weighted ROE is the product of a company's equity ratio and its authorized ROE.[320] Utilities, Great Plains included, have a great deal of control over their capital structure, and therefore their weighted ROE is in large part a function of their own choices related to the mix of debt and equity with which they choose to finance themselves. Ms. Bulkley calculated that Great Plains would need an authorized ROE of 10.07 percent in order to achieve an average weighted ROE of 5.11 percent, the average weighted ROE for other gas utilities in 2019.[321] However, as can clearly be seen in Figure 3 in her rebuttal testimony, a 10.07 percent authorized ROE would be significantly higher than the overwhelming majority of ROEs authorized during the last two years.[322] The reason it would need to be so high is that Great Plains has intentionally chosen to use a lower equity ratio than other gas utilities (i.e., by placing greater reliance on short- and long-term debt).[323] There is simply no need for the Commission to award Great Plains a higher ROE simply because the Company has chosen to use a lower equity ratio than other gas utilities.[324]

8. Conclusion Regarding Ms. Bulkley's Recommended ROE

For reasons discussed above, Ms. Bulkley's recommended ROE has not been shown to be reasonable and, thus, must be rejected.

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[319] Ex. GP-16 at 72 (Bulkley Rebuttal).
[320] Ex. GP-16 at 13 (Bulkley Rebuttal).
[321] Ex. GP-16 at 13 (Bulkley Rebuttal).
[322] Ex. GP-16 at 12 (Bulkley Rebuttal).
[323] Ex. DER-1 at 41-42 (Addonizio Direct).
[324] Ex. DER-9 at 72-73 (Addonizio Surrebuttal).

6. CAPITAL STRUCTURE

Resolved between DER and GP: DER and GP agreed that a capital structure of 50.815 percent equity, 45.132 percent long-term debt, and 4.053 percent short-term debt, as well as costs of short- and long-term debt of 3.693 percent and 4.712 percent, respectively, is reasonable.[325]

A. Great Plains' Proposed Equity to Debt Ratios are Reasonable

The term "capital structure" refers to the combination of short-term debt, long-term debt, and equity that a company uses to finance its activities. The ratio between debt and equity that a rate-regulated utility chooses will affect its overall rate of return.[326] In this case, Great Plains proposed to establish a capital structure consisting of 50.815 percent common equity, 4.053 percent short-term debt, and 45.132 percent long-term debt.[327] The Company considered the mean proportions of common equity, preferred equity, short-term debt, and long-term debt for the most recent year for each of the companies in its proxy group to develop a reasonable capital structure.[328] Great Plains also considered credit rating agency expectations in developing its proposal.[329]

To evaluate the proposal, the Department compared Great Plains' proposed capital structure to the average capital structures for the companies in the DER Proxy Group. The Department's review concluded that Great Plains' proposed equity ratio is almost equal to the DER Proxy Group's average and its short- and long-term debt ratios are within the ranges of the

[325] Ex. DER-9 at 2 (Addonizio Surrebuttal); Ex. GP-16 at 17 (Bulkley Rebuttal).
[326] Ex. DER-1 at 38 (Addonizio Direct).
[327] Ex. GP-14 at 107 (Bulkley Direct).
[328] *Id.*
[329] *Id.* at 108.

DER Proxy Group.[330] On this basis, the Department concluded that Great Plains' proposed equity, short-term, and long-term debt ratios are reasonable.[331]

B. Great Plains' Proposed Costs of Short- and Long-Term Debt Are Reasonable.

Great Plains proposed a short-term debt cost of 3.693 percent, including expense associated with the amortization of fees related to its revolving credit facility.[332] The Company proposed a long-term debt cost of 4.712 percent.[333] The Department evaluated the Company's proposal and concluded that both the short-term cost of debt and long-term cost of debt are reasonable. The Department further noted that Great Plains' proposed cost of long-term debt reflects the issuance of $275 million in new long-term debt in late 2019 and 2020.[334]

C. Great Plain's Decision to Eliminate Preferred Stock from its Capital Structure is Reasonable.

The Commission's NOTICE OF AND ORDER FOR HEARING directed the parties to address Great Plains' preferred stock redemption.[335] The Company stated that all outstanding preferred stock was redeemed on April 1, 2017. Great Plains indicated that preferred stock comprised approximately 0.6 percent of the Company's average capital structure in 2017. Great Plains explained that replacing preferred stock with a long-term debt issuance reduced its financing

[330] Ex. DER-1 at 40-41 (Addonizio Direct).
[331] *Id.*
[332] Ex. GP-2, Statement D-2 at 1 (Statement D – Rate of Return – Cost of Capital).
[333] Ex. GP-2, Statement D-1 at 1 (Statement D – Rate of Return – Cost of Capital).
[334] Ex. DER-1 at 42-43 (Addonizio Direct).
[335] *In the Matter of the Petition by Great Plain Natural Gas Co., a Division of Montana-Dakota Utilities Co., for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-004/GR-19-511, OAH Docket No. 65-2500-36528, NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 22, 2019).

costs. The Company stated that the preferred stock had dividend rates of 4.5 percent and 4.7 percent, while the long-term debt issuance has an interest rate of 3.36 percent.[336]

The Department reviewed Great Plains' decision to redeem the preferred stock and concluded that it was reasonable for two reasons. First, only two companies in the DER Proxy Group included preferred stock and only in small amounts. Second, Great Plains' assertion that redemption of the preferred stock reduced its financing costs was supported by the Company's preferred stock redemption net present value analysis.[337]

7. SALES FORECAST

Resolved between DER and Great Plains: The Department and the Company agree that the Commission should adopt Great Plains' test-year sales forecast filed in this proceeding. Great Plains agreed to retain customer data for future rate cases. The Company agreed that it will comply with paragraphs 16a through 16g of the GP 2015 RATE CASE ORDER in its future rate case applications. The OAG did not take a position on this issue. Ex. GP-18 (Shoemake Direct);Ex. GP-19 (Shoemake Rebuttal); Ex. GP-20 (Shoemake Summary); Ex. DER-2 (Shah Direct); Ex. DER-10 (Shah Surrebuttal); Ex. DER-17 (Shah Summary).

A. Forecast-Introduction

A "test year" is the 12-month period selected by the utility for the purpose of expressing its need for a change in rates.[338] Department witness, Mr. Sachin Shah, discussed the function and purpose of the sales forecast for use in the rate case test year.[339] He explained that test-year sales volumes are important because they are important factors in calculating a utility's revenue requirement, in that sales levels affect both revenues and expenses. In general, because sales levels are an integral input in calculating a utility's rates, the method of determining the sales levels must be reasonable. Therefore, reasonable sales forecasts are an essential part of the rate-

336 Ex. GP-12 at 5-6 (Nygard Direct).
337 Ex. DER-1 at 41-42 (Addonizio Direct); Ex. GP-2, Statement B-3 at 7 (Statement B – Rate Base – Preferred Stock Redemption) (20199-156154-02).
338 Minn. R. 7825.3100, subp. 17.
339 Ex. DER-2 at 2 (Shah Direct).

making process.[340] In designing rates, test-year sales volumes are used to allocate costs in the Class Cost of Service Study (CCOSS), which is then used as a benchmark comparison to establish the revenue apportionment. When establishing final rates, the test-year sales volumes are used to determine the overall revenue requirements, as well as the individual tariff rates.[341]

Based on his analysis in this case, Mr. Shah generally concluded that Great Plains' regression models and sales forecasts are reasonable and he recommended no adjustments to Great Plains proposed revenues.[342]

B. Great Plains' Forecast

Great Plains proposed a forecasted calendar year 2020 test year in this docket.[343] In his review to assess whether there was a need to adjust sales, Mr. Shah reviewed whether the forecast was based on "normal" conditions, with adjustments made for known and measurable changes. He explained that, at a minimum, the historical sales level must be adjusted to reflect sales that would occur under "normal" weather, since weather is typically the most significant factor affecting at least some rate classes.[344] Mr. Shah also explained the compliance requirement resulting from ordering paragraph 16a through 16g of Great Plains' last rate case,[345] with which the Company indicated it had complied.[346]

Great Plains divided its customers into seven customer classes: Residential, Small Firm, Large Firm, Small Interruptible, Large Interruptible, Large Transportation, Small Transportation

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[340] *Id*. at 2.
[341] *Id*. at 2-3.
[342] *Id*. at 3.
[343] Ex. GP 18, MTS-1 at 1-2 (Shoemake Direct);Ex. DER-2 at 4 (Shah Direct).
[344] Ex. DER-2 at 4 (Shah Direct).
[345] GREAT PLAINS 2015 RATE CASE ORDER at 51-52.
[346] Ex. GP-18 at 2-5 (Shoemake Direct); Ex. DER-2 at 5-6 (Shah Direct).

and Grain Dryers.[347] Mr. Shah reviewed the Company's forecast of test-year sales, noting that Great Plains forecasted test-year sales in the same manner as it did in its previous rate case (Ordinary Least Squares (OLS) regression analyses and averages to estimate test-year sales) with input changes that were improvements over the data used in Great Plains' last rate case.[348] He reviewed the source of the weather data Great Plains used to normalize sales in this rate case, as well as Great Plains' method for collecting and constructing the weighted weather data and whether that method used was reasonable. Mr. Shah concluded that Great Plains' method was appropriate since it attempts to match sales to weather data.[349] He reviewed how Great Plains calculated the normal weather data that it used in its forecasted test year and had no concerns regarding Great Plains' use of the weather data because, although the Company's methodology changed from the last rate case with respect to the years used in its calculations, the Commission, in a relatively recent 2019 order, accepted use of 30-year weather data.[350]

