OAH 82-2500-32997
MPUC G-004/GR-15-879

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

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

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION

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An evidentiary hearing was held before Administrative Law Judge Barbara J. Case on April 7, 2016, pursuant to a Notice and Order for Hearing filed by the Public Utilities Commission (Commission) with the Office of Administrative Hearings on November 30, 2015. Public hearings were held in Marshall and Fergus Falls on March 9, 2016. Written public comments were received until March 21, 2016.

Post-hearing briefs were filed by the parties on May 6, 2016. The record closed on May 20, 2016 upon submission of the parties' reply briefs and proposed Findings.

Appearances:

Brian M. Meloy, Stinson Leonard Street L.L.P., represents Great Plains Natural Gas (Great Plains).

Julia E. Anderson and Peter E. Madsen, Assistant Attorneys General, represent the DOC-DER of Commerce, Division of Energy Resources (DOC-DER).

Joseph A. Dammel and Ryan P. Barlow, Assistant Attorneys General, represent the Office of the Attorney General, Residential Utilities and Antitrust Division (OAG).

Dorothy Morrissey, Bob Brill, Sundra Bender, Robert Harding, Ganesh Krishnan, and Ann Schwieger participated as Commission staff.

STATEMENT OF THE ISSUES

The Commission directed the parties to establish an evidentiary record regarding the following issues:

1. Is the test year revenue increase sought by Great Plains reasonable or will it result in an unreasonable and excessive earnings by Great Plains?

2. Is the rate design proposed by Great Plains reasonable?

3. Are Great Plains' proposed capital structure and return on equity reasonable?

4. Should Great Plains consolidate the separate base costs of gas from its North and South Districts into one unified base cost of gas rate – and if so, how?

5. Should Great Plains change how it recovers and credits its demand-related gas costs – and if so, how?

6. Should Great Plains recover its Unamortized Loss on Debt and related deferred taxes in rate base – and if so, how?[1]

FINDINGS OF FACT

I. THE PARTIES

1. Great Plains provides natural gas to approximately 21,400 customers in 18 Minnesota communities, operating over 460 miles of distribution mains and 390 miles of service lines.[2] Great Plains' customer base is 85 percent residential customers and 15 percent commercial and industrial customers.[3]

2. Great Plains is owned by Great Plains MDU Resources Group Inc. (MDU).[4] MDU, located in Bismarck, North Dakota, is a publicly traded company with a diverse range of nationwide subsidiaries, including electric and natural gas utilities as well as construction companies.[5] Total revenues for MDU in 2014 were $4.7 billion.[6]

3. Great Plains shares personnel and facilities with Montana-Dakota Utilities Co., another subsidiary of MDU.[7] Montana-Dakota Utilities Co. provides regulated gas and electric service in Montana, North Dakota, South Dakota, and Wyoming.[8]

4. The DOC-DER represents the public interest in rate proceedings. The DOC-DER's staff reviews the testimony and schedules filed by the utility and other parties to assure their accuracy and completeness, and files testimony and argument addressing the reasonableness of the elements of the rate request.

5. The OAG represents the interests of residential and small business customers in proceedings before the Commission. The OAG staff reviews the

[1] NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 30, 2015) (eDocket No. 201511-115997-01).
[2] Ex. 9 at 2 (Kivisto Direct).
[3] *Id.*
[4] Exhibit (Ex.) 100 at 3 (Lindell Direct). All of the exhibits received as part of the record during this proceeding are set forth in a master exhibit list. *See* MASTER EXHIBIT LIST (Apr. 18, 2016) (eDocket No. 20164-120-217-01).
[5] Ex. 100 at 3 (Lindell Direct).
[6] *Id.*
[7] *Id.*
[8] *Id.*

testimony and schedules filed by Great Plains and other parties and files testimony and argument intended to protect the interests of the customers it represents.

II. THE APPLICATION

6. In this case, Great Plains projects a test year revenue deficiency of $1,578,942 based on its projected 2016 operating income and rate base plus an overall rate of return of 7.696 percent.[9] Great Plains is requesting an increase in natural gas rates of $1,578,615.[10]

7. Great Plains claims a rate increase is needed primarily to cover its increased investment in the facilities necessary to safely and reliably serve customers, which also increases depreciation, operation and maintenance expenses and taxes.[11] Since filing its last case in 2005, Great Plains has invested in an automated meter reading system, a customer billing system, a mobile dispatch system, and a compliance monitoring system. At the same time, customers are using less natural gas on average.[12]

8. On September 30, 2015, Great Plains filed an application with the Commission requesting authority to increase its natural gas rates in Minnesota.[13] Great Plains is seeking an annual rate increase of $1,578,942 and an overall rate of return of 7.696 percent.[14] As part of its initial filing, Great Plains requested an interim rate increase of $1,534,823 effective on January 1, 2016.[15] Great Plains also filed Direct Testimony as part of its initial filing.[16]

9. On October 2, 2015, the Commission issued a notice to potentially interested parties requesting comments regarding whether Great Plains' application should be accepted as substantially complete and the case referred to the Office of Administrative Hearings.[17] The DOC-DER and the OAG submitted comments in response to the Commission's notice.[18]

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[9] Ex. 19 at 4 (Jacobson Direct).
[10] Ex. 9 at 5 (Kivisto Direct).
[11] *Id.* at 6.
[12] *Id.* at 6-7.
[13] *See* APPLICATION (Sept. 30, 2015) (eDocket No. 20159-114434-01).
[14] Ex. 19 at 4 (Jacobson Direct).
[15] *Id.* at 23.
[16] Ex. 9 (Kivisto Direct); Ex. 10 (Darras Direct); Ex. 11 (Kaiser Direct); Ex. 12 (Senger Direct); Ex. 14 (Gaske Direct); Ex. 17 (McCullough Direct); Ex. 19 (Jacobson Direct); Ex. 24 (Morman Direct); Ex. 25 (Aberle Direct).
[17] NOTICE OF COMMENT PERIOD ON COMPLETENESS AND PROCEDURES (Oct. 2, 2015) (eDocket No. 201510-114544-01).
[18] Comment by DOC-DER (Oct. 12, 2015) (eDocket No. 201510-114757-01); Reply Comment by DOC-DER (Oct. 20, 2015) (201510-114966-01); Comment by OAG (Nov. 2, 2015) (eDocket No. 201511-115349-01).

III. PROCEDURAL BACKGROUND

10. On October 12 and 20, 2015, the DOC-DER submitted comments recommending that the Commission accept Great Plains' filing as complete and refer the matter to the Office of Administrative Hearings for contested case proceedings.[19]

11. On November 2, 2015, the OAG filed comments objecting to Great Plains' proposed interim rates.[20]

12. On November 17, 2015, Great Plains filed updated base cost of gas information, and revised interim rates to remove the Unamortized Loss on Debt and associated deferred income taxes from the revenue deficiency calculation for interim rates in compliance with the Commission's directives at its November 13, 2015 Agenda Meeting.[21]

13. On November 30, 2015, the Commission issued its Order Accepting Filing, Suspending Rates, Extending Timelines, and Requiring Supplemental Filings in which it accepted Great Plains' application as substantially complete as of September 30, 2015, and extended statutory timelines applicable to the rate case to August 31, 2016.[22]

14. Also on November 30, 2015, the Commission issued its Order Setting Interim Rates, authorizing Great Plains to implement interim rates for service rendered on and after November 30, 2015, granting Great Plains' request to waive its right to put interim rates into effect on November 30, 2015, and authorizing Great Plains to implement interim rates for service rendered on and after January 1, 2016.[23]

15. Also on November 30, 2015, the Commission issued a Notice and Order for Hearing referring Great Plains' application to the Office of Administrative Hearings for a contested case proceeding and directing Great Plains to file supplementary direct testimony and exhibits by January 4, 2016, including updated 2015 Rate Base and Operating Statement numbers based on actual 2015 data through October 31, 2015, and revised projected data for the balance of 2015.[24]

16. Great Plains, the DOC-DER, and the OAG were the only parties to this matter when it was referred to the Office of Administrative Hearings.[25] No petitions for intervention were filed.

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[19] Comment by DOC-DER (Oct. 12, 2015) (eDocket No. 201510-114757-01); Reply Comment by DOC-DER (Oct. 20, 2015) (201510-114966-01).
[20] Comment by OAG (Nov. 2, 2015) (eDocket No. 201511-115349-01).
[21] Ex. 8 (Update to Base Cost of Gas).
[22] ORDER ACCEPTING FILING, SUSPENDING RATES, EXTENDING TIMELINES, AND REQUIRING SUPPLEMENTAL FILINGS at 3 (Nov. 30, 2015) (eDocket No. 201511-115996-01).
[23] ORDER SETTING INTERIM RATES at 5-6 (Nov. 30, 2015) (eDocket No. 201511-115995-01).
[24] NOTICE AND ORDER FOR HEARING at 6 (Nov. 30, 2015) (eDocket 201511-115997-01).
[25] *Id.* at 4.

17. On December 28, 2015, a prehearing conference was held at the Commission's office in Saint Paul.[26] On January 4, 2016, the Administrative Law Judge issued the First Prehearing Order setting forth procedures and a schedule for this proceeding.[27]

18. On January 4, 2016, Great Plains filed its Supplementary Filing – Updated 2015 Information and Supplementary Direct Testimony in accordance with the Commission's November 30, 2015 Notice and Order for Hearing in this proceeding.[28]

19. On January 28, 2016, the Administrative Law Judge issued a Protective Order regulating the use and disclosure of nonpublic data in this proceeding.[29]

20. On February 23, 2016, the OAG and the DOC-DER filed Direct Testimony.[30]

21. Public hearings were held on March 9, 2016, in Marshall and Fergus Falls.[31]

22. On March 21, 2016, the Administrative Law Judge issued the Second Prehearing Order providing call-in information for the April 6, 2016 telephone conference.[32]

23. On March 21, 2016, the parties filed Rebuttal Testimony.[33]

24. On April 4, 2016, the parties filed Surrebuttal Testimony.[34]

25. Another prehearing conference was held via telephone on April 6, 2016, to finalize plans for the evidentiary hearing.[35]

26. The evidentiary hearing was held on April 7, 2016, at the Commission's office in Saint Paul.[36]

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[26] FIRST PREHEARING CONFERENCE TRANSCRIPT (Feb. 4, 2016) (eDocket No. 20162-117989-01).
[27] FIRST PREHEARING ORDER (Jan. 4, 2016) (eDocket No. 20161-116925-01).
[28] Ex. 21 (Updated 2015 Information).
[29] PROTECTIVE ORDER (Jan. 28, 2016) (eDocket No. 20161-117757-01).
[30] Ex. 100 (Lindell Direct); Ex. 200 (Johnson Direct); Ex. 204 (Addonizio Direct); Ex. 206 (Otis Direct); Ex. 209 (Ruzycki Direct); Ex. 211 (Heinen Direct); Ex. 215 (Lusti Direct).
[31] PUBLIC HEARING TRANSCRIPT (Mar. 22, 2016) (eDocket No. 20163-119326-01).
[32] SECOND PREHEARING ORDER (March 21, 2016) (eDocket No. 20163-119299-01).
[33] Ex. 15 (Gaske Rebuttal); Ex. 18 (McCullough Rebuttal); Ex. 22 (Jacobson Rebuttal); Ex. 26 (Aberle Rebuttal); Ex. 101 (Lindell Rebuttal); Ex. 202 (Johnson Rebuttal); Ex. 207 (Otis Rebuttal).
[34] Ex. 28 (Aberle Surrebuttal); Ex. 102 (Lindell Surrebuttal); Ex. 203 (Johnson Surrebuttal); Ex. 205 (Addonizio Surrebuttal); Ex. 208 (Otis Surrebuttal); Ex. 210 (Ouanes Surrebuttal); Ex. 213 (Heinen Surrebuttal); Ex. 216 (Lusti Surrebuttal).
[35] SECOND PREHEARING CONFERENCE TRANSCRIPT (Apr. 18, 2016) (eDocket No. 20164-120216-91).
[36] EVIDENTIARY HEARING TRANSCRIPT (Apr. 18, 2016) (eDocket No. 20164-120216-02).

27. On April 22, 2016, Great Plains filed its Issue Matrix.[37]

28. On May 6, 2016, the parties submitted Initial Briefs.[38]

29. On May 20, 2016, the parties submitted Reply Briefs and Proposed Findings of Fact.[39]

30. The record closed on May 20, 2016.

IV. PUBLIC COMMENTS

A. Public Hearings

31. The Commission directed Great Plains to give notice of the public hearings to all current customers, affected municipalities, counties, and other local governing bodies, and all parties involved in its last two rate cases. The Commission also directed Great Plains to place advertisements for public hearings in newspapers in the affected counties as well as in newspapers of general circulation in its service area.[40]

32. Two hearing notices were written and disseminated: one for the North District and one for the South District.[41] Both notices, titled "Rate Increase Notice," set forth information on the public hearings.[42] The notices were reviewed and approved by the Administrative Law Judge prior to dissemination.[43]

33. The notice for the North District stated the amount of the requested increase as $1,578,615, or approximately 6.4 percent per year. The notice also explained that the requested increase would add about $2.27 to a typical residential Great Plains North District customer's monthly bill.[44]

34. The notice for the South District also stated the amount of the requested increase as $1,578,615, or approximately 6.4 percent per year. The notice explained that the requested increase would add about $5.83 to a typical Residential Great Plains South District customer's monthly bill.[45]

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[37] ISSUES MATRIX (eDocket No. 20164-120536-01).
[38] Great Plains Initial Post-Hearing Brief (Br.) (May 6, 2016) (eDocket No. 20165-121131-02); DOC-DER Initial Post-Hearing Br. (May 6, 2016) (eDocket No. 20165-121122-02); OAG Initial Post-Hearing Br. (May 6, 2016) (eDocket No. 20165-121129-01).
[39] Great Plains Reply Br. (May 20, 2016) (eDocket No. 20165-121528-02); DOC-DER Reply Br. (May 20, 2016) (eDocket No. 20165-121530-01); OAG Reply Br. (May 20, 2016) (eDocket No. 20165-121542-01).
[40] NOTICE OF AND ORDER FOR HEARING at 6 (Nov. 30, 2015) (eDocket No. 201511-115997-01).
[41] APPROVAL OF PUBLIC HEARING NOTICE at 3-8 (Jan. 25, 2016) (eDocket No. 20161-117615-01).
[42] *Id.*
[43] *Id.* at 1.
[44] *Id.* at 3-5.
[45] *Id.* at 6-8.

35. Two public hearings regarding Great Plains' proposed rate increase were held on March 9, 2016.

1. Marshall Public Hearing

36. The first public hearing was held on March 9, 2016, in the morning at the Lyon County Library in Marshall, Minnesota. Travis Jacobson, Jordan Hatzenbuhler, and Tamie Aberle attended the Marshall public hearing on behalf of Great Plains. Ann Schwieger attended the Marshall public hearing on behalf of the Commission. Joseph Dammel attended the Marshall public hearing on behalf of the OAG. Dale Lusti attend the Marshall public hearing on behalf of the DOC-DER.

37. No members of the public attended the Marshall public hearing. The Administrative Law Judge convened the hearing at 11:30 a.m. and closed the hearing at 11:53 a.m.[46] The Administrative Law Judge noted for the record that no impediments to public participation, such as bad weather or facility issues, were apparent.[47]

2. Fergus Falls Public Hearing

38. The second public hearing was held on March 9, 2016, in the evening at the City Council Chambers in Fergus Falls, Minnesota. Travis Jacobson, Jordan Hatzenbuhler, and Tamie Aberle attended the Fergus Falls public hearing on behalf of Great Plains. Ann Schwieger attended the Fergus Falls public hearing on behalf of the Commission. Joseph Dammel attended the Fergus Falls public hearing on behalf of the OAG. Zac Ruzycki attend the Fergus Falls public hearing on behalf of the DOC-DER.