Mr. Shah explained that Great Plains' test-year sales forecast is the aggregate of several models for forecasting sales and the number of customers for its customer classes, and that summing these total sales for all rate classes yields the total sales for the Company.[351] He assessed how heat-sensitive test-year sales were estimated by Great Plains and how the normalized volumes were calculated for heat-sensitive customers, noting that the raw data was

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[347] Ex. GP-18 at 9-19, MTS-1 at 1-2 (Shoemake Direct) and Ex. GP-3 (Work papers, Statement C, Schedule C-1, pages 1-99) (September 27, 2019) (eDocket ID No. 20199-156154-03). Ex. DER-2 at 6 (Shah Direct).
[348] Ex. GP-18 at 5-19 (Shoemake Direct); Ex. DER-2 at 7 (Shah Direct).
[349] Ex. GP-18 at 5-8 (Shoemake Direct); Ex. DER-2 at 7-9 (Shah Direct).
[350] Ex. DER-2 at 9 (Shah Direct).
[351] *Id.* at 10 (Shah Direct).

accumulated in Excel files that were then processed through an analytical software referred to as Stata.[352]

Mr. Shah discussed the model specifications and methods used to estimate the residential, small firm, large firm, and other heat-sensitive customer class models and he concluded, regarding the general model specifications, that the transformations were reasonable, given the facts in this proceeding.[353] Mr. Shah explained how Great Plains estimated 2020 test-year sales for each firm rate class and each heat-sensitive interruptible and transportation customer and each non-heat-sensitive interruptible and transportation customer.[354]

In conclusion, after reviewing Great Plains' process to calculate input data and forecasting techniques and models, Mr. Shah had no major concerns with the Company's sales forecast approach and accompanying results.[355]

C. Continuation of the GP 2015 Rate Case Order Requirements (Paragraph 16a-16g)

Great Plains had compliance requirements from its last rate case related to sales volume forecasts. One such requirement required Great Plains to improve its forecast methodology in future rate filings by providing the certain information "to the extent practicable, or explaining why the information is not available," which information consisted of "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*."[356]

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[352] *Id.* at SS-2 (Shah Direct). Ex. DER-2 at 10-11 (Shah Direct).
[353] Ex.GP-18 at 12-14 (Shoemake Direct); Ex. DER-2 at 11-12 (Shah Direct).
[354] Ex. DER-2 at 12-13 (Shah Direct).
[355] Ex. DER-2 at 13 (Shah Direct). Mr. Shah did have one "minor concern" related to Great Plains' data retention, discussed in section IV. 7. D. below.
[356] *Id.* at 13-14 (Shah Direct) (*citing* GP 2015 Rate Case Order, Ordering Para. 16) (emphasis added).

The Company's forecast in this instant case did not use information going back at least 20 years. Great Plains' witness Mr. Shoemake explained why it failed to do so. He described the billing data he used in the weather normalization process, and discussed a Company history of changes in customer rate classes in 2004 and 2007.[357] Those changes resulted in, among other things, detailed billing data before 2007 that was not consistent with the currently effective rate structure, which, therefore, Great Plains did not use in the instant sales forecast. Mr. Shoemake explained that, for data prior to 2004, Great Plains would need to make assumptions about the historical billing in order to re-classify the data as residential or firm general service; and further, from 2004 through mid-2007, firm general service customers were all billed under the same rate classification, and assumptions would have to be made in order to re-classify the data for 2004 through mid-2007 as either small or large firm general service. Mr. Shoemake said that Great Plains chose to not utilize the data prior to 2007 to avoid making incorrect assumptions on any historical billing data not reflective of the Company's current rate structure. As a result, the Company included only 15 years of residential billing data and 11 years of firm general service billing data in its weather normalization process.[358]

The Department attempted to obtain the 2004 through 2007 data for the firm general classes by sending a series of IRs, however, Great Plains did not provide the requested data and instead provided further detailed reasons for its inability to provide data for the years prior to 2008.[359]

[357] *Id.* at 14 (Shah Direct).
[358] Ex. GP-18 at 8-11 (Shoemake Direct). Ex. DER-2 at 14-16 (Shah Direct).
[359] Ex. DER-2 at 16-17, SS-3 (Shah Direct) (GP Responses to Department IR Nos. 501-512).

Based on his review of all the information provided, including the Company's testimony and IR responses, Mr. Shah concluded that the Company complied with the GP 2015 RATE CASE ORDER'S requirement by adequately "explaining why the information is not available."[360]

In its rebuttal, the Company indicated that it opposed this recommendation, but said that the Company will comply with paragraphs 16a through 16g of the GP 2015 RATE CASE ORDER in its future rate case applications.[361]

D. Retention of Customer Data

To ensure the Company's future efforts to meet the Commission's requirements in ordering paragraph 16a through 16g of GP 2015 RATE CASE ORDER, Mr. Shah recommended that the Company be required to retain customer data such that, in the event it proposes different rate structures in the future that would impact future customer data sets, past data would remain available. He explained that the Company has maintained customer data in each of its respective billing systems that is similar – account numbers, service identification numbers, customer rate class, volumes billed (in dekatherms); therefore, on a going-forward basis for all customer classes, from 2008 onwards, the Company should be able to retain its customer data for future rate cases even if there is a change in the rate structure, given the unique identifiers described above that the Company maintains. If so ordered, going-forward, even if the Company decided to change its rate structure, it would not necessarily mean that the customer's historical consumption data changed or becomes unusable. This would help ensure that Great Plains has the historical data needed to develop its forecasts in future rate cases.[362]

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[360] *Id.* at 17 (Shah Direct).
[361] Ex. GP-19 at 2 (Shoemake Rebuttal); Ex. DER-10 at 2 (Shah Surrebuttal).
[362] Ex. DER-2 at 18 (Shah Direct).

During the prehearing settlement conference held on March 4, 2020 Great Plains agreed to the Department's recommendation that the Company be required to retain customer data for future rate cases if there is a change in the rate structure.[363] The Company further agreed that the question, of whether it is reasonable for the Company to make assumptions about its data in future cases in the event Great Plains proposes a change in rate structures in the future, can be decided in those future cases, and need not be addressed in this docket.[364]

8. CLASS COST OF SERVICE

Resolved between DER and Great Plains: The Department and the Company agreed that it is not necessary for the Commission to approve any of the Class Cost of Service Studies (CCOSSs) that Great Plains sponsored in this rate case. The Company agreed with (1) the Department's recommendations regarding the classification and/or allocation methods of seven FERC accounts discussed in Section III of the Ouanes Surrebuttal, (2) the Department's recommendation to perform an improved minimum-size study, with the use, for each type and size of pipe, of unit replacement cost ($ per foot) of its installed distribution pipes, and the Company will file in its next general rate case a CCOSS reflecting these recommendations. The OAG did not take a position on this issue. Ex. GP-2 (Statement E -- Rate Structure and Design); Ex. GP-25 at 3-12 (Hatzenbuhler Direct); Ex. GP-26 at 13-19 (Hatzenbuhler Rebuttal); Ex. GP-27 (Hatzenbuhler Summary); Ex. DER-3 (Ouanes Direct); Ex. DER-11 (Ouanes Surrebuttal); Ex. DER-18 (Ouanes Summary).

A. CCOSS Objective and Characteristics

The purpose of a CCOSS is to identify, the responsibility of each customer class for each cost incurred by the utility in providing service. The CCOSS can then be used as one important factor in determining how costs should be recovered from customer classes through rate design.[365] A CCOSS should reflect cost causality, which means that customer classes that impose costs on the system should be assigned their appropriate share of each cost.[366]

[363] Ex. DER-17 (Shah Summary).
[364] Ex. DER-10 at 4-8 (Shah Surrebuttal); Ex. DER-17 (Shah Summary).
[365] Ex. DER-3 at 3 (Ouanes Direct).
[366] *Id.*

There are three steps in performing a CCOSS. First, costs are functionalized, or grouped according to their purpose. Second, costs are classified into three basic categories: 1) customer costs, 2) energy or commodity costs, and 3) demand or capacity costs. Third, costs are allocated to the various customer classes.[367]

Department witness, Dr. Samir Ouanes explained that costs are typically functionalized by the Uniform System of Accounts as provided by the Federal Energy Regulatory Commission (FERC). These accounts group costs into their various functions, such as production (costs associated with producing, purchasing, or manufacturing gas), storage (costs associated with storing gas normally during off-peak for use in times of cold weather), transportation (costs incurred in transporting gas from interstate pipelines to the distribution system), distribution (costs incurred to deliver the gas to the customers, such as gas distribution mains and meters) and other costs (costs that do not fit the above functions, such as general and administrative costs).[368]

The functionalized costs are then classified. They are generally classified[369] as customer, demand, or energy costs according to how they are incurred:

- Customer costs are those operating and capital costs found to vary with the number of customers served rather than with the amount of utility service supplied. They include costs associated with "the theoretical distribution system that would be needed to serve customers at nominal or minimal load conditions."[370]
- Demand or Capacity costs are those costs incurred to serve the peak demand on the system and do not directly vary with the number of customers or their annual usage.