39. Several presentations were made at the outset of the Fergus Falls public hearing. First, Ann Schwieger provided information on the Commission's process for reviewing and approving the rate increase request.[48] Second, Jordan Hatzenbuhler, Travis Jacobson, and Tamie Aberle presented information on Great Plains and the reasons behind the rate increase request.[49] Third, Joseph Dammel provided information on OAG's position on the rate increase request by Great Plains.[50] And lastly, Zac Ruzycki provided information on the DOC-DER's involvement in the process.[51]

40. Three members of the public attended the Fergus Falls public hearing and all three spoke on the record during the hearing.[52] All speakers were afforded a full

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[46] Public Hearing Transcript (Tr.) at 7 (Mar. 9, 2016).
[47] *Id.* at 6.
[48] *Id.* at 14.
[49] *Id.* at 15-28.
[50] *Id.* at 29-31.
[51] *Id.* at 31-33.
[52] *See* PUBLIC HEARING SIGN IN SHEET (Mar. 22, 2016) (eDocket No. 20163-119325-01).

opportunity to make a statement on the record and to ask questions. A transcript of the public hearing was filed by the designated court reporter on March 22, 2016.[53]

41. The three members of the public asked questions directed to Great Plains addressing: the base rate;[54] the conservation improvement program;[55] Great Plains revenue during the past ten years;[56] employee retention;[57] apportioning rates by geographic (North and South) Districts;[58] affiliations with other utility providers;[59] and the possibility of recouping the costs of a gas extension.[60]

42. Two members of the public, Ron Haus and Mike Streeter, stated on the record that the rate increase request by Great Plains should not be approved by the Commission, citing concerns about Great Plains' profits and its ability to control costs.[61]

B. Written Comments

43. Three members of the public filed written comments using the SpeakUp platform on the Commission's website.

44. On February 13, 2016, Nick Klisch submitted a written comment opposing the rate increase request by Great Plains.[62] Mr. Klisch believes the requested rate increase is "not purely to cover distribution charges" but instead "a way to try and justify increased revenue."[63] Mr. Klisch points to the increased availability of natural gas in recent years and calls "a 6.4 percent overall rate increase insane."[64]

45. On March 14, 2016, Erik Cherveny submitted a written comment also opposing the rate increase request by Great Plains.[65] Mr. Cherveny claims "services from Great Plains have dropped and become poor and outsourced," and wishes "there was another service provider" from which to choose.[66] Mr. Cherveny also argues that "families and communities are being stressed with increases across the board financially" and a rate increase will add to the struggle.[67]

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[53] *See* PUBLIC HEARING TRANSCRIPT (Mar. 22, 2016) (eDocket No. 20163-119236-01).
[54] Public Hearing Tr. at 37-39 (Mar. 9, 2016) (Haus).
[55] *Id.* at 42-45 (Streeter).
[56] *Id.* at 47-52.
[57] *Id.* at 52-53.
[58] *Id.* at 53-55.
[59] Public Hearing Tr. at 57 (Mar. 9, 2016) (Streeter).
[60] Public Hearing Tr. at 61-62 (Mar. 9, 2016) (Hed).
[61] Public Hearing Tr. at 60, 63-64 (Mar. 9, 2016) (Streeter, Haus).
[62] Comment by Nick Klisch (Feb. 13, 2016) (SpeakUp) (eDocket No. 20163-119389-01).
[63] *Id.*
[64] *Id.*
[65] Comment by Erik Cherveny (Mar. 14, 2016) (SpeakUp) (eDocket No. 20163-119389-01).
[66] *Id.*
[67] *Id.*

46. On March 21, 2016, Bob Heinert submitted a written comment also opposing the rate increase request by Great Plains.[68] Mr. Heinert believes Minnesota customers should be receiving a refund or decreased rates because "[a]s a subsidiary of the big stock market[,] MDU resources, Bismarck, gets North Dakota nat[ural] gas that is so cheap they just burn it off to get rid of it at the well."[69] Mr. Heinert asserts that companies should be responsible for the costs of their own infrastructure and not pass the cost on to consumers.[70]

V. LEGAL STANDARDS

47. The Commission must set rates that are just and reasonable, balancing the interests of the utility and its customers.[71] A reasonable rate enables a utility not only to recover its operating expenses, depreciation, and taxes, but also allows it to compete for funds in the capital market. Minnesota law recognizes this principle when it defines a fair rate of return as the rate which, when multiplied by the rate base, will give a utility a reasonable return on its total investment.[72]

48. The utility seeking an increase in its rates has the burden of proving by a preponderance of the evidence that its proposed change will result in just and reasonable rates.[73] This standard applies both in a traditional rate case and when a utility has proposed a multi-year rate plan.[74]

49. In the context of a rate proceeding, the "preponderance of the evidence" is defined as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory duty to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[75] Any doubt as to reasonableness of the proposed rates is to be resolved in favor of the consumer.[76]

50. The Commission acts in both a quasi-judicial and quasi-legislative capacity in setting rates. On purely factual issues, the Commission acts in its quasi-judicial capacity. On issues involving policy judgment, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.[77]

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[68] Comment by Bob Heinert (Mar. 21, 2016) (SpeakUp) (eDocket No. 20163-119389-01).
[69] *Id.*
[70] *Id.*
[71] Minn. Stat. § 216B.03 (2014).
[72] Minn. Stat. § 216B.16, subd. 6 (2014).
[73] Minn. Stat. § 216B.16, subds. 4, 19(a) (2014).
[74] *Id.*
[75] *In re Northern States Power Co.,* 416 N.W.2d 719, 722 (Minn. 1987).
[76] Minn. Stat. § 216B.03.
[77] *St. Paul Chamber of Commerce v. Minn. Pub. Utilities Comm'n*, 251 N.W.2d 350, 356-57 (Minn. 1977).

VI. REVENUE REQUIREMENT ISSUES INTRODUCTION

51. The revenue requirement portion of a rate case seeks to determine what additional revenue is required to meet the utility's required operating income, based upon a "test year" of operations. The required operating income is derived from determining the amount of investments in the rate base that have been made by a utility's shareholders, and multiplying the approved rate base times the rate of return that is determined to be appropriate for Great Plains.

52. After determining the required operating income, Great Plains' test year expenses and revenues are evaluated to determine the current operating income for the test year. The difference between the required operating income and the test year operating income is the income deficiency. The income deficiency is converted into a gross revenue deficiency amount.

53. Great Plains' proposed test year period is calendar year 2016. Great Plains developed its test year based on the calendar year 2014 as its base year and made adjustments and projections for 2015 and 2016 to its proposed test year costs.[78]

54. The Commission ordered Great Plains to provide additional support for its 2016 test year by supplementing Great Plains' 2015 financial data with actual 2015 financial data through October 2015. The updated actual data allows for an "accuracy check" on the projections made in the initial filing.[79]

55. In its 2015 Update, filed on January 4, 2016, Great Plains used a forecasted test year representing the 12 months ending December 31, 2016.[80] Development of the 2016 test year began with 2014 calendar year actual results and then included adjustments and projections for 2015 and 2016 to produce its test year costs.[81]

56. Great Plains provided a 2015 Update of rate base projections showing a reduction in their previous projection by $212,888 or 1.6 percent.[82]

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[78] Ex. 100 at 3 (Lindell Direct).
[79] NOTICE OF AND ORDER FOR HEARING at 6 (Nov. 30, 2015) (eDocket No. 201511-115997-01).
[80] Ex. 200 at 4 (Johnson Direct).
[81] Ex. 100 at 3 (Lindell Direct); Ex. 215 at 3 (Lusti Direct).
[82] Ex. 21 at 2 (Jacobson Direct Supplement).

VII. REVENUE REQUIREMENT RESOLVED ISSUES

During the course of this proceeding, the parties resolved certain financial issues that were previously in dispute.

A. Labor

57. Great Plains' initially proposed labor expenses of $2,778,208. In supplemental testimony, it decreased the amount by $41,900 to $2,736,308.[83]

58. The OAG originally recommended a reduction to the test year labor expense of $41,900 based on the reduction in labor expense between Great Plains' projected labor expenses included in its application and the updated actual 2015 expense.[84]

59. The OAG subsequently agreed the amount is part of the General Operation and Maintenance Expense adjustment proposed by the OAG and withdrew its recommendation for a test year labor expense adjustment.[85]

B. Nonqualified Pension Expense

60. Mr. Mark Johnson, witness for the DOC-DER, testified that under the Internal Revenue Code, employees whose earnings are above the qualified IRS limit receive a non-qualified pension benefit for the pay that is above the IRS limit.[86]

61. Non-qualified pension expenses are sometimes referred to as supplemental executive retirement plan costs or benefit restoration costs. The Commission has a history of denying recovery from ratepayers of these types of costs.[87]

62. Great Plains has confirmed that it did not include any non-qualified pension expenses in the test year.[88]

C. Unamortized Loss on Debt Repurchased

63. In this proceeding, the Commission asked the parties to investigate whether Great Plains should be authorized to recover its unamortized loss on debt and related deferred taxes in the rate base, and if so, how.[89]

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83 Ex. 100 at 7 (Lindell Direct).
84 *Id.*
85 Ex. 102 at 2-3 (Lindell Surrebuttal).
86 Ex. 200 at 15 (Johnson Direct) (citing 26 U.S.C. §§ 401(a)(17), 415(b)(1)(A) (2012)).
87 Ex. 200 at 15–16 (Johnson Direct); Ex. 202 at 5 (Johnson Rebuttal).
88 Ex. 202, MAJ-R-2 at 1 (Johnson Rebuttal).
89 NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 30, 2015) (eDocket No. 201511-115997-01).

64. Great Plains included an unamortized loss on debt repurchased balance of $69,520 in its 2016 test year rate base, along with an offsetting balance to accumulated deferred income tax of $25,773.[90] Great Plains explained that the unamortized loss is related to three pollution control bonds issued June 1, 1992, with a maturity date of June 1, 2022.[91]

65. Mr. Travis Jacobson, a witness for Great Plains, explained that when Great Plains reacquires debt in order to reduce debt costs, the unamortized loss is then amortized over the remaining life of the new issuance. Customers benefit through the net lower cost of debt, and it is proper to include the cost of achieving the savings through the inclusion of the unamortized balance on the loss on debt in rate base.[92]

66. The DOC-DER evaluated Great Plains' proposal to include its unamortized loss on debt repurchased and related accumulated deferred income taxes in the test year rate base and did not oppose it.[93] The DOC-DER agrees that Great Plains' decision to repurchase debt provided a benefit to ratepayers.[94]

67. In addition, the DOC-DER did not oppose Great Plains' proposal to treat the associated amortization expense in a manner similar to Great Plains' amortization of other debt discount and expense, which is reflected in Great Plains' cost of long-term debt and overall cost of capital.[95]

68. The Administrative Law Judge agrees that the record supports approval of Great Plains' proposals noted above.

D. Deferred Taxes

69. Most utilities, including Great Plains, use tax normalization for ratemaking purposes.[96] Therefore, a utility's deferred income tax should not be removed from its test year income statement.[97]

70. The DOC-DER concluded that Great Plains properly followed tax normalization procedures when it included its total tax expense (current and deferred income tax expense) on its test year income statement and recorded an offsetting entry for deferred income tax expense to accumulated deferred income taxes in the test year rate base.[98]

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[90] Ex. 2, Schedule B-3 at 6 (Application).
[91] Ex. 200, MAJ-5 at 1 (Johnson Direct).
[92] Ex. 19 at 7 (Jacobson Direct).
[93] Ex. 200 at 17–21 (Johnson Direct).
[94] *Id.* at 18.
[95] Ex. 200 at 21 (Johnson Direct).
[96] *Id.*
[97] *Id.*
[98] *Id.* at 23.

E. Bonus Depreciation

71. An article from the Edison Electric Institute explains that:

> [T]he book or regulatory treatment of a utility asset may differ from the tax treatment of the asset under the Internal Revenue Code. Utilities account for depreciation of their assets through both regulatory depreciation and tax depreciation. Regulatory depreciation generally spreads the cost of utility property ratably over its useful life so that the cost is borne equally by both current and future customers who will benefit from the property. Tax law allows a Great Plains to accelerate depreciation allowances.[99]

72. Mr. Johnson, a witness for the DOC-DER, explained that bonus depreciation allows for faster depreciation of assets for tax purposes than would normally be permitted under the Internal Revenue Code.[100] The federal Protecting Americans from Tax Hikes (PATH) Act of 2015 extends bonus depreciation through 2019.[101]

73. The DOC-DER confirmed that Great Plains did not incorporate the effects of the PATH Act in its test year tax calculations and record an offsetting entry to accumulated deferred income taxes.[102]

74. The DOC-DER agreed with Great Plains that if extended bonus depreciation under the PATH Act was incorporated in test year tax calculations, there would be no impact on the test year income statement.[103] Because the offsetting entry to deferred income tax expense is recorded in the rate base, the DOC-DER agreed that the impact resulting from the election of bonus depreciation becomes important.[104]

75. The DOC-DER also agreed with Great Plains that its test year income statement shows a net taxable loss of $53,206, which would become even larger if book (regulatory) depreciation was substituted with tax depreciation.[105] According to Mr. Johnson, ratemaking requires the use of book (regulatory) depreciation for tax normalization purposes.[106]

76. Additional tax depreciation under the PATH Act in the 2016 test year would increase Great Plains' deferred tax liability and, at the same time, create a deferred tax asset of equal value if Great Plains was in a net operating loss (NOL) carry-forward position.[107] A NOL carry-forward position means the utility carries the

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[99] *Id.* at 22.
[100] *Id.* at 23.
[101] *Id.*
[102] Ex. 203 at 9 (Johnson Surrebuttal).
[103] *Id.* at 10.
[104] *Id.*
[105] *Id.*
[106] *Id.*
[107] *Id.* at 11.

amount forward for twenty years to apply against any taxable income, which reduces the amount of taxable income in those years.[108]

77. Great Plains confirmed that it will be in an NOL carry-forward position during the 2016 test year and does not expect to elect bonus depreciation. As a result, the DOC-DER concluded that an adjustment to the rate case is not necessary.[109]

78. The DOC-DER also recommended the Commission require Great Plains to submit a compliance filing showing whether or not Great Plains followed through on its intention not to elect bonus depreciation.[110]

79. The Administrative Law Judge recommends that the Commission require Great Plains to submit the compliance filing requested by the DOC-DER.

F. Interest Synchronization

80. Interest synchronization is used for ratemaking in order to determine the amount of interest expense to be used in the calculation of test year income tax.[111]

81. The DOC-DER recommended a reduction to the test year federal and state income tax. The adjustment results from the application of interest synchronization to the DOC-DER's recommended test year rate base.[112]

82. Great Plains did not offer rebuttal to the proposed adjustment or its calculation.[113]

83. The Administrative Law Judge agrees that the adjustment is reasonable.

G. Base Cost of Gas Adjustment

84. The DOC-DER recommends the test year sales, Cost of Gas, Other Operation and Maintenance, and other categories, be adjusted to reflect the differences associated with the change in the Base Cost of Gas. The net effect of the adjustment is a slight increase in operating income.[114]

85. The Administrative Law Judge agrees the adjustment is reasonable.

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[108] *Id.*
[109] Ex. 218 at 1, 3 (Johnson Summary).
[110] *Id.* at 1.
[111] Ex. 215 at 14 (Lusti Direct).
[112] Ex. 216, DVL-S-7 (Lusti Surrebuttal).
[113] Evidentiary Hearing Tr. at 45-46 (Jacobson).
[114] Ex. 215, DVL-8 (Lusti Direct).