[367] *Id.* at 3-4, SO-3 at 1 (Ouanes Direct) (*Gas Distribution Rate Design Manual of the National Association of Regulatory Utility Commissioners* at 20, June 1989 (Gas Manual)).
[368] *Id.* at 3, SO-3 at 1-3 (Gas Manual at 20-22).
[369] Functionalized costs that may not be readily categorized as customer, energy, or demand are generally classified and allocated on a composite basis of other cost categories. For example, administrative and general expenses may be classified and allocated on the same basis as the sum of the other operating and maintenance expenses, excluding the cost of gas. Ex. DER-3 at 4-5, SO-3 at 7 (Ouanes Direct) (Gas Manual at 26).
[370] Ex. DER-3, SO-4 (Ouanes Direct) (January 1, 1987 *Gas Rate Fundamentals of the American Gas Association* at 136).

They include "the costs associated with distribution mains in excess of the minimum size [the theoretical distribution system that would be needed to serve customers at nominal or minimal load conditions]."[371]

- Energy or Commodity costs consist of those costs that vary with the quantity of gas consumed.[372]

The functionalized and classified costs are then allocated. They are usually allocated[373] to customer classes as follows:[374]

- Customer costs are allocated among the customer classes based on the number of customers in each class, typically weighted to reflect, for example, differences in metering costs among customer classes;
- Demand or Capacity costs are allocated among the customer classes based on the demand imposed on the system by each class during specific peak hours; and
- Energy or Commodity costs are allocated among the customer classes based on the energy the system must supply to serve the various customer classes.

As indicated above, each customer class's cost of service will depend not only on the CCOSS, but also on all the values of the exogenous variables of this mathematical model[375] including but not limited to the sales forecasts. Each customer class's revenue requirement will depend not only on the Commission's decision on specific classification and allocation methods

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371 Ex. DER-3, SO-3 at 4-5 (Ouanes Direct) (Gas Manual at 23-24).
372 *Id,* SO-3 at 4 (Gas Manual at 23).
373 The functionalized and classified costs that may not be readily categorized as customer, energy, or demand are generally allocated on a composite basis of other cost categories. For example, administrative and general expenses may be allocated on the basis of the sum of the other operating and maintenance expenses, excluding the cost of gas. *Id.* at 6, SO-3 at 7 (Gas Manual at 26).
374 *Id.* at 6.
375 *Id*. at 7 (Dr. Ouanes explained that the CCOSS is a mathematical model consisting of two types of variables, endogenous and exogenous variables, and a set of equations (relationships between variables). Endogenous variables are the variables that are determined within the model. For example, the Residential class's revenue requirement (or cost of service) is an endogenous variable determined within the model, and its value becomes known only after running the CCOSS. Exogenous variables are the variables whose values come from outside of the model. For example, test year costs by FERC account, sales data, or the rate of return are exogenous variables because they are set outside of the CCOSS. The values of the endogenous variables are, by construction, dependent on the values of the exogenous variables and the specific relationships between variables included in the model

within the CCOSS, but also on the Commission's decision on specific exogenous variables of the CCOSS, such as the amounts and items in the rate base, expenses, the rate of return, and sales forecast.[376]

The Commission's decision on specific classification and allocation methods within the CCOSS and on specific exogenous variables of the CCOSS, such as the amounts and items in the rate base, expenses, the rate of return, and sales forecast, will be reflected in final rates.[377]

B. Great Plains' Embedded CCOSS

As required by the GREAT PLAINS 2015 RATE CASE ORDER,[378] the Company filed three embedded cost studies: two Minimum System method CCOSSs, and the Basic Customer method CCOSS. Great Plains used the Basic Customer method CCOSS as the Company's starting point for its proposed rate design.[379] The Minimum System method CCOSS and the Basic Customer method CCOSS differ in the way they classify Distribution Mains, which are included in FERC Account No. 376. The Basic Customer method CCOSS classifies distribution mains as 100 percent demand-related costs,[380] unlike the Company's two Minimum System

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[376] *Id*. at 7-8.
[377] *Id*. at 8 (referencing testimony of Mr. Michael Zajicek, Department witness on the topic of "rate design.")
[378] Ex. DER-3 at 9-10 (Ouanes Direct) (*citing* GREAT PLAINS 2015 RATE CASE ORDER at 36. (In the GREAT PLAINS 2015 RATE CASE ORDER, the Commission found no reliable CCOSS in the record, and decided to retain the Company's then-current class allocation, as recommended by the Department and the OAG. The Commission reasoned that "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.").
[379] Ex. GP-25 at 11 (Hatzenbuhler Direct); Ex. DER-3 at 8 (Ouanes Direct).
[380] Ex. GP-2 at 24-53 of 61 (Vol. III -- Statement E -- Rate Structure and Design") (September 27, 2019) (Great Plains Statement E, Schedule E-2b), publ. at: Great Plains Proposed CCOSS; *see also* Ex. GP- 25 at 11 (Hatzenbuhler Direct).

method CCOSSs, the "MS1 CCOSS" and the "MS2 CCOSS,"[381] in which the Company classified distribution mains between demand-related and customer-related costs, based on a minimum-size analysis.[382]

Department witness Dr. Ouanes discussed the studies Great Plains used in this rate case to produce inputs to its proposed CCOSS. Although the studies were based on reasonably current data,[383] Great Plains' proposal misclassified or misallocated costs associated with the following FERC accounts:[384]

1) FERC Account No. 374, Land and Land Rights.
2) FERC Account No. 375, Structures and Improvements.
3) FERC Account No. 886, Maintenance of Structures and Improvements.
4) FERC Account No. 387, Other Equipment.
5) FERC Account No. 385, Industrial Measuring and Regulating Station Equipment.
6) FERC Account No. 890, Maintenance of Measuring and Regulating Station Equipment-Industrial.
7) FERC Account No. 876, Measuring and Regulating Station Expenses-Industrial.
8) FERC Account No. 892, Maintenance of Services.

For example, as to FERC Account No. 374, the Company misclassified Land and Land Rights as solely demand costs. According to the Code of Federal Regulations (C.F.R.),[385] that account includes the cost of land and land rights used in connection with distribution operations, and for that reason, is not to be classified solely as demand costs (nor solely as customer or

[381] Ex. GP-2 at 20-54 and 63-97 of 105 ("Workpapers -- Statement E -- Rate Structure and Design") (September 27, 2019) (Great Plains Alternative E-2), publ. at: Great Plains Alternative CCOSSs; *see also* Ex. GP-25 at 9-11 (Hatzenbuhler Direct).
[382] Ex. DER-3 at 9 (Ouanes Direct).
[383] *Id.* at 10, SO-5.
[384] *Id.* at 10-11.
[385] 18 C.F.R. 201 (Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act), Account 374.

energy costs). Accordingly, Dr. Ouanes recommended that Land and Land Rights be classified and allocated on the same basis as Distribution Plant.[386]

Similarly, as to FERC Account No. 375, the Company classified Structures and Improvements as solely demand costs. According to the C.F.R., however, this account includes the cost in place of structures and improvements used in connection with distribution operations.[387] Accordingly, because Structures and Improvements are used in connection with distribution operations, Dr. Ouanes recommended that Structures and Improvements should be re-classified and re-allocated on the same basis as Distribution Plant.[388]

In a similar fashion, Dr. Ouanes' Direct Testimony discussed each of the remaining FERC accounts that the Company had misclassified and misallocated in its initial filing.[389]

In its rebuttal testimony, Great Plains stated that these accounts represented relatively small amounts, when compared to the overall plant-in-service amount and overall distribution expenses, and showed that correcting the eight misclassifications and misallocations would have no effect on the results of the class study in the instant case. Great Plains agreed with the Department's recommended re-classifications and re-allocations, however, and agreed with the Department's recommendation to incorporate the changes in its next general rate case.[390]

C. Classification Methods for Distribution Mains (FERC Account 376) in the Record

1. Background

As to FERC Account No. 376, the Company proposed to classify all of its distribution mains as solely demand costs, which assumed that demand was the only factor that drives the

[386] Ex. DER-3 at 12 (Ouanes Direct).
[387] Electronic Code of Federal Regulations, Account 375.
[388] Ex. DER-3 at 13 (Ouanes Direct).
[389] *Id.* at 13-17.
[390] Ex. GP-26 at 17-18 (Hatzenbuhler Rebuttal); Ex. DER-11 at 1-3 (Ouanes Surrebuttal).

utility's investment in distribution mains. The Department disagreed with this classification because not only demand, but also, the number of customers drives investment in distribution mains. Dr. Ouanes' Direct Testimony explained his analysis and conclusion that Great Plains' distribution mains should be classified as both demand and customer costs.[391] He described how the distribution system exists to serve its two functions: 1) being capable of delivering service to customers' residences or businesses (customer costs), and 2) ensuring that the distribution system is large enough to provide reliable service (demand costs).[392]

In previous rate cases, Great Plains classified distribution mains as both demand and customer costs,[393] but in the instant case, Great Plains proposed to classify distribution mains as entirely demand costs due to data limitations. As its rationale, Great Plains stated:[394]

> Due to the data limitations previously discussed and the resulting inability to perform a minimum system study to the specifications set forth by the Commission, the Company opted to rely on the Basic Customer Method in its embedded class cost of service study. This was accomplished by utilizing a demand factor for the allocation of the distribution mains plant balance and utilizing a customer factor for only the services, meters, service regulators, and customer billing software rate base items.