VIII. DISPUTED EXPENSE AND COST ISSUES

A. Pension Expense

86. The issue of pension expenses is disputed between Great Plains, the OAG, and the DOC-DER.

87. Great Plains has defined benefit pension plans for both union and non-union employees, which were closed to new entrants as of January 1, 2006. Both the union and non-union pension plans have been frozen since December 31, 2011 (union) and December 31, 2009 (non-union).[115] Based on a test year representing 12 months ending December 31, 2016, Great Plains included $11,292 of projected pension expense in the test year income statement on a Minnesota jurisdictional basis.[116]

88. Great Plains' pension expense calculations include assumptions such as the measurement date, the discount rate, and long-term growth rate. A summary of Great Plains' historical and projected pension expense along with their assumptions is provided in the table below[117]:

Table 1: GP Pension Expense and Assumptions

	Pension Expense (MN)	Discount Rate	L.T. Growth Rate	Measurement Date
2011 Actual	$13,586	5.20%-5.36%	7.75%	12/31/10
2012 Actual	($6,469)	4.11%-4.25%	7.75%	12/31/11
2013 Actual	$16,320	3.59%-3.66%	7.00%	12/31/12
2014 Actual	$4,979	4.48%-4.53%	7.00%	12/31/13
2015 Projected	$11,021	3.67%-3.71%	7.00%	12/31/14
2016 Projected	$11,292	3.44%-3.49%	6.75%	12/31/15

89. Pension expense calculations are done at a specific point in time and can vary significantly from year to year.[118] As a result, it is important to ensure that a utility uses a reasonable discount rate and long-term growth rate to determine a reasonably representative level of pension expense.[119]

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[115] Ex. 200, MAJ-3 at 2 (Johnson Direct).
[116] Ex. 2, Schedule C-2 at 10 (Application).
[117] Ex. 200 at 8 (Johnson Direct).
[118] *Id.* at 9.
[119] *Id.*

90. Great Plains' actual pension expense has varied significantly over the years, from a low of negative ($6,469) in 2012 to a high of $16,320 in 2013.[120]

91. Great Plains' projected test year pension expense of $11,292 is significantly higher than its 2014 actual pension expense of $4,979, the last year in which actual expenses are shown in the record.[121]

92. Great Plains' 2015 update filed on January 4, 2016, indicated an estimated 2015 pension expense of $14,672, an increase of $3,651 from the $11,021 filed in the original Application.[122]

93. Great Plains' 2016 test year pension expense was based on actuarial projections.[123]

94. The OAG witness, Mr. John Lindell, recommended a reduction to the pension expense because of the increase from $4,979 in 2014 to $11,292 for the 2016 test year, which he characterized as a dramatic increase. Mr. Lindell asserted that the test year level of $11,292 was not justified that given Great Plains' historical level of pension expense has fluctuated between ($6,469) in 2012 to $16,320 in 2013.[124]

95. Mr. Lindell recommended a normalized pension expense amount of $7,401, resulting in a reduction of $3,891 to the test year amount included by Great Plains.[125]

96. Great Plains argues that Mr. Lindell's recommended reduction is unsupported because the 2015 Update indicated its pension expense increased by $3,651 from the $11,021 filed in the original filing.[126] According to Great Plains, the pension increase for the test year was attributable to its adoption of new mortality tables and also the use of lower discount rates to calculate the expense.[127]

97. Moreover, Great Plains notes that the pension adjustment is based on the most current information from its actuary as well as ongoing expenses rather than events in prior years.[128]

[120] Ex. 200, MAJ-4 at 1 (Johnson Direct).
[121] *Id.*
[122] Ex. 22 at 10-11 (Jacobson Rebuttal).
[123] Ex. 200 at 8 (Johnson Direct).
[124] Ex. 100 at 8-9 (Lindell Direct).
[125] *Id.*
[126] Ex. 22 at 10-11 (Jacobson Rebuttal).
[127] Ex. 100 at 9 (Lindell Direct).
[128] Ex. 23 at 3 (Jacobson Testimony Summary).

98. The DOC-DER believes that Great Plains failed to demonstrate the reasonableness of two assumptions underpinning the proposed test year pension expense: the assumed discount rate and the long-term growth rate.[129]

99. The DOC-DER argues that Great Plains did not demonstrate the reasonableness of the two assumptions because Great Plains' assumed discount rate is too low for ratemaking purposes, and Great Plains' long-term growth rate may also be too low.[130]

100. According to the DOC-DER, Great Plains' assumptions about these two factors would result in rates charged to ratepayers that are unreasonably high since the rates would overcharge ratepayers for Great Plains' pension costs.

101. As a general matter, the lower the assumed discount rate, the higher the pension expense calculation. Great Plains' actual discount rates have ranged from a high of 5.20 percent to 5.36 percent in 2011 to a low of 3.59 percent to 3.66 percent in 2013. Great Plains' estimated discount rates decreased from 4.48 percent to 4.53 percent actuals in 2014 to 3.67 percent to 3.71 percent in 2015, and are even lower for the test year (2016), at 3.44 percent to 3.49 percent.[131]

102. Because the DOC-DER concluded that Great Plains' proposed test year pension expenses is unreasonably high, the DOC-DER asked Great Plains to re-calculate its test year pension expense by: 1) using a measurement date of December 31, 2015; 2) using discount rates of 4.21 percent to 4.30 percent; and 3) using a long-term growth rate of 6.75 percent.[132]

103. The DOC-DER's assumptions are based on a five-year historical average of Great Plains' actual discount rates and Great Plains' proposed long-term growth rate, which is the same method approved by the Commission in other rate case proceedings.[133]

104. Great Plains did not agree to re-run its calculations based upon the assumptions suggested by the DOC-DER because Great Plains believed the cost to do so would be unreasonable in light of the overall pension expense amount at issue.[134]

105. The DOC-DER accepted Great Plains' refusal to not re-run its calculations, and instead examined other alternatives to estimating a reasonable level of the test year pension expense in rates.[135]

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[129] Ex. 200 at 9-11 (Johnson Direct).
[130] *Id.*
[131] *Id.*
[132] Ex. 200 at 14 (Johnson Direct).
[133] *Id.*
[134] Ex. 22 at 4 (Jacobson Rebuttal).
[135] Ex. 202 at 3 (Johnson Rebuttal).

106. The OAG recommended a normalized level of test year pension expenses based upon the average level of pension expense for the last five years of actual data (2010 to 2014).[136] Normalization is a common ratemaking tool used when an expense varies significantly over the years.[137]

107. Great Plains' 2015 update for pension expense is not an actual expense figure, but still includes forecasted data and is outside of the five-year average of actual data that the DOC-DER used, from 2010 to 2014, to calculate the five-year average. Therefore, according the DOC-DER the soundest approach is to set the test year pension expense on Great Plains' average and actual annual pension expenses for calendar years 2010 to 2014.[138]

108. For these reasons, the DOC-DER concluded that in this case, the use of a five-year average of annual pension expense is a reasonable method to determine the test year pension expense.[139]

109. Both the DOC-DER and the OAG proposed a decrease to Great Plains' test year pension expense of $3,891, asserting that the pension expense should be based on Great Plains' average annual pension expense for calendar years 2010 to 2014 (five-year average), which totals $7,401 on a Minnesota jurisdictional basis.[140]

110. The Administrative Law Judge agrees that the OAG's and the DOC-DER's recommended adjustment is reasonable and recommends its adoption by the Commission.[141]

B. General Operation and Maintenance (O&M) Expenses

111. Great Plains proposed $6,095,020 for O&M expenses for the 2016 test year.[142] The DOC-DER does not dispute this amount. However, the OAG recommends a reduction of $123,384 in 2016 O&M expenses.

112. In its application, Great Plains projected a 2015 O&M expense of $5,754,053, which was used to develop the 2016 test year expense.[143]

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[136] Ex. 100 at 9 (Lindell Direct).
[137] Ex. 202 at 4 (Johnson Rebuttal).
[138] Ex. 203 at 6 (Johnson Surrebuttal).
[139] *Id.*
[140] Ex. 100 at 9 (Lindell Direct); Ex. 203 at 6 (Johnson Surrebuttal).
[141] Great Plains also argues that the record shows the OAG's proposed pension adjustment is duplicative of its proposed general O&M expense adjustment as evidenced by questions asked of Mr. Lindell during the evidentiary hearing. This issue is addressed below in the O&M expenses section.
[142] Ex. 2, Statement C at 2 (Application).
[143] Ex. 2, Statement C at 2 (Application).

113. On January 4, 2016, Great Plains submitted an updated 2015 projection based on its actual expenses from January to October 2015 and estimates for November and December 2015.[144] The updated O&M projection is $5,629,217.[145]

114. The OAG recommends a $123,384 decrease in O&M expenses for the 2016 test year, based on the difference between the original and updated O&M cost projections for 2015.[146]

115. Great Plains and the OAG address labor costs, medical and dental benefits, and pension expenses as elements of general O&M expenses. The parties do not further itemize the remainder of the O&M expenses included in the 2016 test year amount.

116. Great Plains and the OAG agree that certain labor costs should be removed from the test year O&M expense because these costs were overestimated by $41,900 in the original 2015 projection.

117. The OAG's proposed reduction includes $33,650 for decreased medical and dental expenses.[147] However, as discussed further in the section titled Medical/Dental Expenses, the Administrative Law Judge concludes that the 2016 test year expenses for medical and dental benefits based on the original 2015 projections are reasonable and no adjustment is necessary for medical and dental expenses. Therefore, $33,650 (the difference between the original projected medical and dental benefits and the updated projected medical and dental benefits) should not be included in any adjustment to the 2016 test year expense based on updated O&M expenses.

118. In addition, Great Plains argues that OAG double-counted pension costs because the OAG sought reduction of the expenses individually and also as part of the general O&M expenses.[148] No double counting occurred because the pension reduction discussed above was based on a normalization of pension expenses and that reduction is not reflected in the updated 2015 pension expense.

119. As for the remaining O&M expenses included in the test year, but which are not further broken down by the parties, Great Plains bears the burden of proving the reasonableness of its expenses. Great Plains has failed to clearly support its assertion that the remainder of its 2016 test year O&M expenses are reasonable, despite the OAG's contention that the 2015 update is more accurate for predicting 2016 test year expenses. Therefore, with the exception of $33,650 in medical and dental costs, Great Plains has failed to demonstrate that the $123,384 reduction in O&M expenses proposed by the OAG is not reasonable. Therefore, Administrative Law Judge

[144] Ex. 21, TRJ-4 at 1 (Jacobson Direct Supplement).
[145] *Id.*
[146] OAG Initial Post-Hearing Br. at 6-7.
[147] *See* Ex. 2, C-2 at 10 (Application); Ex. 21, TRJ-4 at 17 (Jacobson Direct Supplement).
[148] Great Plains Initial Br. at 47-48.

recommends an $89,734 reduction ($123,384-$33,650=$89,734) in general O&M expenses for the 2016 test year.

C. Rate Case Expenses

120. Great Plains' application includes an adjustment for rate-case expenses necessary to prepare and file this rate case, including consultant and legal fees as well as administrative costs and billings from the Office of Administrative Hearings, the DOC-DER, and the Commission. The DOC-DER does not challenge Great Plains' estimate of the expenses it expects to incur in this proceeding, but rather questions the reasonableness of the amortization period.[149]

121. Great Plains proposes amortizing rate case expenses over a three-year period, which is based on the length of time it expects the rates authorized by this proceeding to be in place.[150] Great Plains position is based, in large part, on its upcoming capital expenditures.

122. Great Plains' witness, Ms. Nicole Kivisto, testified that the primary reason for the rate increase request is increased investment in the facilities necessary to safely and reliably serve customers.[151] Ms. Kivisto explained that the gross investment in Minnesota gas distribution operations has increased by $19.7 million, or approximately 73 percent, from 2005 to the projected levels included in the test year.[152]

123. Great Plains' witness, Mr. Patrick Darras, testified that over the next several years, Great Plains plans significant investments in infrastructure necessary to comply with pipeline safety standards, other government regulations, and good utility practice. The upcoming investments include the replacement of all PVC pipe.[153] Mr. Darras explained that Great Plains has reallocated resources in recent years to increase spending on "its planned infrastructure replacement projects."[154]

124. The DOC-DER recommends a four-year recovery period for rate case expenses rather than the three year period proposed by Great Plains, which results in a decrease of the test year rate case amortization expenses of $43,750.[155]

125. It is difficult to estimate a recovery period because many factors impact a utility's need to file a rate case, including inflation, cost-of-money, construction activity, customers' usage, and accounting changes.[156] In addition, rate cases are time-

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[149] Ex. 215 at 9-11 (Lusti Direct); Ex. 216 at 2-5 (Lusti Surrebuttal).
[150] Ex. 19 at 15 (Jacobson Direct); Ex. 22 at 6–8 (Jacobson Rebuttal).
[151] Ex. 9 at 6 (Kivisto Direct).
[152] *Id.*
[153] Ex. 10 at 8-13 (Darras Direct).
[154] *Id.* at 7-8.
[155] Ex. 216 at 5 (Lusti Surrebuttal).
[156] Ex. 215 at 10 (Lusti Direct).

consuming and costly.[157] Generally, the DOC-DER recommends matching the amortization period with the average time period between rate cases.[158]

126. In rebuttal testimony, Great Plains' witness, Mr. Jacobson, testified that Docket No. G004/C-11-1110, a Commission investigation of Great Plains' earnings level, was a *de facto* rate case, which ought to be considered when determining the average period between Great Plains' rate cases.[159] The DOC-DER agreed to include this docket in its calculation.[160]

127. Therefore, the DOC-DER determined that Great Plains has essentially filed a rate case every 5.7 years, with an average period of time of 4.3 years between rate cases following Great Plains' merger with MDU, as demonstrated in the following table[161]:

Time Period between Rate Cases

Docket Number	Time Period Since Last Rate Case
G004/GR-75-433	
G004/GR-78-690	3 years
G004/GR-81-503	3 years
G004/GR-83-465	2 years
G004/GR-02-1682	19 years
G004/GR-04-1487	2 years
G004/CI-11-1110	7 years
G004/GR-15-879	4 years
Average	5.7 years
Average (since first rate case following the merger in Docket No. G004/PA-00-184)	4.3 years

128. The Administrative Law Judge concludes that the most relevant time period, especially given the 19 year anomaly, is the time period following the merger between Great Plains and MDU. Although the DOC-DER takes this position, it does not factor in the first rate case after the 2000 merger, Docket No. G004/GR-02-1682. If this

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157 *Id.*
158 *See* Ex. 215 at 10 (Lusti Direct).
159 Ex. 202 at 6-7 (Jacobson Rebuttal).
160 Ex. 216 at 2-3 (Lusti Surrebuttal).
161 DOC-DER Initial Post-Hearing Br. at 18-19.

rate case is considered, the average length of time between rate cases is 3.75, rather than 4.3, years.[162]

129. However, the Administrative Law Judge notes that although the 2011 case, G004/CI-11-1110, is considered a *de facto* rate case, a rate change resulted from the Commission ordering Great Plains to initiate a rate case due to alleged over-earning after a large customer was added to Great Plains' system.[163] The DOC-DER and Great Plains ultimately settled the matter.[164]

130. Because the average amount of time between rate cases is 5.7 years overall and 3.75 years post-merger, the Administrative Law Judge concludes that a four-year amortization period is appropriate. Therefore, the test year rate case amortization expenses should be decreased by $43,750.

131. Great Plains argues that if the amortization period is five years, the unamortized rate case expenses should be considered assets for rate base recovery.[165]

132. First, the DOC-DER no longer proposes, and the Administrative Law Judge does not recommend, a five-year amortization period.

133. In addition, the Administrative Law Judge is persuaded by the DOC-DER's contention that rate case costs are expenses rather than assets on which ratepayers would be charged a return.[166] Rate case expenses are not prepaid; instead, some costs occur before the test year, most occur during the test year, and some occur after the test year.[167] The DOC-DER testified that the Commission has not, to its knowledge, allowed rate base recovery of unamortized rate case expenses in recent years.[168]

D. Incentive Compensation

134. Great Plains bases its 2016 test year incentive compensation expenses on the average ratio of incentives to labor for 2012, 2013, and 2014.[169] In February 2016, the DOC-DER learned that Great Plains did not plan to pay its employees incentive compensation based on 2015 results.[170] Therefore, the DOC-DER suggested, and Great Plains agreed, that the three-year period should be adjusted to include 2015 and exclude 2012.[171]

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[162] (2+2+7+4)/4=3.75.
[163] Ex. 22 at 7 (Jacobson Rebuttal).
[164] *Id.*
[165] *Id.* at 7-8.
[166] Ex. 102 at 4 (Lusti Surrebuttal).
[167] *Id.*
[168] *Id.* at 4-5.
[169] Ex. 22 at 8 (Jacobson Rebuttal).
[170] Ex. 215 at 5 (Lusti Direct).
[171] Ex. 215 at 5 (Lusti Direct); Ex. 22 at 8 (Jacobson Rebuttal).