2. Data Issues

Minnesota gas utilities generally use historical records for their distribution system including the amount of pipe laid, the size of pipe (diameter), the type of pipe (plastic or steel) and the book cost per foot of pipe for each type. The utility then inflates the costs of these projects using the Handy-Whitman (HW) Index of Public Utility Construction Costs to normalize the cost data in terms of current replacement costs.[395] Because the construction period

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[391] Ex. DER-3 at 18 (Ouanes Direct).
[392] *Id*. at 19.
[393] *Id*. at 22-23.
[394] *Id*. at 23.
[395] *Id*. at 28.

of the gas utilities' current distribution system covers several decades, equipment should be priced out at current replacement values to determine current unit replacement costs, not at original investment costs. This process provides for comparable current replacement investment values for each size and type of equipment.[396]

Dr. Ouanes identified several concerns with Great Plains' implementation of its minimum-size studies, including the lack of disaggregated data to provide for a meaningful minimum-size study, the fact that, in its studies, the Company regrouped all pipes sized less than two inches together, the Company's failure to include the available supporting data, the fact that, in one or both studies, the customer component was calculated based on: (1) a limited portion of footage of mains instead of all installed distribution mains, and/or (2) book cost data instead of current unit replacement costs.[397]

In his direct testimony, Dr. Ouanes recommended against approval of the two minimum-size methods initially filed by the Company, MS1 and MS2, and recommended that Great Plains provide in its rebuttal testimony an improved minimum size CCOSS.[398] He made this recommendation because, in response to discovery from the Department, the Company had provided an improved third minimum-size method study.[399] However, Great Plains' lack of detailed book cost data by type and size raised serious concerns about the reasonableness of the third study's calculated current unit replacement cost ($ per foot) of the installed distribution pipes, especially for the steel pipes. To address this issue, the Department requested that the Company file an improved minimum size method CCOSS, by using for each pipe type and size a

[396] *Id*.
[397] *Id*. at 30-32.
[398] *Id*. at 32-33.
[399] *Id*. at 30-32.

more reliable (potentially based on a supportable proxy) current unit replacement cost ($ per foot) of the installed distribution pipes.[400]

Great Plains did not complete a revised minimum-size method in response to the Department's recommendation. Instead, Mr. Hatzenbuhler stated in rebuttal testimony that:[401]

> the class cost of service study serves as a guide in the revenue allocation and rate design process and is generally not adhered to absolutely. As has been discussed, the Basic Customer Method class study that was utilized is useful if the analyst recognizes the effects of classifying distribution mains as entirely demand related. Because the Company is not proposing to bring the classes to anywhere near even the knowingly conservative results of the Basic Customer Method class study, I don't feel introducing an additional class study would be beneficial. This is especially true considering Great Plains, the Department and the OAG all agree the Company's proposed revenue allocation is reasonable and should be adopted. I appreciate Dr. Ouanes working with Great Plains to further understand the data limitations the Company faces when preparing minimum system studies and will take [sic] apply his suggestions when preparing the Company's next class study.

Because of the Company's current data limitations,[402] the Department concluded that there was no reasonably supported minimum-size study available in the record,[403] and, because all Basic Customer method CCOSSs, including the one Great Plains provided, classify distribution mains as entirely demand-related,[404] use of the results would need to respect the bias

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[400] Ex. DER-11 at 3-4 (Ouanes Surrebuttal).
[401] Ex. GP-26 at 18-19 (Hatzenbuhler Rebuttal); Ex. DER-11 at 4 (Ouanes Surrebuttal).
[402] The limitations appeared to have precluded Great Plains from providing and supporting a reliable current unit replacement cost ($ per foot) of the installed distribution pipes.
[403] Ex. DER-11 at 5 (Ouanes Surrebuttal).
[404] The classification of distribution mains as entirely demand-related results in costs being under-classified as customer-related and over-classified as demand-related. Moreover, according to the *Gas Rate Fundamentals* at 136, "fixed costs are usually assigned to the demand classification, except at the distribution level, where facilities are designed with the number and size of loads in mind." Ex. DER-3 at 25 (Ouanes Direct). Dr. Ouanes said he did not recommend approving the Basic Customer method CCOSS used by Great Plains because it relied on the incorrect assumption that demand is the only driver of Great Plains' investment in distribution mains, and therefore does not adequately reflect cost causation. Ex. DER-3 at 26 (Ouanes Direct).

inherent in those results.[405] The Department concluded that the Commission should not approve the Basic Customer method CCOSS,[406] nor the minimum-size methods and corresponding CCOSSs[407] in the record.

9. Rate Design and Apportionment of Revenue Responsibility

Customer Service Extension Tariff

Resolved between DER and GP: Great Plains and the Department agreed that the Company has generally applied its customer service extension tariff consistently and correctly.[408]

Revenue Apportionment

Resolved between DER and GP: Great Plains and the Department agreed that the Company's proposed changes to its revenue requirement apportionment based on its CCOSS and other ratemaking principles are reasonable.[409]

Basic Customer Service Charges

Resolved between DER and GP: Great Plains and the Department agreed that the Company's proposed increase to the basic customer charge for the residential and general firm class customers was reasonable.[410]

Disputed between DER and Great Plains: Great Plains proposed to increase the Large Interruptible Transportation and Interruptible Grain Drying basic customer service charges.[411] The Department recommended that the Commission approve smaller increases for both classes because the Company's proposals were inconsistent with the CCOSS. Great Plains subsequently accepted DER's recommendation for the

[405] Ex. DER-3 at 25 (Ouanes Direct); Ex. DER-11 at 5-6 (Ouanes Surrebuttal) (In addition, Basic Customer method CCOSSs under-estimates costs to be assigned to the Residential class while over-estimating costs to be assigned to the other classes: the demand allocator used (allocator number 2) assigns a lower portion of costs to the Residential class and a higher portion of costs to the other classes when compared to the customer allocator used (allocator number 4).
[406] Ex. DER-3 at 17-26 (Ouanes Direct); Ex. DER-11 at 6 (Ouanes Surrebuttal).
[407] Ex. DER-3 at 30-32 (Ouanes Direct).
[408] Ex. GP-31 at 16-24 (Bosch Direct); Ex. DER-4 at 3-21 (Zajicek Direct).
[409] Ex. GP-25 at 17-18 (Hatzenbuhler Direct); Ex. DER-4 at 40-48 (Zajicek Direct).
[410] Ex. GP-25 at 18-20 (Hatzenbuhler Direct); Ex. DER-4 at 51 (Zajicek Direct).
[411] Ex. GP-25 at 19-20 (Hatzenbuhler Direct).

Interruptible Grain Drying class.[412] The Company continues to dispute the Department's Large Interruptible Transportation class recommendation.[413]

Disputed between DER, Great Plains, and OAG: Great Plains and the Department agree that the proposed increase for residential and general firm class customers is reasonable.[414] The OAG recommends the Commission disallow any basic customer charge increases, including for the residential and general firm class customers.[415]

Basic Customer Charge Calculation

Disputed between DER and Great Plains: Great Plains proposed to calculate the residential and firm general rate basic service charge as a per-day rate as opposed to a monthly rate.[416] The Department recommended that the Commission reject this proposal because it creates little benefit while risking ratepayer confusion.[417]

Margin Sharing Proposal

Resolved between DER and GP: Great Plains and the Department agreed that the Company's proposed margin sharing mechanism to mitigate the risk of a single large customer ceasing to take service was reasonable.[418] Great Plains and the Department also agreed that DER's recommended compliance filings and sunset clause were appropriate.[419]

A. Great Plains' Customer Service Extension Tariff

The Commission's 90-563 ORDER directed the Department to evaluate Great Plains' customer service extension tariff in Great Plains' rate case proceeding.[420] As part of this analysis, the Commission directed DER to consider six questions.[421] Accordingly, the Department first evaluated Great Plains' free footage allowance that includes the majority of new

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[412] Ex. GP-26 at 3 (Hatzenbuhler Rebuttal).
[413] Ex. GP-26 at 4 (Hatzenbuhler Rebuttal).
[414] Ex. GP-25 at 18-20 (Hatzenbuhler Direct); Ex. DER-4 at 51 (Zajicek Direct).
[415] Ex. OAG-1 at 3 (Lebens Direct).
[416] Ex. GP-31 at 5-6 (Bosch Direct).
[417] Ex. DER-4 at 51 (Zajicek Direct).
[418] Ex. GP-25 at 14-15 (Hatzenbuhler Direct); Ex. DER-4 at 37-38 (Zajicek Direct).
[419] Ex. DER-4 at 38-40 (Zajicek Direct); Ex. GP-32 at 5 (Bosch Rebuttal).
[420] *In the Matter of an Inquiry into Competition Between Gas Utilities in Minnesota*, MPUC Docket No. G-999/CI-90-563, ORDER TERMINATING INVESTIGATION AND CLOSING DOCKET at 7 (90-563 ORDER) (Mar. 31, 1995).
[421] Ex. DER-4 at 7-8 (Zajicek Direct).

extensions with only the extremely long extensions requiring a customer contribution. DER witness Mr. Michael Zajicek concluded that the Company's extension procedures struck an appropriate balance by allowing most new customers to obtain extensions needed for service at reasonable rates, while not requiring existing customers to pay for unusually long service extensions.[422]

Second, the Department reviewed Great Plains methodology for determining the economic feasibility of service extension projects. Mr. Zajicek concluded that the Company's application of its Maximum Allowable Investment (MAI) policy to extension projects exceeding the free footage limit was reasonable.[423]

Third, the Department considered Great Plains' preference for a free footage allowance as opposed to a per-customer dollar allowance. Mr. Zajicek concluded that the Company's approach was reasonable, even if other approaches might be more accurate, because the free footage allowance is based on typical construction circumstance, easier for customers to understand, and administratively efficient to administer.[424]

Fourth, the Department evaluated whether Great Plains' extension charge refund policy is appropriate. The Company stated contributions for firm gas main extensions are refundable for a period of up to five years as additional customers are connected to the main for which the advance was made. Great Plains also explained that contributions for interruptible gas

[422] Ex. DER-4 at 10-12 (Zajicek Direct).
[423] Ex. DER-4 at 12 (Zajicek Direct).
[424] Ex. DER-4 at 13-14 (Zajicek Direct).

extensions are refundable for a period of up to five years in several circumstances.[425] Mr. Zajicek concluded that the Company's refund policy remains was reasonable.[426]

Fifth, the Department reviewed Great Plains' policy of not allowing customers to install their own service lines either independently or with the use of private contractors. The Company explained that allowing customers to install their own service lines would undermine the system's safety and reliability.[427] Mr. Zajicek concluded that Great Plains' policy was reasonable because the Company is responsible for the safe operation and maintenance of its service lines.[428]

Sixth, the Department considered Great Plains' policy of not providing financing to customers responsible for a service extension cost contribution. The Company stated it does not offer financing because of the additional risk associated with providing it.[429] Mr. Zajicek concluded that Great Plains' policy was reasonable and that private financing, such as from a bank, would still be available to customers.[430]

The 90-563 ORDER also directs DER to address three additional concerns. The first Commission concern is whether Great Plains is applying its tariffs correctly and consistently.[431] The Department reviewed customer service extensions between 2015 and 2018 and concluded that Great Plains is correctly applying its extension policy.[432] The second Commission concern is whether Great Plains' main and service line extensions are appropriately cost and load

[425] Ex. DER-4 at 14 (Zajicek Direct).
[426] Ex. DER-4 at 15 (Zajicek Direct).
[427] Ex. GP-31 at 19 (Bosch Direct).
[428] Ex. DER-4 at 15-16 (Zajicek Direct).
[429] Ex. GP-31 at 19-20 (Bosch Direct).
[430] Ex. DER-4 at 17 (Zajicek Direct).
[431] Ex. DER-4 at 17-18 (Zajicek Direct).
[432] Ex. DER-4 at 18 (Zajicek Direct).

justified. DER concluded that the Company's Maximum Allowable Investment policy is satisfactory.[433] The third Commission concern is whether Great Plains is including wasteful system additions in its rate base. The Department again concluded that the Company's MAI policy helps ensures that wasteful plant is not included in the Great Plains' rate base.[434]

Great Plains proposed two changes to its extension policies. First, the Company proposed to update the Levelized Annual Revenue Requirement (LARR) Factor to reflect changes to cost levels and capital structure that occur as a result of this proceeding. Second, Great Plains proposed to update its MAI calculation to reflect revenue associated with its Gas Utility Infrastructure Cost (GUIC) Rider adjustment and Margin Sharing Credit.[435] DER reviewed both proposals. The Department concluded both are reasonable as long as the LARR Factor and MAI calculation are updated to reflect the Commission's final decision relating to the Margin Sharing Credit and GUIC Rider revenues.[436]

B. Rate Design Principles

In the absence of market competition, utility rate setting must balance competing interests. First, the regulatory compact requires that rates provide the utility a reasonable opportunity to earn its revenue requirement.[437] Second, rates should promote efficient resource use.[438] Third, rates should encourage energy conservation and renewable energy use.[439] Fourth, rates should be understandable and simple to administer.[440] Fifth, rate changes should be gradual

[433] Ex. DER-4 at 19 (Zajicek Direct).
[434] Ex. DER-4 at 19-20 (Zajicek Direct).
[435] Ex. GP-31 at 24 (Bosch Direct).
[436] Ex. DER-4 at 20-21 (Zajicek Direct).
[437] Minn. Stat. § 216B.16, subd. 6 (2018).
[438] Minn. Stat. § 216B.04.
[439] Minn. Stat. §§ 216B.03 and 216C.05, subd. 1 (2018).
[440] Ex. DER-4 at 21-23 (Zajicek Direct).

to avoid ratepayer "rate shock."[441] Sixth, rates should not unreasonably discriminate against any particular customer class or against individual customers.[442] Finally, "[a]ny doubt as to reasonableness should be resolved in favor of the consumer."[443]

Two related rate design considerations are inter-class and intra-class subsidies. Inter-class subsidies occur when a customer class does not fully cover the costs of serving it with the difference made up by over-recovering costs from other classes. In contrast, intra-class subsidies typically occur when higher usage customers within a class subsidize other lower usage customers in the same class because the basic customer charge does not fully recover fixed costs.[444] These subsidies result in customer discrimination. However, efforts to limit these subsidies must be balanced against other ratemaking goals such as avoiding rate shock and administrative ease.

C. Great Plains' Proposed Revenue Apportionment is Reasonable

Based on its Class Cost of Service Study (CCOSS), Great Plains proposed to change how its revenue requirement is apportioned among its various customer classes. In particular, the Company proposed the following changes:

Class	Proposed Increase
Residential:	$1,593,949
Small Firm:	$989,237
Large Firm:	$99,390
IT Grain Drying:	$45,302
Small IT Sales:	$18,419
Large IT Sales:	$5,743
Large IT Transport:	$108,799
Total:	$2,860,839[445]

[441] Minn. Stat. § 216B.03.
[442] Minn. Stat. §§ 216B.03 and 216B.07.
[443] Minn. Stat. § 216B.03
[444] Ex. DER-4 at 51 (Zajicek Direct).
[445] Ex. GP-2, Schedule E-1 at 1-4 (Hatzenbuhler Direct).

Great Plains reasoned that the above apportionment would facilitate several ratemaking goals including "fairness of the specific rates in the apportionment of the total costs of service among the different consumers[.]"[446]

In its evaluation, the Department reviewed the Company's current, proposed, and CCOSS-based revenue apportionments.[447] Based on this evaluation, DER concluded that Great Plains' proposed revenue responsibility apportionment was reasonable because it "moves the majority of classes closer to the cost based apportionment of revenue responsibility, while leaving the remaining classes very close to the status quo."[448] The Department further reasoned that the risk of residential customer rate shock was abated by the fact that Great Plains' proposal only amounts to 55 percent of the increase suggested by the CCOSS.[449] Additionally, DER concluded that Great Plains' proposed revenue apportionment for interruptible customers was reasonable given that these customers have other fuel options available to them.[450]

D. Great Plains' Proposed Basic Customer Service Charges

Customer bills generally contain two types of charges. A volumetric charge based on the amount of natural gas used by the customer during the billing period. The amount recovered through the volumetric charge fluctuates based on usage level. Customer bills also contain a basic customer service charge that remains the same month to month. The basic customer service charge is intended to recover the utility's fixed costs that arise from making service available such as connecting a residence or business to the gas distribution system.[451]

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[446] Ex. GP-25 at 17-18 (Hatzenbuhler Direct).
[447] Ex. DER-4 at 42 (Zajicek Direct).
[448] Ex. DER-4 at 47 (Zajicek Direct).
[449] Ex. DER-4 at 47 (Zajicek Direct).
[450] Ex. DER-4 at 46 (Zajicek Direct).
[451] Ex. DER-4 at 51-52 (Zajicek Direct).

1. Residential and Firm Customer Basic Customer Charges

Great Plains proposed to increase the basic customer charge for the residential class by $1.50 a month, the small firm general class by $4.50 a month, and the large firm general service class by $6.50 a month.[452] The Company reasoned that these increases would move the residential and firm classes' basic customer charges closer to cost while not resulting in the rate shock that would accompany an increase in the basic customer charge fully to cost.[453] The Department evaluated Great Plains' proposal and determined that it would reduce intra-class subsidies by moving the majority of classes, including the residential and firm customer classes, closer to the costs identified in the CCOSS.[454] On this basis, Mr. Zajicek concluded the Company's proposed increases to the residential and general firm customer classes' basic customer charges were reasonable.