135. However, the DOC-DER and Great Plains have failed to reach an agreement regarding bonuses and commissions built into incentive compensation expenses.[172]

136. The DOC-DER recommends that Great Plains proposed incentive compensation amount be reduced by $89,032, for a total recoverable amount of $93,048.[173] The DOC-DER argues that this adjustment is appropriate because Great Plains "has not demonstrated why it would be reasonable to require ratepayers to pay for executive bonuses and commissions and depart from Commission precedent for calculating incentive compensation allowance."[174]

137. The Commission authorized a similar approach in Great Plains' 2004 rate case by reducing the requested incentive compensation expenses because they included "amounts that are for the benefit of shareholders and should not be recovered from ratepayers."[175]

138. Great Plains contends that the contested amount includes "more than MDU Resources executive bonuses. Specifically, Great Plains' health and wellness incentive has been included in that expense category along with all MDU Resources non-executive bonuses."[176] However, Great Plains has failed to demonstrate that its bonuses and commissions are "significantly based upon factors that are unrelated to earnings and stock price. Such incentive compensation is properly paid out of earnings, not by ratepayers."[177]

139. For these reasons, the Administrative Law Judge recommends reducing Great Plains test year incentive compensation by $89,032.

E. Compensation, Travel and Entertainment Expense

140. Great Plains included $38,502 in "travel, entertainment, and related employee expenses" for recovery as required by Minn. Stat. § 216B.16, subd. 17 (2014).[178] This itemization included "expenses for the ten highest paid officers and employees," totaling $4,170.[179]

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[172] *See* ISSUES MATRIX at 7 (Apr. 22, 2016).
[173] DOC-DER Initial Post-Hearing Br. at 21.
[174] *Id.* at 20-21.
[175] *In the Matter of a Petition by Great Plains Nat. Gas Co., a Division of MDU Resources Grp. Inc., for Authority to Increase Nat. Gas Rates in Minn.*, PUC Docket No. G-004/GR-04-1487, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 27 (May 1, 2006).
[176] Ex. 23 at 6 (Jacobson Testimony Summary).
[177] *See In the Matter of a Petition by Great Plains Nat. Gas Co., a Division of MDU Resources Grp. Inc., for Authority to Increase Nat. Gas Rates in Minn.*, PUC Docket No. G-004/GR-04-1487, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDED ORDER at 35 (Nov. 4, 2005).
[178] Ex. 19, TRJ-2 at 1 (Jacobson Direct).
[179] *Id.*

141. The DOC-DER does not take a position on the recoverability of these expenses.[180] The OAG recommended disallowance of $1,592 in expenses associated with two of the top ten compensated employees, K. Frank Morehouse and Richard Majors.[181]

142. According to the OAG, Great Plains should not recover Mr. Morehouse and Mr. Majors' expenses because they were incurred in 2014, yet Mr. Morehouse and Mr. Majors left Great Plains' employment prior to the 2016 test year.[182]

143. Although Great Plains no longer employs Mr. Morehouse and Mr. Majors, their positions have been filled: Ms. Kivisto replaced Mr. Morehouse and Mr. DiJulio replaced Mr. Majors.[183] A Great Plains' witness testified that "the two employees in question have left Great Plains but the positions have not been eliminated as each position has been filled. Therefore, while the individual performing the job function may have changed, the cost of performing that job function will likely remain very consistent."[184]

144. Nonetheless, the OAG argues that because Ms. Kivisto and Mr. DiJulio were also among the top ten compensated employees in 2014, "it would be inappropriate to recover compensation and employee expenses twice by including these two individuals as Top-10 employees in their previous positions and again as replacements to two other Top-10 employees who are no longer employed with Great Plains."[185]

145. Ms. Kivisto and Mr. DiJulio replaced Mr. Morehouse and Mr. Majors.[186] Likewise, the positions vacated by Ms. Kivisto and Mr. DiJulio were filled by other employees.[187] As noted by Great Plains, "[w]hile there has been a shift in the personnel that carry out the duties listed in Great Plains' top-10 list, each of the positions . . . continues to exist and expense[s] continue to be incurred in carrying out those duties."[188]

146. Because each of the top ten compensated positions has been filled, Ms. Kivisto and Mr. DiJulio have not been "double counted." Great Plains will have similar expenses during the test period regardless of the specific individual holding the position. Therefore, the Administrative Law Judge does not recommend the OAG's suggested disallowance.

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[180] DOC-DER Response to Issues Matrix at 12 (May 20, 2016).
[181] Ex. 100 at 14 (Lindell Direct).
[182] *Id.*
[183] *Id.* at 15.
[184] Ex. 23 at 4 (Jacobson Testimony Summary).
[185] Ex. 100 at 15 (Lindell Direct).
[186] *Id.*
[187] Ex. 22 at 12 (Jacobson Rebuttal).
[188] *Id.*

F. Medical/Dental Expenses

147. In 2014, Minnesota medical and dental benefits cost Great Plains $332,136.[189] In its Application filed in September 2015, Great Plains' predicted that medical and dental benefits would cost $371,132 in 2015 and $388,946 in 2016.[190]

148. On January 4, 2016, Great Plains filed supplemental data with actual expenses for the first ten months of 2015 and updated projections for the final two months.[191] The updated 2015 projection for medical and dental benefits was $337,482.[192] This resulted in a $33,650 difference between the original 2015 projection and the projected amount through ten months of 2015.

149. In Rebuttal Testimony filed March 21, 2016, Great Plains' witness, Mr. Jacobson, testified that the actual costs for medical and dental benefits in 2015 were $368,267.[193] Therefore, the actual cost for medical and dental benefits is only $2,865 less than the amount projected in Great Plains' Application.

150. Nonetheless, the OAG argues that because medical and dental benefits only increased 1.6 percent between 2014 ($332,136) and the 2015 updated amount ($337,482), a similar increase is reasonable for the 2016 test year.[194] The OAG therefore recommends a $46,064 disallowance of medical and dental expenses resulting in $342,882 rather than the requested $388,946.[195]

151. The OAG's assertion that $388,946 is an unreasonable increase is based on the updated 2015 prediction for Great Plains' medical and dental benefits. This predicted amount is $30,785 less than the actual cost of 2015 medical and dental benefits. The actual 2015 amount is only $2,865 less than the original predicted amount. It would not be fiscally sound to base the 2016 test year medical and dental costs on an updated prediction when actual cost data is available and significantly higher.

152. Moreover, Great Plains' medical and dental expenses increased by over 10 percent between 2014 and 2015. Yet, between the 2015 and the 2016 test years, Great Plains has only requested an approximate 5 percent increase. This request is reasonable.

153. In sum, because the requested $388,946 is reasonable in light of the substantial increase between 2014 and 2015, the Administrative Law Judge does not recommend the OAG's suggested $46,064 disallowance.

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[189] Ex. 21, TRJ-4 at 17 (Jacobson Direct Supplement).
[190] Ex. 2, C-2 at 10 (Application).
[191] Ex. 21, TRJ-4 at 17 (Jacobson Direct Supplement).
[192] *Id.*
[193] Ex. 22 at 11 (Jacobson Rebuttal).
[194] Ex. 100 at 9 (Lindell Direct).
[195] *Id.*

G. American Gas Association and Minnesota Chamber of Commerce Dues

154. Great Plains incurs expenses as a dues paying member of the American Gas Association (AGA) and the Minnesota Chamber of Commerce (Chamber).[196]

155. Relying on AGA's representation that 2.5 percent of AGA dues are related to lobbying, Great Plains excluded 2.5 percent of its AGA dues from the 2016 test year expenses, claiming a total of $9,072 for those dues.[197] Great Plains also identified 60 percent of Chamber dues as related to lobbying and removed a corresponding amount of those dues from the 2016 test year expenses, leaving a total of $522 for Chamber dues.[198]

156. The OAG recommends a 100 percent disallowance of both AGA and Chamber dues.[199] The OAG recommends these disallowances of the AGA and Chamber dues because it argues that the AGA and the Chamber are primarily lobbying organizations whose activities do not benefit ratepayers.[200]

157. The OAG points out that the AGA states its mission is advocating for natural gas issues for its members, and that the AGA states that it serves as a voice on behalf of the energy utility industry and promotes natural gas demand growth.[201]

158. The OAG argues that a substantial portion of the AGA's activities are directed at lobbying on behalf of local distribution companies like Great Plains.[202] The OAG also notes that the fact that the AGA is headquartered in Washington, D.C. and its president is a former congressman supports the OAG's position that the AGA is primarily a lobbying organization.[203]

159. Great Plains opposes disallowance of its proposed reimbursement amount of AGA dues. Great Plains agrees that the AGA engages in advocacy for natural gas issues.[204]

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[196] Ex. 22 at 12-13 (Jacobson Rebuttal); Ex. 100 at 16 (Lindell Direct).
[197] Ex. 22 at 12-13 (Jacobson Rebuttal); Ex. 100 at 16 (Lindell Direct).
[198] Ex. 22 at 12-13 (Jacobson Rebuttal).
[199] Ex. 100 at 16-17 (Lindell Direct).
[200] Ex. 100 at 16 (Lindell Direct); Ex. 102 at 5 (Lindell Surrebuttal).
[201] Ex. 100 at 16-17 (Lindell Direct).
[202] Ex. 100 at 16-17 (Lindell Direct).
[203] *Id.*
[204] Ex. 22 at 12-13 (Jacobson Rebuttal).

160. Great Plains states that the AGA addresses a variety of issues including "important topics such as safety, security and emergency planning as well as issues dealing with the environment."[205] According to Great Plains AGA:

- Focuses on the advocacy of natural gas issues that are priorities for the membership and that are achievable in a cost-effective way;

- Encourages, facilitates and assists members in sharing information designed to achieve operational excellence by improving their safety, security, reliability, efficiency, environmental and other performance metrics;

- Assists members in managing and responding to customer energy needs, regulatory trends, natural gas markets, capital markets and emerging technologies;

- Collects, analyzes and disseminates information on a timely basis to policy makers and the public about energy utilities and the natural gas industry;

- Serves as a voice on behalf of the energy utility industry and promotes natural gas demand growth by emphasizing before a variety of audiences the energy efficiency, environmental and other benefits of natural gas and promotes natural gas supply growth by advocating public policies favorable to increased supplies and lower prices to customers; and

- Delivers measurable value to AGA members.[206]

161. The OAG observes that Great Plains paid dues to a number of local chambers of commerce, which the OAG acknowledges appear to be reasonable. However, the OAG argues that full disallowance of the $522 in Chamber dues is appropriate because the Chamber is a lobbying organization that provides "limited or no direct benefits to the communities that Great Plains serves."[207]

162. Great Plains did not respond directly to the OAG's contentions regarding the Chamber dues. Great Plains stated in its Issues Matrix that it does not oppose the OAG's 100 percent disallowance of Chamber dues[208] but that is not reflected in the evidentiary record, or stated in Great Plains' post-hearing briefs.

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205 Ex. 22 at 12 (Jacobson Rebuttal).
206 Ex. 19, TRJ-1 at 1 (Jacobson Direct).
207 Ex. 100 at 16 (Lindell Direct).
208 ISSUES MATRIX at 11 (Apr. 22, 2016).

163. The Commission may not allow recovery of expenses such as membership dues or lobbying expenses when it deems those expenses to be "unreasonable and unnecessary for the provision of utility service."[209]

164. In similar cases, the Commission has determined that when it is not possible to determine what portion of AGA dues are used for lobbying, or to analyze the extent to which the AGA's lobbying might have served ratepayer interests, "that the most appropriate response is to disallow recovery of the entire amount."[210]

165. The Administrative Law Judge concludes that Great Plains' adoption of the AGA's bare representation that only 2.5 percent of dues are attributable to lobbying is not credible, without more, in light of the evidence concerning the AGA's activities, location and leadership. The Administrative Law Judge further concludes that Great Plains provided no argument or evidence to counter the OAG's objections to including the Chamber dues in test year costs.

166. The Administrative Law Judge concludes that Great Plains failed to demonstrate by a preponderance of the evidence that either its AGA dues or its Chamber dues are reasonable and necessary for the provision of utility services and appropriate for inclusion in recoverable test year costs.

IX. TEST YEAR RATE BASE

167. The DOC-DER and Great Plains agree on Great Plains' proposed rate base.[211] However, the issue is disputed between the OAG and Great Plains.[212]

168. Great Plains proposed a rate base amount in this proceeding of $16,836,799 based on its 2016 test year.[213]

169. Great Plains used a forecasted test year representing the 12 months ending December 31, 2016.[214] Development of the 2016 test year began with 2014 actual results and then included many adjustments in the determination of the 2015 and 2016 projected years.[215]

170. In updated information filed on January 4, 2016, Great Plains provided rate base projections showing a reduction in their previous projection by $212,888 or 1.6 percent.[216]

[209] Minn. Stat. § 216B.16, subd. 17(a).
[210] *Id.* at 28.
[211] Ex. 215 at 8 (Lusti Direct).
[212] *Id.*
[213] Ex. 2, Statement A at 1 (Application).
[214] Ex. 200 at 4 (Johnson Direct).
[215] Ex. 215 at 3 (Lusti Direct).
[216] Ex. 21 at 2 (Jacobson Direct Supplement).

171. The primary difference between the rate base projection in the initial application and the supplemental filing is a lower projection for plant in-service cost of $187,944. Great Plains discovered two projects related to vehicles and work equipment that had amounts incorrectly assigned to Minnesota.[217]

172. The OAG argues that because Great Plains' updated rate base figures for 2015 are $212,888 lower than initially projected, the rate base should be adjusted downward by the same amount.[218]

173. Great Plains counters that because the updated information was based on the actual average rate base from January to October 2015 and estimates from November and December 2015, the updated information should only be used as a check on the reasonableness of the projected 2015 information.[219] Great Plains believes its proposed 2016 test year rate base projections are reasonable given that projected capital additions for 2016 are $4.3 million.[220]

174. Great Plains' investment in Minnesota gas operations has increased by $19.7 million, or approximately 73 percent, from 2005 to the 2016 projected levels included in this case.[221]

175. The increase is driven by investments in the facilities needed to safely and reliably serve customers, including investments in an automated meter reading system, a new customer care and billing system, a new mobile dispatch system, and a compliance monitoring program.[222]

176. Great Plains argues that the OAG's recommended adjustment is unnecessary in light of its recent and likely future level of investment, of which a slight unexpected capital addition could result in a change in the OAG's recommended adjustment.[223]

177. The Administrative Law Judge agrees with the OAG that because the update provided a check on the reasonableness of Great Plains' initial figures and revealed capital expenses inappropriately assigned to Minnesota from which Minnesota ratepayers would receive no benefit, the OAG's proposed reduction of $187,944 should be adopted by the Commission.

[217] *Id.*
[218] Ex. 100 at 11 (Lindell Direct).
[219] *Id.* at 9-11.
[220] Ex. 22 at 11 (Jacobson Rebuttal).
[221] Ex. 9 at 6 (Kivisto Direct).
[222] Ex. 9 at 6 (Kivisto Direct); Ex. 200 at 5-6 (Johnson Direct).
[223] Ex. 22 at 11 (Jacobson Rebuttal).

X. RETURN ON EQUITY (ROE)

A. Introduction

178. In a competitive environment, the forces of supply and demand interact to determine prices and incomes in such a way that resources are allocated to produce an optimal mix of goods and services. In the case of public utilities, the conditions necessary for competition to yield an efficient outcome are not met; regulatory agencies must therefore ensure that public utilities provide an appropriate supply of satisfactory services at reasonable rates. [224]

179. In order to properly serve the public, the utility must be able to compete successfully for necessary funds in the capital markets. To attract these funds, the utility must earn enough to offer competitive returns to investors. Thus, a fair return is one that enables the utility to attract sufficient capital at reasonable terms.[225]

180. Minnesota Statutes section 216B.03 (2014) requires that "[a]ny doubt as to reasonableness should be resolved in favor of the consumer."