Additionally, Great Plains and the Department responded to OAG witness Mr. Lebens' argument that the residential and small business classes' basic customer service charge should remain unchanged. The OAG articulated three reasons why the basic customer charge should not be increased: (1) it discourages conservation; (2) it disproportionately impacts low-usage users; and (3) it is inconsistent with monopoly regulation principles.[455] The Department disagreed with each of these reasons. First, not increasing the customer charge would have marginal impact on conservation because the corresponding increase in volumetric charge would be small and natural gas is an inelastic commodity.[456] Second, the customer charge disproportionately impacts low-usage users, as suggested by Mr. Lebens, precisely because it is

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[452] Ex. GP-25 at 18-20 (Hatzenbuhler Direct); Ex. DER-4 at 46 (Zajicek Direct).
[453] Ex. GP-25 at 20 (Hatzenbuhler Direct).
[454] Ex. DER-4 at 51 (Zajicek Direct).
[455] Ex. OAG-1 at 3 (Lebens Direct).
[456] Ex. DER-8 at 2-3, 5-6 (Zajicek Rebuttal).

designed to ensure that low-usage customers pay their fair share of fixed service costs. DER further concluded that a basic customer charge that accurately reflects fixed costs may benefit low-income customers because these customers may use slightly more energy on average than other customers due to older housing and other circumstances.[457] Third, monopoly regulation is intended to prevent utilities from asserting monopoly power. It is not intended to unreasonably restrict how utilities collect payment. Moreover, fixed delivery charges are used by a variety of competitive market firms, such as furniture stores, hardware stores, and grocery stores, to collect fixed expenses. In Great Plains' case, the basic customer charge is intended to recover the fixed expenses associated with connecting the customer's premise to safe, reliable service regardless of the natural gas consumed.[458] For these reasons, the Department rejected Mr. Lebens' argument and recommended that the Commission approve Great Plains' proposed increases to the residential and general service customer classes.[459]

2. Large Interruptible Transportation Class and Interruptible Grain Drying Class Basic Customer Charges

Great Plains proposed to increase the Large Interruptible Transportation Service Rate class' basic customer service charge to $560 per month, amounting to an increase of $300 per month. The Company further proposed increasing the Interruptible Grain Drying Service Rate class' basic customer service charge by $350 to $450 per month.[460] These significant increases are inconsistent with the ratemaking principle that changes should be gradual to avoid "rate shock" to ratepayers. These increases also exceed the basic charge recommended by Great Plains' Class Cost of Service Study (CCOSS) and thereby exacerbate intra-class

457 Ex. DER-8 at 8-9 (Zajicek Rebuttal).
458 Ex. DER-8 at 6-8 (Zajicek Rebuttal).
459 Ex. DER-8 at 9 (Zajicek Rebuttal).
460 Ex. GP-25 at 19-20 (Hatzenbuhler Direct).

subsidies.[461] For these reasons, Great Plains' Large Interruptible Transportation Service and Interruptible Grain Drying Service Rate classes' customer service charge increases are unreasonable. To avoid these outcomes, the Large Interruptible Transportation class' customer charge and the Interruptible Grain Drying class' customer charge should both be set at $400. Mr. Zajicek noted that these charges would more closely match the customer charges recommended by the CCOSS results.[462]

Great Plains' rebuttal argument, that a basic customer service of $560 per month is justified by high fixed demand costs, is unpersuasive.[463] Demand costs are typically recovered through the volumetric charge not the basic customer charge. Accordingly, it makes little sense to increase the basic customer charge to account for high fixed demand costs.[464]

Great Plains subsequently accepted the Department's recommendation that the Interruptible Grain Drying Service Rate class' basic customer service charge be set at $400.[465] While the Company did not agree to DER's Large Interruptible Transportation Service Rate recommendation, Great Plains stated that if the Commission adopted the Department's recommendation, then the Large Interruptible Sales Service Rate class' basic customer charge should be similarly adjusted downwards to $355.[466] The Company reasoned that this adjustment would maintain the existing relationship between the Large Interruptible Transportation and Large Interruptible Sales rates. The Department responded that it would be reasonable to maintain this relationship, as described in Mr. Hatzenbuhler's rebuttal testimony, in the event the

[461] Ex. DER-4 at 49 (Zajicek Direct).
[462] Ex. DER-4 at 53 (Zajicek Direct).
[463] Ex. GP-26 at 4 (Hatzenbuhler Rebuttal).
[464] Ex. DER-12 at 3 (Zajicek Surrebuttal).
[465] Ex. GP-26 at 3 (Hatzenbuhler Rebuttal).
[466] Ex. GP-26 at 4 (Hatzenbuhler Rebuttal).

Commission adopts a $400 basic customer charge for the Interruptible Transportation Service Rate.[467]

3. Great Plains' Proposed Basic Customer Charge Calculation Change is Unreasonable

Additionally, Great Plains proposed to calculate the residential and firm general service classes' basic service charge as a per-day rate as opposed to a monthly rate.[468] However, a basic rate design principle is that rates should be understandable for ratepayers and easy to administer. The Company's proposal unreasonably risks customer confusion by allowing the basic customer charge to fluctuate with the length of the month.[469] The switch also would have little financial impact for Great Plains; namely, because the Company appears to have simply taken the monthly rate and applied a prorated daily rate over the entire year. Since the proposal creates little benefit while risking ratepayer confusion, the Department concludes that the proposal is unreasonable and recommends that the Commission reject it.[470]

E. Great Plains' Margin Sharing Proposal is Reasonable

The NOTICE OF AND ORDER FOR HEARING (Nov. 22, 2019) requested that the parties develop a record on whether the proposed margin sharing mechanism should be incorporated into the Revenue Decoupling Mechanism (RDM). Great Plains' proposed margin sharing mechanism was developed by allocating the Company's revenue deficiency to the various customer classes, with the resulting amounts allocated to the margin sharing customer set aside and referred to as the "Target Margin Sharing Increase."[471] The Target Margin Sharing Increase was then allocated to the non-margin sharing customer classes. Finally, under the proposal,

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[467] Ex. DER-12 at 6 (Zajicek Surrebuttal).
[468] Ex. GP-31 at 5-6 (Bosch Direct).
[469] Ex. DER-4 at 50 (Zajicek Direct).
[470] Ex. DER-4 at 51 (Zajicek Direct).
[471] Ex. GP-25 at 14-15 (Hatzenbuhler Direct).

revenue would be collected from the margin sharing customer at the Large Interruptible Transport Class rate and credited back to the other customers.[472] Great Plains explained that the purpose of this mechanism is to avoid the need for an immediate rate case in the event that the margin sharing customer ceases to take service.[473] In the event that the margin sharing customer ceases service, the credit would no longer be applied to the other customer bills. To implement the margin sharing proposal, the Company proposed that it be incorporated into its Revenue Decoupling Mechanism (RDM).[474]

The Department concluded that Great Plains' proposal was reasonable for several reasons. First, the proposal is symmetrical. In addition to bearing the risks, the other customers would enjoy a larger-than-proposed credit if the margin sharing customer increases usage above the level estimated in this proceeding.[475] Second, if the margin sharing customer does cease or reduce service, the margin sharing mechanism would allocate costs to other customers consistent with the rate design approved in this rate case.[476] Third, the proposal does not discriminate against other customer classes and could avoid the expenses of a rate case.[477]

DER did however recommend that the Commission require Great Plains to make an annual compliance filing and impose a sunset clause on the mechanism. The Department also recommended that Great Plains explain how the margin sharing mechanism would operate in the event the RDM did not continue beyond 2021.[478] Great Plains subsequently agreed to DER's

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472 Ex. GP-25 at 15 (Hatzenbuhler Direct).
473 Ex. GP-25 at 15 (Hatzenbuhler Direct).
474 Ex. GP-31 at 10-11 (Bosch Direct).
475 Ex. DER-4 at 37 (Zajicek Direct).
476 Ex. DER-4 at 37 (Zajicek Direct).
477 Ex. DER-4 at 38 (Zajicek Direct).
478 Ex. DER-4 at 38-40 (Zajicek Direct).

compliance filing and sunset clause recommendations.[479] The Company also explained how the margin sharing mechanism could operate in the RDM's absence and by what authority the Commission could approve it.[480] Mr. Zajicek found this explanation to be adequate and concluded "the Company's proposal to administer the [Margin Sharing Credit] in the RDM is reasonable for the time being."[481] For these reasons, Great Plains' margin sharing mechanism proposal is reasonable.

10. REVENUE DECOUPLING MECHANISM

RDM Extension

Resolved between DER and GP: DER and GP agreed that the Commission should approve operation of the Company's revenue decoupling mechanism through December 31, 2021.[482]

Large Interruptible Customers

Resolved between DER and GP: DER and GP also agreed that the Commission should approve GP's proposal to remove its large interruptible customers from its revenue decoupling mechanism, starting January 1, 2021.[483]

Minimum Energy Savings Threshold

Resolved between DER and GP: DER and GP agreed that it is not necessary for the Commission to set a minimum energy savings threshold that GP must meet before implementing its revenue decoupling mechanism surcharge.[484]

A. Introduction

Revenue decoupling is "a regulatory tool designed to separate a utility's revenue from changes in energy sales. The purpose of revenue decoupling is to reduce a utility's disincentive

[479] Ex. GP-32 at 5 (Bosch Rebuttal).
[480] Ex. GP-32 at 5-9 (Bosch Rebuttal).
[481] Ex. DER-8 at 7 (Zajicek Surrebuttal).
[482] Ex. DER-5 at 18 (Davis Direct); Ex. GP-26 at 9 (Hatzenbuhler Rebuttal).
[483] Ex. GP-25 at 25 (Hatzenbuhler Direct); Ex. DER-5 at 21 (Davis Direct); Ex. GP-26 at 11-12 (Hatzenbuhler Rebuttal).
[484] Ex. GP-25 at 27-28 (Hatzenbuhler Direct); Ex. DER-5 at 20 (Davis Direct); Ex. GP-29 at 3-4 (Fischer Rebuttal).

to promote energy efficiency."[485] A revenue decoupling mechanism (RDM) allows the utility to recover differences between actual and forecasted base class revenue responsibility.[486] The Commission first approved Great Plains' RDM as a three-year pilot program in the Company's 2015 rate case.[487] The Company's RDM became effective on January 1, 2017. Without Commission action, Great Plains' RDM would have expired on December 31, 2019. However, the Company sought and obtained a one-year extension from the Commission.[488]

A. Great Plains Accepted DER's Recommendation to Evaluate Extension of the Revenue Decoupling Mechanism After December 31, 2021.