181. A fair rate of return, as required by the statute, is the rate that, when multiplied by the rate base, will give the utility a reasonable return on its total investment.[226]

182. The components of a fair rate of return include a determination of capital structure, cost of debt, and a reasonable return on common equity.[227]

183. The cost of equity capital to a utility is the rate of return that it may pay to equity investors to induce them to invest in its regulated operations.[228]

184. In this case, the cost of equity issue is disputed by Great Plains, the DOC-DER, and the OAG. Great Plains recommended a ROE of 10.0 percent.[229] The DOC-DER originally recommended a cost of equity, or ROE of 9.77 percent.[230] In Surrebuttal Testimony, the DOC-DER updated its ROE recommendation to 9.18 percent.[231] The

[224] Ex. 204 at 2-3 (Addonizio Direct).
[225] *Id.*
[226] *Id.*
[227] Minn. Stat. § 216B.16, subd. 6 (2014) ("In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, the commission shall give due consideration to evidence of the cost of the property when first devoted to public use, to prudent acquisition cost to the public utility less appropriate depreciation on each, to construction work in progress, to offsets in the nature of capital provided by sources other than the investors, and to other expenses of a capital nature.").
[228] Ex. 204 at 4 (Addonizio Direct).
[229] Ex. 14 at 40 (Gaske Direct).
[230] Ex. 204 at 59 (Addonizio Direct).
[231] Ex. 205 at 1-2 (Addonizio Surrebuttal).

OAG did not take a position on the final ROE, but did object to the inclusion of a flotation cost adjustment in the ROE, as explained more fully below.[232]

B. Market/Risk Analyses Used by the Parties

1. Principles of Rate Case Equity Cost Analysis

185. Because Great Plains is a division of MDU, it does not have publicly traded common stock upon which a direct, market-based analysis of the propriety of its cost of common equity could be based.[233] A more indirect method of analysis must be applied.

186. A purchaser of a company's common stock (equity) is investing in the hope of receiving a stream of dividends in the future.[234] In order for potential investors to be induced to purchase a company's stock, the company's expected future dividends must promise a rate of return that is at least equal to the best alternative investment with a similar level of risk.[235] Since it is a well-accepted financial principle that companies with similar investment risks are expected to have similar costs of equity, a company such as Great Plains must pay an equity return similar to the equity return that investors expect to earn on investments of comparable risk.[236] This rate of return is the cost of equity for Great Plains.[237]

187. In order to arrive at their recommended cost of equity in this rate case, Great Plains and the DOC-DER first devised proxy groups of publicly traded companies that the parties considered to have investment risks similar to those of Great Plains.[238]

2. The Parties' Proxy Companies

188. In composing its group of proxy companies, Great Plains started with the eleven companies that the Value Line Investment Survey (Value Line) classifies as Natural Gas Utilities to ensure that Great Plains is considered to be primarily engaged in the natural gas distribution business and that retention growth rate projections are available. From that group, Great Plains eliminated any companies that did not have investment-grade credit ratings from either Standard & Poor's (S&P) or Moody's Investors Service (Moody's) because such companies are not sufficiently comparable in terms of business and financial risk to Great Plains.[239]

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[232] Ex. 100 at 26-28 (Lindell Direct).
[233] Ex. 14 at 18 (Gaske Direct).
[234] Ex. 204 at 4 (Addonizio Direct).
[235] *Id.*
[236] *Id.* at 4, 9.
[237] *Id.* at 4.
[238] Ex. 204 at 9-15 (Addonizio Direct); Ex. 14 at 18-19 (Gaske Direct).
[239] Ex. 14 at 19 (Gaske Direct).

189. In addition, Great Plains excluded from the original 11 companies any that did not pay dividends, or that did not have future growth rate estimates provided by either Zacks or Thomson First Call.[240]

190. In order to ensure that the proxy companies are primarily engaged in the natural gas distribution business, Great Plains eliminated any that did not derive at least 60 percent of their operating income from regulated natural gas distribution operations in 2014, or that did not have at least 60 percent of their total assets devoted to the provision of natural gas distribution service in 2014.[241]

191. The following eight companies satisfied Great Plains' screening criteria and were included in Great Plains' proxy group: Atmos Energy Corp. (ATO); Laclede Group, Inc. (SR); Northwest Natural Gas Great Plains (NWN); South Jersey Industries, Inc. (SJI); Southwest Gas Corporation (SWX); WGL Holdings, Inc. (WGL); Piedmont Natural Gas Great Plains (PNY); and New Jersey Resources Corporation (NJR). [242]

192. The DOC-DER chose a group of companies that the agency considered pose business risks to investors similar to those experienced by Great Plains investors.[243] To create the group, the DOC-DER first began a search in the Research Insight Database for companies that: are natural gas distribution companies; are traded on one of the stock exchanges; and have credit rating from S&P.[244] This screen produced a group of eleven potential proxy companies.[245]

193. The DOC-DER next added to the list companies that are classified by Value Line, a respected investor service, as natural gas utilities and are traded on one of the stock exchanges. This process increased the proxy list to a possible 16 comparable companies.[246]

194. According to the DOC-DER, companies that have credit ratings similar to Great Plains may have comparable risk profiles and are therefore suitable for inclusion in a ROE proxy group, while companies with credit ratings that are significantly higher or lower than Great Plains' may have different risk profiles that render them unsuitable for inclusion.[247] From companies that met both of the first two sets of screens, the DOC-DER eliminated companies that had an S&P credit rating outside the range of BBB- to A+.[248]

195. The DOC-DER also eliminated companies that are known to be involved in merger or acquisition activity. Merger and acquisition activity can have significant

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240 *Id.*
241 *Id.*
242 *Id.,* JSG-3 at 2.
243 Ex. 204 at 9 (Addonizio Direct).
244 *Id.* at 9-10.
245 *Id.* at 11.
246 Ex. 204 at 11-12 (Addonizio Direct).
247 *Id.* at 12.
248 *Id.*

impacts on a share price that renders it unsuitable for use in a Discount Cash Flow (DCF) analysis.[249]

196. In the end, the DOC-DER's proxy group consisted of six of the eight companies that made up Great Plains' list.[250] The DOC-DER did not include two of Great Plains' proxy companies because the DOC-DER considered them less risk comparable.[251] The DOC-DER excluded (PNY) in its proxy group because Great Plains announced in October, 2015, that it was being acquired by Duke Energy.[252] The merger announcement came after Great Plains filed its testimony creating its proxy list and related cost of equity analysis.[253]

197. The DOC-DER also excluded (NJR) from the eight proxy companies chosen by Great Plains. NJR filed its 2015 SEC Form 10-K, with financial statements for its fiscal year 2015, after Great Plains' expert filed his Direct Testimony. NJR's SEC filing indicates that, in 2015, NJR earned less than 60 percent of its operating income from natural gas distribution services, and thus did not meet the DOC-DER's criteria for inclusion in the DOC Proxy Group.[254] In 2015, 70 percent of NJR's assets were devoted to natural gas distribution services, and therefore the DOC-DER believed NJR would still meet Great Plains' asset criteria, despite earning less than 60 percent of its operating income from natural gas distribution. The DOC-DER concluded that what matters to investors is Great Plains' ability to pay dividends, which is a function of its income, not its assets.[255] In the case of NJR, in 2015 more than 40 percent of its operating income was derived from operations other than the provision of natural gas distribution service, which means that much of NJR's ability to pay dividends was based on lines of business other than natural gas distribution. In the DOC-DER's opinion, NJR was unsuitable for a proxy group based on risk dissimilarity.[256]

198. The DOC-DER's final proxy group consisted of the following companies: Atmos Energy Corporation; Laclede Group, Inc.; Northwest Natural Gas Great Plains; South Jersey Industries, Inc.; Southwest Gas; and WGL Holdings, Inc.[257]

199. In his Surrebuttal Testimony, the DOC-DER's expert, Mr. Addonizio, re-ran his selection process for his proxy group, which did not result in any modifications.[258]

200. The Administrative Law Judge finds that both Great Plains and the DOC-DER applied appropriate screens to determine their proxy companies.

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[249] *Id.*
[250] *Id.* at 15.
[251] *Id.* at 41-42.
[252] *Id.*
[253] *Id.*
[254] *Id.* at 42.
[255] *Id.*
[256] Ex. 204 at 42-43 (Addonizio Direct).
[257] *Id.* at 15.
[258] Ex. 205 at 2 (Addonizio Surrebuttal).

3. Cost of Equity Methodologies Used by the Parties

a. Discounted Cash Flow (DCF) Analysis

201. The DCF analysis for determining cost of equity reflects the assumption that the market price of a share of common stock represents the discounted present value of the stream of all future dividends that investors expect the firm to pay. [259] This premise is shown as follows:

> The current price of a stock = the present value of all expected future dividends, discounted by the appropriate rate of return.[260]

202. The DCF method suggests that investors in common stocks expect to realize returns from two sources: a current dividend yield plus expected growth in the value of their shares as a result of future dividend increases. [261]

203. The DCF model, assuming constant growth of dividends over time, is reflected in the following formula:

> The cost of equity = the expected dividend yield + the expected growth rate in dividends.[262]

204. Estimating the cost of capital with the DCF method is a matter of calculating the current dividend yield and estimating the long-term future growth rate in dividends that investors reasonably expect from a stock.[263]

205. The dividend yield portion of the DCF method uses readily-available information regarding stock prices and dividends. The market price of a firm's stock reflects investors' assessments of risks and potential earnings as well as their assessments of alternative opportunities in the competitive financial markets. By using the market price to calculate the dividend yield, the DCF method implicitly recognizes investors' market assessments and alternatives.[264]

206. The other component of the DCF formula is investors' expectations regarding the future long-run growth rate of dividends. This component is not readily apparent from stock market data and must be estimated using informed judgment.[265] Great Plains and the DOC-DER applied mathematical formulas based on, among other

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[259] Ex. 14 at 15 (Gaske Direct).
[260] Ex. 204 at 5 (Addonizio Direct).
[261] Ex. 14 at 15 (Gaske Direct).
[262] Ex. 204 at 6 (Addonizio Direct).
[263] Ex. 14 at 15 (Gaske Direct).
[264] *Id.*
[265] *Id.*

factors, the timing of future dividend payments to arrive at their projected long-run growth rates.[266]

207. The Commission "has historically placed its heaviest reliance" on the DCF analysis for determining an appropriate cost of equity.[267]

b. Two-Growth DCF (TGDCF) Model

208. A subset of the DCF methodology is the "two-growth" DCF or TGDCF model. This method assumes that dividends do not grow at a constant rate but at one rate for five years, and at a second, sustainable rate for year six and beyond.[268] The choice of a five-year period stems from the fact that industry growth projections such as Zacks, Value Line, and Thomson are all five-year models. The DOC-DER applied these models for the first growth period under this analysis, but chose alternative growth rates for those results it did not consider sustainable in the long run.[269]

c. Capital Asset Pricing (CAPM) Model

209. The basic premise of the CAPM model is the assumption that any stock-specific risk can be diversified away by investors. Therefore, the only risk that is relevant is the systematic risk of the stock, which is measured by beta.[270] The formula for CAPM, in its simplest form, assumes the following:

$$k = r_f + \text{beta} \times (r_m - r_f)$$

Where k is the required rate of return on the stock in question; r_f is the rate of return on a riskless asset,; and r_m is the required rate of return on the market portfolio.[271]

210. While the CAPM methodology is theoretically sound, its use as a method to estimate Great Plains' cost of equity raises concerns regarding the difficulty determining the appropriate: 1) beta; 2) riskless asset; and 3) estimate of the required return on the market portfolio.[272]

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[266] Ex. 14 at 16 (Gaske Direct); Ex. 204 at 5-7 (Addonizio Direct).
[267] *In the Matter of the Application of N. States Power Great Plains for Auth. to Increase Rates for Elec. Serv. in Minn.,* PUC Docket No. E-002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 53 (May 8, 2015).
[268] Ex. 204 at 21-24 (Addonizio Direct).
[269] *Id.*
[270] *Id.* at 27.
[271] Ex. 204 at 27 (Addonizio Direct).
[272] *Id.*

211. Great Plains used the CAPM model as a check of reasonableness of its DCF analyses.[273] The DOC-DER also applied the CAPM analysis as a benchmark for the reasonableness of its DCF analyses.[274]

d. Flotation Cost Adjustment

212. Flotation costs are Great Plains' costs of issuing new shares of common stock. Due to the application of issuance costs, the price paid by an investor for a new share is higher than the price received by Great Plains upon issuing the new share.[275]

213. The premise of an upward adjustment to Great Plains' cost of equity to account for flotation cost is that adjustment allows Great Plains to earn a higher percentage return on its stock issuance proceeds (equity) in order to align with investors' required rate of return on the purchase of the issued stock.[276]

214. Both the DCF and CAPM models of determining cost of equity measure the required return on the overall value of shareholders' equity holdings; they do not factor in a return on the Great Plains net proceeds after it pays the costs of stock issuance. A flotation adjustment, if applied, would be an addition to the results of the DCF or CAPM analysis. [277]

C. Positions of the Parties

1. Great Plains

215. Through the testimony of Dr. J. Stephen Gaske, Great Plains stated that a ROE of 10.0 percent adequately reflects the unique risks faced by Great Plains and would result in a return sufficient to attract new capital on reasonable terms.[278]

216. In determining its proposed ROE, Great Plains calculated the cost of common equity capital for Great Plains' Minnesota natural gas distribution operations based on three DCF analyses of the group of the eight proxy companies it had developed. The three models each used a different growth rate estimation method: 1) retention growth (also known as "sustainable growth") forecasts from Value Line forecasts of dividends, earnings, and returns on equity; 2) a Basic DCF analysis that relied on analysts' earnings forecasts for the growth rate component of the model; 3) a combination of the Value Line retention growth forecasts and analysts' earnings growth projections to produce a Blended Growth Rate Analysis.[279]

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[273] Ex. 14 at 29-30 (Gaske Direct).
[274] Ex. 204 at 26 (Addonizio Direct).
[275] *Id.* at 24.
[276] *Id.* at 24-25.
[277] *Id.* at 25.
[278] Ex. 14 at 40 (Gaske Direct).
[279] *Id.* at 20.

217. For each member of its proxy group, Great Plains calculated monthly estimates of dividend yield for the 6 month period from February of 2015 through July of 2015. Great Plains then averaged the monthly dividend yield estimates to produce the final dividend yield in its DCF analyses. The analysis used each proxy's quarterly dividend level during the month, annualized. To estimate each proxy's stock price for each month, Great Plains used the average of Great Plains' highest and lowest stock prices observed during the month. Finally, Great Plains adjusted dividend yields to account for expected growth during the next year. [280]

218. In response to the DOC-DER's initial recommendation on ROE, Great Plains stated that, while it believed its method of calculating the dividend yield was reasonable, as a practical matter the results of the DOC-DER's and Great Plains' varying analyses were not materially different.[281]

219. In addition to its three DCF analyses, Great Plains conducted a risk premium analysis, a market DCF analysis of the S&P 500, and a CAPM analysis as benchmarks to assess the reasonableness of the DCF results.[282]

220. Great Plains' DCF results are summarized in Table 1 below:

Table 1: Summary of DCF Results[283]

	Retention Growth DCF Analysis	Basic DCF Analysis	Blended Growth Rate DCF Analysis
High	10.79%	10.42%	10.56%
3rd Quartile	8.84%	10.12%	9.33%
Median	8.47%	9.23%	8.75%
1st Quartile	8.06%	8.57%	8.26%
Low	7.04%	7.64%	8.02%

221. Great Plains contended that flotation costs must also be considered in determining the cost of capital because they are significant costs associated with issuing new common equity capital. [284] Great Plains included a representative sample of flotation costs incurred with 50 new common stock issues by natural gas distribution companies since January 2000. Flotation costs associated with these new issues averaged 3.90 percent.[285]

222. Great Plains concluded that in order to be able to issue new common stock on reasonable terms, without diluting the value of the existing stockholders' investment, Great Plains must have a flotation adjustment of approximately 4.0 percent

[280] Ex. 204 at 43-44 (Addonizio Direct).
[281] Ex. 15 at 6 (Gaske Rebuttal).
[282] Ex. 14 at 27-30 (Gaske Direct).
[283] Ex. 16 at 1 (Gaske Testimony Summary).
[284] Ex. 14 at 17 (Gaske Direct).
[285] *Id.*

above book value to its cost of equity. The cost of common equity capital would therefore be the investor return requirement multiplied by 1.04. [286]

223. Great Plains compared the addition of a flotation cost adjustment, regardless of whether a Great Plains can confidently predict a need to issue new common stock in advance, to the idea of maintaining a sound credit rating whether or not Great Plains expects to be borrowing money in the near future.[287]

224. Great Plains did not quantify the cost of equity before accounting for flotation costs, but rather embedded the additional multiplier of 1.04 within its proposed cost of equity.[288]

225. Great Plains concluded that its DCF analyses "establish a range for an appropriate rate of return for a gas distribution stock" and that it "normally do[es] additional analysis to determine the risk of the target stock relative to the proxy companies in order to determine where the target stock falls within the range."[289]

226. Great Plains undertook an analysis of Great Plains' risk level relative to the risk level of the other companies included in Great Plains' proxy group, focusing on four broad categories of risk: business risk, regulatory risk, financial risk, and market risk. [290]

227. Great Plains stated that it is adversely affected by certain business risks including its small size, its small revenue base, an undiversified local economy that is heavily dependent on agriculture, competition from alternative fuel sources and declining use per customer due in part to its aggressive energy conservation efforts.[291] Great Plains' Minnesota natural gas distribution operation projected 2016 operating revenues and operating income are only 1.32 percent and 0.18 percent of the year-end 2014 level for its median proxy group, respectively.[292] Although Great Plains stated that it has average financial, market and regulatory risks, it concluded that the aforementioned business risk factors result in its having above-average business risk relative to its proxy group.[293]

228. Based upon its analyses and the aforementioned business risk factors, Great Plains recommended that its ROE, including flotation costs, should properly be set at 10 percent, a number that is slightly below the third quartile for its basic DCF

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[286] *Id.*
[287] *Id.* at 17-18.
[288] Ex. 100 at 26 (Lindell Direct).
[289] Ex. 16 at 1 (Gaske Testimony Summary).
[290] Ex. 14 at 30-38 (Gaske Direct).
[291] *Id.* at 31-33, 37-38.
[292] *Id.* at 31-32.
[293] *Id.* at 37-38

analysis and between the third quartile and the high range of its supporting DCF analyses.[294]

229. Great Plains was critical of the DOC-DER's downward adjustment in surrebuttal testimony from a recommended 9.77 percent ROE to 9.18 percent. Great Plains stated that the DOC-DER's update depended on market fluctuations and growth revisions during the past month.[295] Because rates established in this rate case will be in effect for a year or more, Great Plains opined that it is more reasonable to use its 6 month input average to develop ROE.[296] Great Plains further noted that its recommended ROE of 10 percent lay within the zone of reasonableness of 8.17 and 10.27 percent established by the DOC-DER in its final ROE recommendation.[297]

230. Great Plains did not update its rate of return analysis after its original filing.[298]

2. The DOC-DER

231. To estimate the cost of equity capital, the DOC-DER analyst Mr. Craig M. Addonizio used a market-oriented approach and relied on the concept of "opportunity costs."[299] The DOC-DER stated that, in order to attract equity investors, Great Plains' expected future dividends must provide the investors with a rate of return that is at least equal to the best alternative investment available with a similar risk.[300]

232. For the expected dividend yield, the DOC-DER determined the expected dividend yield for each stock in the DOC-DER's proxy group using its current stock price and its most recent dividend, which are directly observable.[301]

233. The DOC-DER used a DCF analysis and a TGDCF analysis, adjusted for 3.74 percent flotation costs, to arrive at an initial recommended ROE of 9.77 percent on Great Plains' common equity capital. This figure was the mean of its proposed range of 8.64 percent to 11.05 percent.[302]

234. The DOC-DER contended that recent share prices must be used for analysis of cost of equity because the current price per share incorporates all relevant publicly available information.[303] Share prices can be volatile in the short run.[304] For these reasons, it is desirable to use an average share price of a period of time long

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[294] *Id.* at 40.
[295] Ex. 16 at 2 (Gaske Testimony Summary).
[296] *Id.*
[297] *Id.*
[298] Ex. 205 at 7 (Addonizio Surrebuttal).
[299] *Id.* at 4.
[300] Ex. 205 at 4 (Addonizio Surrebuttal).
[301] Ex. 204 at 16 (Addonizio Direct).
[302] *Id.* at 26.
[303] *Id.* at 19.
[304] *Id.*

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.[305] The DOC-DER initially calculated the share price as the average of the closing price over the 30 trading days ending one month prior to the filing date of its analysis, February 3, 2016.[306]

235. The DOC-DER reasoned that a flotation cost adjustment is necessary to allow Great Plains to generate enough proceeds from its stock issuance, net of the issuance costs, to achieve the rate of return on the stock cost that investors demand.[307]

236. The DOC-DER contended that to find the appropriate flotation cost the dividend yields of the companies in the DOC-DER's comparison group must be adjusted by dividing them by 1-F, where F is the percentage of flotation costs. Great Plains provided data regarding equity issuances by natural gas distribution companies over the period 2000-2015, and the flotation costs incurred by those companies. Using this data, the DOC-DER calculated that the average percentage of flotation costs, F, is 3.74 percent.[308]

237. In Surrebuttal Testimony, the DOC-DER updated its DCF analysis by using the most recently available dividend yields and expected growth rates for companies in its proxy group (30 trading days ending March 28, 2016), and revised its recommended 9.77 percent to 9.18 percent, the mean of its new range of 8.15 percent to 10.27 percent.[309] The updated ROE recommendation was thus 9.18 percent with flotation costs, with an overall cost of capital of 7.09 percent. [310]

238. The DOC-DER based its change to ROE on the fact that stock prices in its proxy group had changed, some of the companies had increased their dividends, and the investor services had updated some of their earnings growth estimates.[311]

239. Below is a summary of the DOC-DER's final DCF results: [312]

Summary of DCF Results Adjusted for Flotation Costs

Model	Low ROE	Mean ROE	High ROE
Constant Growth DCF	8.17%	9.12%	10.27%
TG DCF	8.15%	9.18%	10.25%

305 *Id.*
306 *Id* at 24-25.
307 *Id.* at 25.
308 *Id.* at 25-26.
309 Ex. 205 at 1-4 (Addonizio Surrebuttal).
310 *Id.*
311 *Id.*
312 *Id.* at 4.

240. The DOC-DER contended that Great Plains' recommended 10 percent ROE was unreasonable for a number of reasons, including the use of data the DOC-DER considered outdated and the Company's relative risk analysis. [313]

241. Basic financial principles hold that financial markets are efficient, with current stock prices fully reflecting all publicly available information.[314] The DOC-DER reasoned that Great Plains should avoid using long-term historical prices.[315] The DOC-DER contended that by averaging monthly dividend yields for its proxy companies over a 6-month period, Great Plains inappropriately gave equal analytical weight to stock prices from the prior six months as it did to stock prices from the most recent month.[316] The Great Plains ROE witness conceded that the most recent data he used in his DCF analysis was at least eight months old and in some cases over a year old. [317]

242. The DOC-DER disagreed with Great Plains' use of risk analysis to justify an allowed cost of equity at the high end of the range established for its proxy group in its DCF analyses.[318] The DOC-DER noted that Great Plains' recommended ROE of 10 percent is more than 75 basis points above the median results of any of its DCF analyses, indicating that the risk analysis had a significant impact on Great Plains' recommended cost of equity.[319]

243. The DOC-DER further noted that Great Plains found its risk comparable to other members of its proxy group in the three categories of regulatory, financial and market risk. Only in the category of business risk did Great Plains claim to experience greater than average risk, and in that case Great Plains offered no hint as to the magnitude of the adjustment. [320] Finally, the DOC-DER contended that relative risk had been a major selection criterion for Great Plains' proxy company list. Risk had been considered fully in that screening and should not be considered again as a factor supporting a higher than median level of cost of common equity.[321]

3. The OAG

244. The OAG's witness, Mr. John Lindell, addressed the reasonableness of including a flotation cost adjustment to ROE.

245. As noted above, both Great Plains and the DOC-DER recommended an adjustment to cost of equity to reflect flotation costs. Great Plains recommended a

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[313] Ex. 204 at 44 (Addonizio Direct); Ex. 205 at 7-9 (Addonizio Surrebuttal).
[314] Ex. 204 at 44 (Addonizio Direct).
[315] *Id.*
[316] *Id.* at 44-45.
[317] Evidentiary Hearing Tr. at 21-22 (Gaske).
[318] Ex. 204 at 56-58 (Addonizio Direct).
[319] *Id.* at 57.
[320] Ex. 204 at 57 (Addonizio Direct); Ex. 14 at 37-38 (Gaske Direct).
[321] Ex. 204 at 57-58 (Addonizio Direct).

flotation cost multiplier of 1.04.[322] The DOC-DER applied a flotation cost adjustment of 3.74 percent.[323]

246. Great Plains' parent, MDU, last issued stock in 2004.[324]

247. The OAG contended that the application of a flotation cost adjustment is inappropriate in this case for a number of reasons:

1) Investors' expectations for utility stocks are not based on net proceeds from a stock issuance. The market and investors are sophisticated and are aware that the net proceeds of stock issuances are less than what they invested—in other words, investors have already factored in the flotation costs in making their investment decisions.

2) There is no evidence that Great Plains intends to issue stock at any time in the near future. Proceeding with a flotation cost adjustment would unreasonably reward utility shareholders for costs the utility will not incur.

3) In seeking an adjustment for flotation costs only, Great Plains ignored other transaction costs, such as investors' brokerage fees, which could warrant a downward adjustment in ROE.

4) As a subsidiary of MDU, Great Plains does not issue its own stock and makes up less than one percent of its parent's resources.[325]

4. Conclusions and Recommendation

248. Great Plains and the DOC-DER applied multiple similar screens to arrive at the risk-comparable proxy companies upon which they built their analyses. The companies were in fact the same, with the exception of two that the DOC-DER eliminated from Great Plains' group, PNY and NJR. There is no showing that the inclusion or elimination of these two companies rendered either proxy group more appropriate.

249. In the recent CenterPoint rate case, the Commission reaffirmed its longstanding confidence in the DCF model for determining cost of equity (and cited the CAPM as an appropriate corroborating tool).[326] In this case Great Plains and the DOC-DER both applied DCF methodologies to determine their recommended cost of equity, Great Plains with three DCF subtypes, the DOC-DER with two. These parties also

[322] Ex. 14 at 17 (Gaske Direct).
[323] Ex. 204 at 25-26 (Addonizio Direct).
[324] Ex. 100 at 27 (Lindell Direct).
[325] Ex. 100 at 27-28 (Lindell Direct).
[326] CENTERPOINT PUC ORDER at 38.

developed CAPM models as benchmarks of reasonableness for their analyses and Great Plains further conducted a risk premium analysis. The parties' models were broad and thorough.

250. A significant difference in the parties' final recommendations stemmed from the DOC-DER's calculation of share price as the average of the closing price over the preceding 30 trading days. When the stock prices and dividends in its proxy group changed and investor services updated some of their data—adjustments that are of note but not anomalous in the market—the DOC-DER updated its analysis to reflect the most recent 30-day trading period before the filing of testimony closed. Great Plains' analysis stayed static as it continued to depend on its original filing based on data gathered from the six-month period from February of 2015 through July of 2015. In the CenterPoint rate case, the Commission found that the DOC-DER's use of a 30-day trading period in its DCF analyses, in the absence of volatility or anomalies during the period, best captured all publicly available information and investor expectations of Great Plains.[327] The Administrative Law Judge concludes that this finding applies equally in this case.

251. The DOC-DER and Great Plains also diverged in their consideration of risk factors in their analyses of cost of equity. To form its recommendation on cost of equity, the DOC-DER chose the mean of the range of results from its DCF analysis. Based on what it considered unique risk factors, however, Great Plains recommended that its ROE should properly be set at 10 percent, a number that is slightly below the third quartile for its basic DCF analysis and between the third quartile and the high of its supporting DCF analyses.[328] While the choice of a mean result is not sacrosanct, the Administrative Law Judge does not find that Great Plains has supported its upward adjustment from its mean DCF results for risk. Great Plains carefully formed its proxy group based upon comparable risk factors; Great Plains has not demonstrated that the business risks it now cites as the reason for its final ROE recommendation are unique or should be counted again as the basis for its recommended cost of equity.

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

253. The Administrative Law Judge finds that the cost of equity of 9.18 percent recommended by the DOC-DER is fully supported by careful analysis based on the most relevant data available for consideration. The Administrative Law Judge

[327] *Id.* at 42-43.
[328] *Id.* at 40.

concludes that Great Plains' cost of equity should be set according to the analysis of the DOC-DER, with an adjustment to remove flotation costs.

XI. CAPITAL STRUCTURE

254. The overall cost of capital for Great Plains is its average of the costs of long-term debt, short-term debt, preferred stock and common equity that it faces, weighted by the amount of each type of financing that it uses. To arrive at the cost of capital (overall rate of return) for Great Plains, it is necessary to determine appropriate ratios of long-term debt, short-term debt, preferred stock and common stock equity that it uses as sources of financing.[329]

255. In Statement D of its filing, Great Plains submitted a proposed capital structure based on its actual capital structure for 12 months ending December 31, 2014, and projected 2015-2016.[330] In response to DOC-DER Information Request 29, Great Plains submitted the following updated projected 2016 capital structure:[331]

Great Plains Projected 2016 Capital Structure

	Initial Filing	Revised Response to DOC IR 209
Long-Term Debt	41. 250%	41.712%
Short-Term Debt	6.483%	6.556%
Preferred Stock	1.126%	1.146%
Common Equity	51.141%	50.586%
TOTAL	100.000%	100.000%

256. The DOC-DER compared Great Plains' updated capital structure to the average capital structures of the DOC-DER's proxy group as follows:[332]

Summary of Great Plains' Proposed Capital Structure and Capital Structures of DOC Proxy Group Members Great Plains

	Long-Term Debt Ratio	Short-Term Debt Ratio	Preferred Stock Ratio	Common Equity Ratio	Total
Great Plains	41.71%	6.56%	1.15%	50.59%	100.00%
ATO	40.20%	7.50%	0.00%	52.30%	100.00%

[329] Ex. 204 at 33 (Addonizio Direct).
[330] *Id.*; Ex. 2, Statement D (Application).
[331] Ex. 204 at 33 (Addonizio Direct).
[332] Ex. 204 at 34-35 (Addonizio Direct).

	Long-Term Debt Ratio	Short-Term Debt Ratio	Preferred Stock Ratio	Common Equity Ratio	Total
LG	49.20%	8.98%	0.00%	41.82%	100.00%
NWN	39.77%	14.11%	0.00%	46.12%	100.00%
SJ1	46.22%	11.13%	0.00%	42.25%	100.00%
SWX	52.89%	0.16%	0.00%	46.95%	100.00%
WGL	37.67%	12.91%	1.10%	48.33%	100.00%
DOC-DER Proxy Group Average	44.39%	9.13%	0.18%	46.29%	100.00%

257. The DOC-DER noted that, while Great Plains' 50.586 percent equity ratio in its updated filing was higher than the average of the DOC-DER's proxy group, it was within that group's range of equity ratios. While Great Plains' long- and short-term debt ratios were lower than the average, they were also within the range of the DOC-DER's comparable group. The DOC-DER concluded that Great Plains' revised capital structure was reasonable.[333]

258. While Great Plains believed that its original filed capital structure was appropriate, it accepted the reasonableness of the DOC-DER's suggested capital structure as shown in the Company's updated Table 5, with an equity ratio of 50.586 percent.[334]

259. The OAG contended that Great Plains' capital structure was not reasonable because its common equity ratio was higher than the average of Great Plains' proxy companies' equity ratios. The OAG recommended an equity ratio of 49.53 percent, to correspond with the average of Great Plains' proxy group.[335] The OAG argued that low cost debt has been available over the past few years, making it more prudent for Great Plains to finance capital expenditures with debt financing than equity.[336]

260. Great Plains disagreed with the OAG's recommendation to Great Plains to reduce the common equity ratio from 50.586 percent to 49.53 percent in its proposed capital structure, stating that the capital structure was comfortably within proxy Great Plains ratios and neither unusual nor extreme.[337]

261. The Administrative Law Judge agrees with the DOC-DER and Great Plains that the Company's updated capital structure is reasonable and should be adopted. The use of Great Plains' own updated information is preferable to applying the

[333] *Id.* at 35.
[334] Ex. 15 at 18 (Gaske Rebuttal).
[335] Ex. 100 at 25 (Lindell Direct).
[336] *Id.*
[337] Ex. 15 at 14 (Gaske Rebuttal).

company's proxy group ratios. Great Plains' proposed ratios fall within the range of ratios of the DOC-DER's proxy companies, all of which were thoroughly screened by the DOC-DER and found to be comparable with Great Plains. Although the OAG argued for a move from equity cost to debt, there is no evidence showing what the cost of debt would be currently or in the foreseeable future, or how a turn from equity financing to debt would affect Great Plains' cost of capital.