In this proceeding, Great Plains proposed to extend its RDM pilot program indefinitely. The Company reasoned that continuation of the RDM better aligned its business objectives with state conservation goals and customer preferences.[489] The Department evaluated Great Plains' proposal and concluded that any extension decision should be made after December 31, 2021 to allow an evaluation of the Company's 2019 and 2020 CIP achievements.[490] The Department noted that Great Plains' energy conservation savings results had increased significantly immediately before the RDM's implementation and had decreased during the RDM pilot period. Specifically, DER witness Mr. Christopher Davis calculated that "Great Plains' average annual first-year Dk savings post-RDM . . . were 38 percent lower than the Company's annual first-year Dk savings pre-RDM[.]"[491]

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[485] Minn. Stat. § 216B.2412, subd. 2 (2018).
[486] Ex. DER-5 at 2 (Davis Direct).
[487] GREAT PLAINS 2015 RATE CASE ORDER at 40–43, 56.
[488] *In the Matter of the Request of Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for a One-Year Extension of Revenue Decoupling Pilot Program*, MPUC Docket No. G-004/M-19-198, ORDER at 1 (Jan. 13, 2020).
[489] Ex. GP-25 at 24 (Hatzenbuhler Direct).
[490] Ex. DER-5 at 18 (Davis Direct).
[491] Ex. DER-5 at 14 (Davis Direct).

In response, Great Plains indicated it was unclear whether Mr. Davis was recommending approval of the RDM through December 31, 2020 or December 31, 2021. However, the Company stated that it did not object to deferring the RDM extension decision until after December 31, 2021, assuming that was DER's recommendation.[492] Mr. Davis' surrebuttal testimony confirmed that Great Plains correctly understood the Department's recommendation that the RDM extension decision be deferred until after December 31, 2021.[493]

B. Great Plains' Proposal to Remove Large Interruptible Class from the RDM Beginning in 2021 is Reasonable

Great Plains also proposed to remove the Large Interruptible Rate Class from the RDM. The Company explained that it only has seven Large Interruptible Class customers and that a significant size disparity exists between the largest and smallest class members. As a result, if a larger class member were to cease service, the RDM would have an outsized impact on the remaining small class members.[494] Great Plains also proposed that these customers should be removed from the RDM beginning in 2021 because it would be after the initial three-year period expired, but before the one-year extension began.[495]

The Department concluded Great Plains' proposal to remove Large Interruptible Class customers from the RDM was reasonable for three reasons. First, DER consulted with a third-party expert who suggested a minimum threshold of ten customers. Second, the OAG similarly had proposed a minimum threshold of fifty customers in prior rate cases. Third, the Commission had imposed a fifty customer threshold in Minnesota Energy Resources Corporation's 2015 rate

[492] Ex. GP-26 at 9-10 (Hatzenbuhler Rebuttal).
[493] Ex. DER-13 at 2 (Davis Surrebuttal).
[494] Ex. GP-25 at 24-26 (Hatzenbuhler Direct).
[495] Ex. GP-26 at 11 (Hatzenbuhler Rebuttal).

case.[496] Accordingly, the Department agreed it would be reasonable to exclude Great Plains' seven large interruptible customers from the RDM beginning in 2021.[497]

C. Great Plains and DER Agree That a Minimum Savings Threshold is Not Necessary

The Commission's NOTICE OF AND ORDER FOR HEARING directed the parties to consider whether a minimum energy savings level be required in order to implement a RDM surcharge.[498] In response, Great Plains cited three reasons that RDM surcharges should not be directly connected to minimum energy savings. First, the Company suggested that its energy savings are affected by factors outside of its control.[499] Second, Great Plains believes that "[m]aking the end result, achievement of the goal, a prerequisite to being allowed to administer one of the tools put in place specifically to help achieve that goal is backwards."[500] Third, the Company believes the surcharge restriction penalizes Great Plain because the minimum savings threshold "only limits the ability to surcharge customers and not the ability to refund[.]"[501]

The Department agreed with the Company's conclusion that it was not necessary for the Commission to impose a minimum energy savings threshold as this time. However, DER relied on different reasons. Mr. Davis noted that the Commission had declined to impose minimum savings thresholds in past rate cases. Additionally, the Commission will have an opportunity to

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[496] Ex. DER-5 at 21-22 (Davis Direct); *see also In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, MPUC Docket No. G-011/GR-15-736 (MERC 2015 Rate Case), FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 45 (Oct. 31, 2016).
[497] Ex. DER-13 at 3 (Davis Surrebuttal).
[498] NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 22, 2019).
[499] Ex. GP-25 at 27 (Hatzenbuhler Direct).
[500] Ex. GP-26 at 12 (Hatzenbuhler Rebuttal).
[501] Ex. GP-25 at 27 (Hatzenbuhler Direct).

consider the minimum savings issue again in 2021 when it determines whether to continue the RDM going forward.[502]

However, in the event the Commission chooses to implement a minimum savings threshold, the Department stated that a minimum savings threshold of 13,000 dekatherms would be reasonable. Mr. Davis reasoned that 13,000 dekatherms would be appropriate because it is "4 percent lower than the lowest level of energy savings Great Plains achieved between 2013 and 2018."[503] In response, Great Plains witness Mr. Jeremy J. Fischer stated, "if a minimum energy-savings threshold were to be set prior to the Commission's evaluation of whether Great Plains' RDM should continue beyond 2021, it should be no more than 13,000 Dk for the reasons laid out by Mr. Davis."[504]

CONCLUSION

The Department respectfully requests a recommendation from the ALJ and an Order from the Commission, determining that the rates filed by Great Plains have not been shown to be just and reasonable, as required by Minn. Stat. § 216B.16, subd. 5 (2016), for the reasons discussed in this Initial Brief. The Department requests that the Commission establish reasonable rates that

[502] Ex. DER-5 at 19-20 (Davis Direct).
[503] Ex. DER-5 at 20 (Davis Direct).
[504] Ex. GP-29 at 3-4 (Fischer Rebuttal).

are consistent with the principles, analyses, and recommendations, as addressed in the Department's testimony and this Initial Brief.

Dated: April 10, 2020

Respectfully submitted,

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APPENDIX A: PROCEDURAL HISTORY OF DOCKET 19-511

- On August 27, 2019, Great Plains filed sales forecast data with the Commission, 30 days in advance of its petition for a general rate case, as was required by the Commission's order in the Company's last general rate case.[505]

- On September 27, 2019, the Company filed a general rate case petition requesting a $2,849,686 increase in Minnesota natural gas rates, or an approximately 12.0 percent overall increase, effective January 1, 2020, based on a forecasted 2020 test year[506] and a proposed 10.2 percent rate of return on equity.[507] The Company also proposed a $2,600,907 interim rate increase, or an approximately 10.98 percent increase, effective January 1, 2020, in the event the Commission elected to suspend the proposed rates.[508] The return on equity for the interim rate proposal was 9.06 percent.[509]

- On October 1, 2019, the Commission issued a notice requesting initial comments by October 7, 2019 with reply comments due by October 14, 2019 on two issues. The first issue was whether Great Plains' petition complied with the filing requirements of Minn. Stat. § 216B.16 (2018), Minn. R. 7825.3100 – .4400 (2019), and relevant Commission orders. The second issue was whether this matter should be sent to the Office of Administrative Hearings (OAH) for an evidentiary hearing on the proposed rate change.[510]

- On October 3, 2019 and October 7, 2019, respectively, the Department and the OAG filed comments. The Department recommended that the Commission accept Great Plains' rate case filing in the present docket as complete and refer this matter to the OAH.[511] The OAG recommended that the Commission require Great Plains to assign all ratepayers a proportionate share of the interim revenue deficiency and remove organizational dues expenses from interim rates that were disallowed in the last rate case.[512]

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[505] *In the Matter of the Petition by Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-004/GR-15-879, Findings of Fact, Conclusions, and Order at 52 (Sept. 6, 2016) (GREAT PLAINS 2015 RATE CASE ORDER).
[506] Ex. GP-21 at 5 (Jacobson Direct); Ex. GP-1, Great Plains Volume III, Statement A (Jurisdictional Financial Summary) (Sept. 27, 2019).
[507] Ex. GP-14 at 109 (Bulkley Direct).
[508] Petition for Interim Rates at 3-4 (Sept. 27, 2019).
[509] *Id*. at 3.
[510] NOTICE OF COMMENT PERIOD ON COMPLETENESS AND PROCEDURES at 1 (Oct. 1, 2019).
[511] Initial Comments of the Department at 2 (Oct. 7, 2019).
[512] Initial Comments of the OAG at 4 (Oct. 7, 2019).