XII. SALES FORECAST: PROJECTED REVENUES

A. Sales Forecast and Weather Normalization

262. Accurately forecasting sales by developing an appropriate test year sales forecast is critical to calculating a utility's revenue requirement and determining just and reasonable rates.[338] If the forecast overestimates sales, rates will be set too low and Great Plains will not be able to recover the full cost of service. Conversely, if the forecast underestimates sales, rates will be set too high resulting in customers paying more than what is necessary for Great Plains to recover its costs. Therefore, it is necessary that the method used to forecast test year sales be reasonable.[339]

263. Test year sales volumes are based on historical utility data. In estimating test year sales volumes, expected usage per customer and expected customer counts are adjusted for known and measurable changes including an assumption that test year usage is based on "normal" weather conditions and other assumed normal conditions to eliminate the impacts of variable factors such as weather.[340]

B. Summary of Great Plains Test Year Sales Forecast

264. Great Plains provided a forecast of its sales volumes and associated sales revenues for test year 2016. Great Plains' test year sales forecast was derived by estimating usage of natural gas per customer for each customer class and estimating the number of customers in each class to predict total test year sales by class.[341] For each customer class, Great Plains calculated separate sales estimates for the North and South rate areas.[342]

265. To estimate its test year sales volumes for each class, Great Plains first "weather normalized" its sales volume data for each class to reflect sales occurring with normal weather based on a 30-year period of weather data from 1971-2000.[343] Great Plains then used statistical modeling based on three years of monthly sales volume

[338] Ex. 206 at 3-5 (Otis Direct).
[339] *Id.* at 5.
[340] Ex. 206 at 3 (Otis Direct).
[341] *Id.* at 7.
[342] *Id.* at 7-8.
[343] *Id.* at 11-12; Ex. 17 at 2-3 (McCullough Direct).

data (2012-2014) to predict test year sales volumes for heat sensitive customer classes (the residential, small firm and large firm classes).[344]

266. For customer counts forecasted by class, Great Plains calculated a growth rate based on three years of historical customer counts.[345]

267. From its estimated test year usage and customer counts, Great Plains forecasted its proposed total test year usage.[346] Great Plains estimated total system test year sales of approximately 7,315,488 therms.[347] Applying applicable tariffed rates for each of Great Plains' rate classes to its test year proposed sales volumes resulted in Great Plains' proposed total test year sales revenue of $24,158,706.[348]

C. The DOC-DER's Position

268. Great Plains and the DOC-DER are largely in agreement with respect to the sales forecast methodology used in this case.[349] However, the DOC-DER disputes the reasonableness of Great Plains' use of some data inputs in its test year forecast models.[350] Specifically, the DOC-DER maintains that Great Plains' use of a 30-year period (1971-2000), for weather data and only three years of historical sales volume data (2012-2014) to project test year sales for volumes was unreasonable.[351]

269. The DOC-DER contends that Great Plains' weather data is out-of-date and recommends using the most recent 16-year period for weather normalization.[352] The DOC-DER also recommends use of 12 years of sales volume to ensure a more reliable 2016 test year forecast.[353]

270. Based on 16 years of updated weather data and 12 years of sales data, the DOC-DER estimates a total test year revenue figure of $24,581,086, which results in an increase to test year revenue of approximately $422,380 over the Company's originally filed revenue estimate of $24,158,706.[354] The DOC-DER also determined that its test year sales estimate would increase fuel cost expenses by approximately $322,306 over the Company's original estimate. In addition, the DOC-DER determined that its test year sales estimates increase Conservation Improvement Program (CIP)

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[344] Ex. 206 at 8-9 (Otis Direct); Ex. 17 at 4 (McCullough Direct).
[345] Ex. 206 at 9 (Otis Direct); Ex. 17 at 3-5 (McCullough Direct).
[346] Ex. 206 at 7 (Otis Direct).
[347] Ex. 206 at 22 (Otis Direct); Ex. 3, Statement C-1 (Application); Ex. 8, Statement C-1 (Update to Base Cost of Gas).
[348] Ex. 206 at 22 (Otis Direct); Ex. 17 at 2-3 (McCullough Direct).
[349] Ex. 220 at 1 (Otis Testimony Summary); Ex. 206 at 6, 20 (Otis Direct); Evidentiary Hearing Tr. at 29 (McCullough).
[350] Ex. 206 at 6, 20, 23 (Otis Direct); Ex. 220 at 1 (Otis Testimony Summary).
[351] Ex. 206 at 6, 20, 23 (Otis Direct); Ex. 220 at 1 (Otis Testimony Summary).
[352] Ex. 206 at 22 (Otis Direct); Ex. 207 at 6 (Otis Rebuttal). In her direct testimony, Ms. Otis recommended use of the most recent 20-year period for weather normalization, but used a 16-year period due to lack of information provided by Great Plains.
[353] Ex. 206 at 13-14, 17, 21 (Otis Direct).
[354] Ex. 206 at 23-24 (Otis Direct); Ex. 207 (Otis Rebuttal); Ex. 208 at 5 (Otis Surrebuttal).

revenues by $4,190 over the Company's original estimate. Therefore, after accounting for increased natural gas cost expenses and CIP revenues, the DOC-DER's total revenue calculation is approximately $85,884 greater than the Company's originally filed revenue estimate.[355]

D. 30-Year vs. 16-Year Weather Normalization for Sales Forecast

271. Because weather is a significant factor affecting sales, data used to estimate test year sales are adjusted to reflect sales that likely would exist in a year that had "normal" weather conditions. This is called "weather normalizing."[356]

272. The length of weather normalization can be very influential on the overall sales forecast. Weather normalization adjusts historical sales volumes to account for weather variations, and has recently been an issue in utility sales forecasting applications.[357]

273. Great Plains used a 30-year period, 1971-2000, to normalize the weather forecast for the test year.[358]

274. The DOC-DER maintains that use of a 30-year period to determine normal temperatures for forecasting test year sales volumes is not reasonable given the climate's recent and increasing warming.[359] The DOC-DER contends that use of such a long period for normalization may inaccurately forecast cooler weather.[360]

275. In support of its criticism of the Great Plains' proposed 30-year period, the DOC-DER cites to an article published in the May 2013 edition of *Public Utility's Fortnightly*, entitled "Redefining Normal Temperatures: Resource planning and forecasting in a changing climate."[361] The article, written by Robert Livezey and Phillip Hanser, asserts that averaging temperatures over 30 years to produce normal temperature estimates would be reasonable *if* the climate were stationary or unchanging.[362] The climate, however, is not stationary.[363] Because the climate has been warming "at a moderate to rapid rate," the authors conclude use of a 30-year period would bias the result and can no longer be considered representative of the current climate.[364] One way to reduce a cold bias for weather normalization is to use a

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[355] Ex. 206 at 23-24 (Otis Direct); Ex. 207 (Otis Rebuttal); Ex. 208 at 5 (Otis Surrebuttal).
[356] Ex. 206 at 4 (Otis Direct).
[357] Ex. 207 at 6 (Otis Rebuttal); *see also* CENTERPOINT PUC ORDER at 62 (given the uncertainty regarding the best method for estimating "normal" weather, the Commission reaffirmed the requirement that companies examine 10-, 15-, and 20-year weather data in future cases).
[358] Ex. 206 at 15, LBO-1 (Otis Direct).
[359] Ex. 206 at 12-15 (Otis Direct).
[360] *Id*.
[361] *Id.*
[362] *Id*.
[363] *Id*.
[364] *Id*.

shorter than 30-year average.[365] The authors cite to a number of studies and other recent evidence that suggest that, overall, the best averaging period is 15 years.[366]

276. The DOC-DER also objects to Great Plains' use of data from 1971-2000 because it fails to include actual weather data from the most recent 15 years (2001-2015). The DOC-DER asserts that, for predicting future events, it is preferable to use updated (recent) data rather than rely on old data. The DOC-DER maintains that recent data is more likely to produce forecast results that are accurate and reliable, especially for weather data as the climate has trended towards warmer weather in recent decades.[367] The DOC-DER also notes that in recent years it is now common for utilities to use a shorter time period, such as 10- or 20-year periods, when predicting future weather patterns.[368]

277. The DOC-DER proposed use of a 20-year period to normalize weather. However, because Great Plains was unable to provide the DOC-DER with a bill cycle prior to 1999, the DOC-DER ultimately used 16 years of data, from 1999-2015, to estimate "normal" weather.[369]

278. Great Plains objects to the DOC-DER's use of a 16-year period to normalize weather. Great Plains contends that such a short period of time allows for greater fluctuations in temperature due to unseasonable warm or cold weather patterns.[370] Great Plains maintains that use of a 30-year average for temperatures smooths out anomalies and results in a more accurate normal average temperature.[371]

279. The Administrative Law Judge is persuaded by the reasoning of the DOC-DER's expert, Ms. Otis, and finds that Great Plains did not meet its burden to show use of an outdated 30-year period for weather normalization to be reasonable. The Administrative Law Judge agrees with the DOC-DER that use of the most recent 16-year period (1999-2015) to estimate normal weather is likely to be representative of temperatures for the 2016 test year and therefore is reasonable and should be used in this case.

E. 3-Years vs. 12-Years of Historical Sales Volumes

280. The DOC-DER criticizes Great Plains for using only three years of historical sales data to forecast the likely test year sales volumes.[372] Great Plains used monthly sales volumes from 2012, 2013, and 2014 in its regression analysis to estimate sales volumes for 2015 and 2016.[373] The DOC-DER maintains that a larger dataset

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[365] *Id*. at 31.
[366] *Id*. at 31-32.
[367] *Id.* at 15.
[368] *Id.* at 15, LBO-4; *see* also CENTERPOINT PUC ORDER at 62.
[369] Ex. 206 at 22 (Otis Direct); Ex. 207 at 6 (Otis Rebuttal).
[370] Ex. 18 at 2-3 (McCullough Rebuttal).
[371] *Id*.
[372] Ex. 206 at 14-15 (Otis Direct).
[373] *Id*.

renders more reliable results by decreasing the risk of creating an inaccurate model based on outliers, such as an unusually warm year, or faulty observations.[374]

281. The DOC-DER recommends using 12 years of sales volume data, from 2004-2015, to forecast test year sales volume.[375]

282. Great Plains opposes extending the historical sales data set to 12 years. The Company maintains that use of 12 years of historical sales data may inaccurately forecast higher gas usage per customer than what is actually occurring by not properly accounting for recent and continuing achievements in energy conservation, such as the building of more energy efficient homes and use of more energy efficient appliances.[376] Great Plains contends that use of three years of historical data in its regression modeling more accurately forecasts gas usage by eliminating the higher consumption levels of ten years ago.[377]

283. The DOC-DER disagrees with Great Plains and points out that conservation programs are typically phased in gradually as customers take advantage of the programs.[378] For example, if customers are motivated to install more energy efficient heating systems, the effect will be gradual as customers typically take advantage of these programs only when their old system is in need of replacement.[379] Because of the gradual, linear nature of conservation programs, the DOC-DER asserts that 12 years of historical data will accurately take into account the effect of energy conservation.[380]

284. In response, Great Plains asserts that by using 12 years of historical data, the DOC-DER fails to recognize the more aggressive conservation requirements that have been mandated in recent years, including (CIP) and energy efficiency mandates that are reflected in Minn. Stat. § 216B.241 (2014).[381] Such mandates include increased minimum annual energy savings goals[382] and a requirement for utilities to implement CIP that are expressly designed to achieve energy efficiency goals consistent with the Sustainable Building 2030 performance standards.[383] Great Plains insists that the impact of such requirements over time is not adequately reflected in data that is more than a decade old and, as a result, will not accurately capture the decreasing use per customer that Great Plains has recently experienced because of energy efficiency measures and conservation.[384]

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[374] *Id*.
[375] *Id*. at 14, 21, 23 and LBO-10.
[376] Ex. 18 at 2 (McCullough Rebuttal).
[377] *Id*.
[378] Ex. 208 at 2-3 (Otis Surrebuttal).
[379] *Id*.
[380] Ex. 208 at 3 (Otis Surrebuttal).
[381] Great Plains Initial Post-Hearing Br. at 34.
[382] Minn. Stat. § 216B.241, subd. 1(c).
[383] Minn. Stat. § 216B.241, subd. 9(e).
[384] *Id*.

285. In addition, Great Plains notes that recalculating its regression model with four-and-a-half years of historical data did not have a significant impact on the test year results.[385] According to Great Plains' expert, Cameron McCullough, use of four and a half years of historical data (July 2011-December 2015) and the 30-year rolling-average normal temperatures resulted in an adjustment within 1.0 percent of test year sales and 1.75 percent of total test year revenue. Therefore, Great Plains recommends that the Commission accept its test year sales volume and revenue forecasts as originally filed.[386]

286. The Administrative Law Judge finds Great Plains has not shown that use of only three years of sales volume data to estimate test year sales volume is reasonable. Based on this record, the Administrative Law Judge is persuaded that use of 12 years of sales volumes will provide a more reliable 2016 test year forecast and recommends the Commission adopt use of twelve years of historical sales volumes to forecast the test year sales.

XIII. RATE DESIGN

A. Introduction

287. Rate design is the second step of the two-step rate making process. In the first step, the Commission determines the revenue requirement, which is quasi-judicial and fact intensive. The second step, designing rates to charge customers, is largely a quasi-legislative function. The second step of rate making largely involves facts, it also involves policy decisions.[387]

288. Both courts and the Commission have recognized that appropriate rate design requires consideration of cost and non-cost factors.[388]

289. Minnesota law requires that every rate must be just and reasonable.[389] The Commission has relied on the following principles in designing reasonable and just rates:

1) Rates should be designed to allow Great Plains a reasonable opportunity to recover its revenue requirement, including the cost of capital;

2) Rates should promote efficient use of resources by sending appropriate price signals to customers, reflecting the costs of

[385] Ex. 18 at 3 (McCullough Rebuttal).
[386] *Id*. at 4.
[387] *See In re Request of Interstate Power Co. for Auth. to Change Rates for Gas Serv. in Minn.* (*Interstate Power*), 559 N.W.2d 130, 133 (Minn. Ct. App. 1997), *aff'd* 574 N.W.2d 408 (Minn. 1998).
[388] Ex. 18 at 4 (McCullough Rebuttal).
[389] Minn. Stat. § 216B.03.

serving them. For example, an appropriate price signal encourages conservation by customers;

3) Rate changes should be gradual so as to limit rate shock to consumers. Rate stability and continuity are important to both the utility and the consumer; and

4) Rates should be understandable and easy to administer. Maintaining ease in administration helps ensure that customers understand their utility bills better.[390]

B. Legal Standards Reflected in Rate Design Principles

290. The same basic legal standards apply to both steps of the two-step rate-setting process. When seeking to change its rates, a public utility has the burden to show that its requested rate change is just and reasonable.[391]

291. Rates also must encourage energy conservation to the maximum reasonable extent. Any doubt regarding the reasonableness of a particular rate must be resolved in the consumer's favor. Where different rates appear to be equally valid, the Commission must choose the rate (including the rate design) that favors the ratepayer.[392]

292. Minnesota law prohibits public utilities from charging unreasonably discriminatory rates.[393] Similarly, a "public utility [shall not], as to rates or service, make or grant any unreasonable preference or advantage to any person or subject any *person* to any unreasonable prejudice or disadvantage."[394] The Commission is also required to consider the ability to pay as a factor when setting public utility rates.[395]

293. Because rates differ among the various classes of service, the DOC-DER concluded and the Administrative Law Judge agrees that there must be a cost basis for any differences to be deemed reasonable, unless one of the rate-design principles above is used to adjust rates.[396]

C. Class Cost of Service

1. Introduction

294. A Class Cost of Service Study (CCOSS) is designed to identify the cost responsibility, as accurately as possible, of each customer class for each cost incurred

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[390] Ex. 211 at 22-23 (Heinen Direct).
[391] Minn. Stat. § 216B.16, subd. 4 (2014).
[392] Minn. Stat. § 216B.03.
[393] Minn. Stat. § 216B.03; Ex. 211 at 24 (Heinen Direct).
[394] Minn. Stat. § 216B.07 (2014).
[395] Minn. Stat. § 216B.16, subd. 15 (2014).
[396] Ex. 211 at 24-25 (Heinen Direct).

by the utility in providing service. Costs can then be allocated equitably among all customer classes according to the principle of cost causation. A CCOSS derived in this manner can be used as one factor in determining how costs should be recovered from customer classes through rate design.[397]

295. A properly developed CCOSS should reflect cost causality and nothing more. Judgments and decisions regarding the application of the CCOSS are made in the rate design process.[398]

296. Development of a CCOSS is comprised of three steps: 1) functionalization, the assignment of revenue requirements to specified utility factions, based on their purpose; 2) classification, a refinement of the functionalization to identify the utility operation on which the various functionalized dollars are spent; and 3) allocation to customer classes according to their cost impact on the system.[399]

297. Functionalized costs are classified as follows:

1) Customer costs are determined by the number of customers on the system, regardless of their energy consumption. Examples include metering and billing.