- On October 14, 2019, the Company agreed that the case should be referred to the OAH and that previously disallowed organizational dues should be removed from interim rates.[513] Additionally, Great Plains disagreed with the OAG's recommendation that flexible tariff rate customers be assigned a share of interim rates.[514]

- During the agenda meeting on November 7, 2019, the Commission considered whether to accept the Company's petition as complete, suspend the proposed rates, refer the matter to the OAH, and set interim rates as requested.[515]

- On November 22, 2019, the Commission issued three orders in the present docket. First, the Commission accepted the Company's filing as complete as of September 27, 2019, suspended the proposed final rates, and extended the suspension period until August 26, 2020.[516] Second, the Commission authorized Great Plains to implement interim rates, but denied its request to recover forgone flexible rate customer interim revenue from its remaining customers.[517] Third, the Commission referred the matter to the OAH for contested case proceedings and directed the Company to notify customers of the evidentiary and public hearings.[518]

- On December 18, 2019, the matter came before Administrative Law Judge (ALJ) Ann C. O'Reilly for a prehearing conference to discuss time frames, scheduling, discovery procedures, and similar issues.

- On January 9, 2020, the Commission considered, and on January 13, 2020 issued an order relating to a request filed by Great Plains on September 6, 2019 in the *Great Plains 2015 Rate Case* and a related *Extension Docket* as follows:[519] (1) approving a one-year extension to Great Plains' pilot full Revenue Decoupling Mechanism (RDM) Rider (which had been first approved as a three-year pilot program in the *Great Plains 2015 Rate Case*[520]*)* (2) directing Great Plains to

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[513] Reply Comments of Great Plains at 1–2 (Oct. 14, 2019).
[514] *Id.* at 2–4.
[515] NOTICE OF COMMISSION MEETING at 2 (Oct. 25, 2019).
[516] ORDER ACCEPTING FILING, SUSPENDING RATES, AND EXTENDING TIMELINE at 2 (Nov. 22, 2019).
[517] ORDER SETTING INTERIM RATES at 4 (Nov. 22, 2019).
[518] NOTICE OF AND ORDER FOR HEARING at 5–6 (Nov. 22, 2019).
[519] *In the Matter of the Application of Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-004/GR-15-879 (*Great Plains 2015 Rate Case*) and *In the Matter of the Request of Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for a One-Year Extension of Revenue Decoupling Pilot Program,* Docket No. G-004/M-19-198 (*Extension Docket*), ORDER (Jan. 13, 2020).
[520] Great Plains' first full RDM became effective on January 1, 2017, and was scheduled to end on December 31, 2019.

update its tariff sheets to reflect the extension, and (3) agreeing with and adopting the recommendations of the Department, which were attached and incorporated into the order.

- On January 6, 2020, ALJ O'Reilly issued the First Prehearing Order that set procedures and established a schedule for the case.

- On January 13, 2020, an amended First Prehearing Order was issued to clarify the schedule for the case, as shown below:

DATE	**EVENT**	**DESCRIPTION**
January 10, 2020	Intervention Deadline	All petitions for intervention shall be served and filed by this date.
January 16, 2020	Direct Testimony Due	Direct testimony shall be served and filed by this date
February 11, 2020	Rebuttal Testimony Due	All rebuttal testimony shall be served and filed by this date.
February 24, 2020	Public Hearings: 11:00 a.m. in Marshall 6:00 p.m. in Fergus Falls	Public hearings will be held at: Marshall-Lyon County Library 201 C Street, Marshall, MN National Guard Armory 421 E. Cecil Avenue Fergus Falls, MN
March 3, 2020	Surrebuttal Testimony Due	All surrebuttal testimony shall be served and filed by this date.
March 3, 2020	Close of Public Comment Period	All public comments must be eFiled or receive by the Commission on this date.
March 4, 2020	Settlement Conference 10:00 a.m.	All parties and participants shall appear for an in-person settlement conference pursuant to Minn. Stat. § 216B.16, subd. 1a (2018).
March 6, 2020	Service and Filing of Proposed Witness Lists, Proposed Exhibit Lists, and Proposed Exhibits	By 4:30 p.m., the parties shall serve and file, in the eDockets system, their proposed witness lists, proposed witness lists, and proposed exhibits. Proposed exhibit lists shall be clearly named and filed as: "[Party Name's] Proposed Exhibit List."
March 10 – 11, 2020	Evidentiary Hearing 9:30 a.m.	An evidentiary hearing will be held in the large conference room of the Public Utilities Commission in St. Paul, MN, commencing at 9:30 a.m. each day.

March 26, 2020	Applicant's Proposed Issue Matrix to be Circulation	Applicant shall circulate among the parties its proposed Issue Matrix for review and revision by the parties. The Issue Matrix should plainly state the subject of the dispute without background, editorializing, or argument. The Issue Matrix shall also list the testimony on each dispute.
April 10, 2020	Final Issue Matrix Due	The parties shall jointly file a final Issues Matrix identifying the issues in the dispute and the evidence addressing such issues. The parties shall work together to create a single Issue Matrix for the Judge.
April 10, 2020	Initial Briefs Due	By 4:30 p.m., the parties shall serve and file their Initial Briefs.
April 24, 2020	Responsive Briefs and Proposed Findings Due	By 4:30 p.m., the parties shall serve and file their Response Briefs and Proposed Findings.
June 30, 2020	Administrative Law Judge's Report Due	The Judge shall file her Findings of Fact, Conclusions of Law, and Recommendation.
July 15, 2020	Exceptions Due	By 4:30 p.m., the parties shall serve and file their Exceptions to the Administrative Law Judge's Report.
September 18, 2020 (anticipated)	Commission Decision Due	The Commission shall issue its decision on or before September 18, 2020.

- On January 10, 2020, the OAG filed a petition to intervene.

- On January 16, 2020, the Department and OAG filed direct testimony.

- On January 22, 2020, the DOC DER requested minor revisions to the Amended First Prehearing Order.

- On January 24, 2020, the ALJ issued the Second Prehearing Order granting the OAG full party status, acknowledging that the Commission named DER as a party to this proceeding in its November 22, 2019 Notice of and Order for Hearing, and making minor revisions to the First Prehearing Order.

- On February 11, 2020, Great Plains and DER filed rebuttal testimony.

- On February 20, 2020, the Commission filed a notice of public hearings.

- On February 24, 2020, two public hearings were held – an afternoon hearing in Marshall, Minnesota and an evening hearing in Fergus Falls, Minnesota. One member of the public attended the hearing in Marshall and commented regarding the Company's proposed twelve percent residential rate increase.

- On March 3, 2020, the Department and OAG filed surrebuttal testimony.

- On March 4, 2020, the ALJ held a prehearing settlement conference pursuant to Minn. Stat. § 216B.16, subd. 1a (2018). During the conference, the Company and the Department reached resolutions of certain previously unresolved issues.

- On March 9, 2020, the Company filed a "Motion to Include Limited New Information in the Record of Great Plains Natural Gas Co."

- On March 10, 2020 the Department filed a "Motion to Deny Great Plains' Motion and Exclude Certain Portions of Ann E. Bulkley's Witness Summary Statement," together with a letter motion for Department Witness Craig Addonizio to respond to Ms. Bulkley's Witness Summary.

- On March 10, 2020, the ALJ held an evidentiary hearing at the Commission's offices in St. Paul, Minnesota.[521] During the proceedings the ALJ determined to grant the motion of Great Plains, admit Ann E. Bulkley's Witness Summary, including the new information, and to hold open the evidentiary record to permit Mr. Addonizio to file a response of up to three pages in length, to which no further response was permitted.[522]

- On March 12, 2020, the Department filed Mr. Addonizio's Response to Ms. Bulkley's Summary Statement.[523]

- On March 30, 2020, the Parties filed a Joint Issues Matrix.

- On April 10, 2020, the Department, Company and OAG filed initial briefs.

- On April ___, 2020, the Department, Company and OAG filed stipulated proposed findings regarding issues that had been resolved prior to the evidentiary hearing.

- On April 24, 2020, the Department, Company and OAG served and filed their response briefs and proposed findings on issues that were not resolved prior to the evidentiary hearing.

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[521] Evidentiary Hearing Transcript Volume (Tr. Vol.).
[522] Tr. Vol. at 8-32.
[523] Ex. DER-23 (Addonizio Response to GP Witness Ann E. Bulkley's Summary Statement).

CERTIFICATE OF SERVICE

Re: ***In the Matter of the Petition by Great Plains Natural Gas Company, a Division of Montana-Dakota Utilities, Co., for Authority to Increase Natural Gas Rates in Minnesota***
OAH Docket No. 65-2500-36528; MPUC Docket No. G004/GR-19-511

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I, Ann Kirlin, hereby state that on April 10, 2020, I filed by electronic eDockets the attached Initial Post-Hearing Brief of the Minnesota Department of Commerce, Division of Energy Resources, and eServed or sent by US Mail, as noted, to all parties on the attached service list.

See attached service list.

/s/ Ann Kirlin
ANN KIRLIN

SERVICE LIST

Electronic Service Member(s)

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