2) Energy or commodity costs are comprised of the cost of variable expenses used in the production of gas. These costs rise as a customer uses more volumes of natural gas.

3) Demand costs vary with the quantity or size of the utility's plant. These costs are related to maximum system requirements for which the system is designed during times of maximum demand, and do not vary with the number of customers. Examples are capital costs and expenses of the distribution system in excess of the minimum size, such as peak shaving facilities and central parts of the utility's distribution system.[400]

298. Classified costs are allocated to customer classes based on each class's individual contribution to the cost as follows:

1) Customer costs are generally allocated to customer classes by the number of customers in the class and the level of costs such as metering for the particular class.

2) Demand costs are allocated to the customer classes based on the demand imposed by the class during specific peak hours.

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[397] Ex. 209 at 3-4 (Ruzycki Direct).
[398] *Id.* at 4.
[399] *Id.*
[400] Ex. 209 at 5-6 (Ruzycki Direct).

3) Energy or commodity costs are allocated among the customer classes based on the energy the system must supply to serve each class.[401]

299. Great Plains filed a CCOSS at Ex. 3, Initial Filing Work Papers Statement E.

2. Great Plains CCOSS

300. Great Plains filed its CCOSS using a minimum system analysis to classify the costs of its distribution mains between demand-related and customer-related costs.[402]

301. According to the *National Association of Regulatory Utility Commissioners* (NARUC) *Gas Manual*, distribution plant investments may be classified as both demand and customer costs. The minimum size of the utility's distribution plant equipment is the basis of the bifurcation of customer and demand costs in the minimum size method of classifying these investment costs.[403]

302. The rationale for this separation under the minimum system or minimum size analysis is that the utility's distribution system constructed of minimum size main should be sufficient to deliver service to customers. Any distribution costs in excess of the hypothetical minimum system are assumed to vary with demand and thus are demand-related costs. [404]

303. Great Plains chose a two-inch plastic main pipe for its minimum system analysis.[405] Great Plains then calculated the cost of its minimum system (customer component of mains) as if all mains were only two-inch mains. It did so by multiplying the total length of all steel and plastic mains by the Company's assumed $11 cost per foot of two-inch and less mains. [406]

304. Finally, Great Plains divided the minimum system cost it had developed by the total system cost, which provided the percentage of distribution mains attributable to connectivity of customers (66.74 percent customer-related), with the remainder (33.26 percent) assumed to be demand-related.[407]

305. In response to a DOC-DER Information Request, Great Plains later revised its minimum size analysis using updated main cost data. The updated data was

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[401] *Id.* at 7.
[402] Ex. 25 at 6-7 (Aberle Direct).
[403] Ex. 209 at 12-13 (Ruzycki Direct) (citing *1989 Gas Distribution Rate Design Manual of the National Association of Regulatory Utility Commissioners* (*Gas Manual*) at 32-33).
[404] Ex. 209 at 13 (Ruzycki Direct).
[405] Ex. 25 at 6 (Aberle Direct).
[406] Ex. 209 at 26-27 (Ruzycki Direct).
[407] *Id.* at 27.

based on a sample of work orders from Great Plains and Montana-Dakota Utilities Co., its sister-subsidiary of MDU.[408]

306. At the conclusion of its analysis, Great Plains essentially reversed the customer and demand components so that it proposed a customer-related cost of 25 percent and a demand-related cost of 75 percent.[409] Great Plains explained the change only by stating that "Great Plains chose to utilize a more conservative approach by allocating only 25 percent to the customer component."[410]

307. In Surrebuttal Testimony filed in response to the DOC-DER's and the OAG's recommendations to reject the Company's CCOSS, Great Plains offered an alternative CCOSS with 100 percent of the distribution mains account classified as demand.[411]

308. Great Plains also agreed with the DOC-DER's alternative CCOSS.[412]

309. Great Plains defended its filed CCOSS as appropriately containing disaggregated cost data. Great Plains stated that it used replacement cost per foot for its two inch pipe and then compared that cost to the cost of replacing all other pipe based on current pipe sizes used according to current installation standards.[413]

3. Issues Raised by the DOC-DER and the OAG.

a. The DOC-DER

310. The NARUC *Gas Manual* states in part:

> Under the minimum size main theory, all distribution mains are priced out at the historic unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution mains is assigned to demand.[414]

311. Although Great Plains provided data regarding the total footage of its mains, the DOC-DER testified that the Company's cost data was insufficiently granular. The DOC-DER stated that Great Plains' disaggregated distribution main cost data did not provide the DOC-DER the information that it needed to verify and reproduce the company's minimum size analysis.[415]

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[408] *Id.* at 28.
[409] Ex. 25 at 7 (Aberle Direct).
[410] *Id.*
[411] Ex. 28 at 5 (Aberle Surrebuttal).
[412] *Id.* at 2.
[413] *Id.* at 3.
[414] Ex. 209 at 20 (Ruzycki Direct) (citing *Gas Manual* at 22-23).
[415] Ex. 210 at 8 (Ouanes Surrebuttal).

312. The DOC-DER contended that Great Plains was also unable to support its aggregated distribution main cost data from its filing. The DOC-DER noted that Great Plains responded to its request for further information with a filing based on a sample of its work orders.[416]

313. Great Plains did not indicate whether the aggregated cost per foot distribution costs it provided in response to DOC-DER requests represented installed costs, unit costs, vintage, or current costs.[417] Because Great Plains' distribution system consists of mains of various sizes, materials (steel or plastic), and vintages, it is difficult to confirm the company's use of cost data in its study. [418]

314. The DOC-DER did not agree with Great Plains' significant shift of customer- and demand-related costs at the close of its minimum size analysis. Although the DOC-DER understood the Company's desire to moderate customer costs for the purpose of rate design, that intention should be pursued during the development of rate design in the rate case, not overlaid on the CCOSS analysis.[419]

315. The DOC-DER recommended rejection of an alternative CCOSS filed by Great Plains in Surrebuttal Testimony based solely on demand costs as being unsupported in the record.[420]

316. The DOC-DER stated that Great Plains' development of its minimum size analysis would have a substantial impact on its proposed CCOSS.[421]

317. The DOC-DER recommended rejection of Great Plains' CCOSS both as originally filed and as revised for lack of proof as to its reasonableness because the Company's underlying data was insufficient.[422] In the event that the Commission deems the information, assumptions, and methodologies of the Company's CCOSS sufficient, the DOC-DER recommended that the Commission adopt the DOC-DER's alternative CCOSS.[423] The DOC-DER's alternative CCOSS incorporates Great Plains' updated cost figures and accurately applies the classification of distribution plant costs from the Company's minimum system analysis, thus eliminating Great Plains' shift of customer- and demand-related costs.[424]

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[416] Ex. 210 at 8 (Ouanes Surrebuttal); Ex. 209 at 18 (Ruzycki Direct).
[417] Ex. 209 at 19 (Ruzycki Direct).
[418] *Id.* at 16-19.
[419] *Id.* at 31.
[420] Ex. 221 at 2 (Ouanes Testimony Summary).
[421] Ex. 210 at 8 (Ouanes Surrebuttal).
[422] *Id.* at 10.
[423] *Id.*
[424] Ex. 209 at 32-33 (Ruzycki Direct).

318. The DOC-DER testified that the Commission's rejection of the Company's CCOSS would mean that the CCOSS would not be available as one of the factors in this proceeding by which the Commission would determine a reasonable rate design.[425]

319. The DOC-DER recommended that the Commission require Great Plains to make the following changes in its next rate case filing:

1) Provide and use non-aggregated distribution mains data (length in feet, original cost of construction and normalized replacement cost) per material, size and vintage (year) in support of its minimum size analysis;

2) Submit a CCOSS for each individual rate area if the rate areas have not been consolidated by the time of the rate case filing.[426]

b. The OAG

320. The OAG addressed the DOC-DER's analysis of the company's CCOSS.[427] The OAG had no concerns with the DOC-DER's underlying analysis of the poor quality of the data underlying the Company's CCOSS. However,the OAG recommended that the Commission reject both Great Plains' CCOSS and the DOC-DER's alternative CCOSS.[428]

321. The OAG could not support the Company's CCOSS because of the gravity of the DOC-DER's concerns with it. The OAG could not support the alternative CCOSS because it relies on analysis by the Company that the DOC-DER calls into question.[429]

322. The OAG recommended that the revenue apportionment currently embodied in Great Plains' rates continue without modification. If the Commission determines that a rate increase is warranted, the OAG recommends that the increase be applied evenly across all customer classes.[430]

c. Findings and Conclusions

323. Great Plains has filed a CCOSS with insufficient supportive data. In addition the Company made unexplained changes to its analysis during the proceeding, such as its transposition of demand- and customer-related costs in Rebuttal Testimony and its filing of a new analysis based solely on demand costs in Surrebuttal Testimony.

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[425] Ex. 210 at 9 (Ouanes Surrebuttal).
[426] *Id.* at 10.
[427] Ex. 101 at 2 (Lindell Rebuttal).
[428] *Id.* at 2-4.
[429] *Id.* at 3-4.
[430] *Id.*

324. Great Plains filed updated cost data which applied to actual quantities of main installed. The DOC-DER applied those data to create an alternative CCOSS but found the data insufficient for a thorough analysis based solely on the provided data.

325. The record supports the position of the DOC-DER and OAG that Great Plains did not show the reasonableness of its initially proposed CCOSS and that the Company's Rebuttal and Surrebuttal Testimonies did not address the CCOSS-related concerns raised by the DOC-DER and the OAG.

326. For these reasons, the Administrative Law Judge recommends that the Company's CCOSS be rejected by the Commission.

327. The Administrative Law Judge concludes that the DOC-DER's alternative CCOSS, while imperfect, may be useful to the Commission in proceeding toward the development of rate design. The Commission and all parties should be aware of the weakness of the alternative CCOSS and weigh it accordingly as a factor in rate design determination.

328. The Administrative Law Judge also recommends that Great Plains be required to make the DOC-DER's recommended changes to its CCOSS in its next rate case.

D. Revenue Apportionment

329. Once the Commission determines how much a utility may receive from its customers in rates, the total sum or revenue requirement is apportioned to customer classes in order to determine how much of that sum each class will be charged.[431]

330. Rates should be fair. The most objective way to define "fair" is that each class of customers should pay enough to cover its share of costs.[432]

331. An inter-class subsidy occurs when the revenue responsibility apportioned to a class of customers fails to recover the cost of serving those customers, and the difference is made up by over-recovering from other customer classes.[433]

332. In addition to rate fairness, minimizing such inter-class subsidies is important because it provides customers accurate information about the cost of natural gas service so they can make informed decisions about how much to use. This price information is often called "price signals".[434]

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[431] Ex. 212 at 37 (Heinen Direct).
[432] Id. at 40.
[433] Id. at 40.
[434] Id at 40.

333. Based on its original CCOSS, Great Plains identified which classes it believes should receive an increase in rates and the magnitude of the increases to more closely align cost recovery with cost causation, a primary rate design objective.[435]

334. Great Plains' CCOSS showed large commercial and industrial rates to be above fully distributed embedded cost and residential and firm general service rates to be below fully distributed embedded cost. The resulting returns by customer class are shown below:[436]

Residential Service	-6.449%
Small Firm General Service	5.615%
Large Firm General Service	4.839%
Small Interruptible Sales	59.323%
Small Interruptible Transportation	77.631%
Large Interruptible Sales	84.576%
Large Interruptible Transportation	24.728%

335. The Company's proposed revenue requirement increase was apportioned by first allocating the overall increase of 6.44 percent to the Firm General Service, 3.00 percent to the Small Interruptible Sales, Small Interruptible Transportation, Large Interruptible Sales and Large Interruptible Transportation classes with the exception of the Large Interruptible Transportation services provided at a contract rate. The remainder of the total increase was allocated to the residential class. This resulted in an average increase of 8.76 percent being allocated to the residential class.[437]

336. The DOC-DER evaluated the Company's proposed apportionment of revenue responsibility by comparing the current and proposed revenue requirement responsibilities with the results of the Company's proposed CCOSS to determine which customer classes are substantially below their respective costs of service, and which classes are contributing revenues in excess of their costs of service, thus resulting in an inter-class subsidy.[438]

337. In addition the DOC-DER reviewed the revenue contributions from customer classes with bypass options to ensure that the rates and revenue contributions remain competitive.[439]

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[435] "[T]he Commission puts substantial weight on cost causation in determining what portion of the total revenue requirement each customer class should pay." *In re Petition by Minn. Energy Res. Corp. for Authority to Increase Natural Gas Rates in Minn.,* PUC Docket No. G-011/GR-13-617, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 42 (Oct. 28, 2014).
[436] Ex. 25 at 4 (Aberle Direct); *see also* Ex. 8, Schedule E-2a at 1-4 (Application).
[437] *Id*.
[438] Ex. 212 at 39 (Heinen Direct).
[439] *Id.* at 39.

338. The DOC-DER recommended that if the Commission determined that Great Plains' CCOSS is acceptable, the Commission adopt the Company's originally filed proposed apportionment.[440]

339. However, the DOC-DER alleged numerous flaws in the Company's CCOSS and concluded that the Company did not show the reasonableness of its CCOSS.[441] As a result, in Direct Testimony, the DOC-DER proposed an alternative to the Company's CCOSS.[442]

340. The DOC-DER did not recommend a specific revenue apportionment based upon its proposed alternative CCOSS. Nor did any other party.

341. Ultimately, in Surrebuttal Testimony, the DOC-DER withdrew its proposed alternative and urged the Commission to reject Great Plains' CCOSS. In the event that the Commission agrees and rejects all CCOSS proposals, the DOC-DER recommended that any rate increase approved by the Commission be spread evenly across customer classes.[443] The OAG also supported this approach.[444]

342. If there is not a valid CCOSS in this proceeding, apportioning the responsibility to the revenue deficiency equally across each revenue class is an acceptable method to deal with recovery of the revenue deficiency. In effect, this approach is based on the CCOSS approved in Great Plains' prior rate case.[445]

343. In the event that the Commission adopts use of the DOC-DER's alternative CCOSS, the Administrative Law Judge recommends that the Commission adopt a revenue apportionment proposal that moves ratepayers closer to cost.

E. Customer Charge

1. Proposed Increases

344. Great Plains proposed two types of changes to its Basic Service Charges: 1) increases to all Firm and Interruptible rate classes, although no change to the Large Interruptible Transportation class; and 2) a change in how to recover those charges from firm customers (Residential and General Service): from a monthly to a daily basis method.[446]

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[440] Ex. 213 at 43-44 (Heinen Direct).
[441] EX. 25-32 (Ruzcycki Revised Direct)
[442] Ex. 25 at 32(Ruzcycki Revised Direct)
[443] Ex. 214 at 2-3 (Heinen Surrebuttal).
[444] Ex. 101 at 4 (Lindell Rebuttal).
[445] *Id.*and Ex. 101 at 4 (Lindell Rebuttal).
[446] Ex. 211 at 47-48 (Heinen Direct).

345. The fixed Basic Service (Customer) Charge is one component of a two-part or three-part rate for a class of customers. This fixed charge covers things such as the cost of the meter and the cost to prepare and send out bills.[447]

346. An increase or decrease in a customer charge has no impact on the revenue apportionment (or deficiency) since there is a corresponding decrease or increase, respectively, in the volumetric rate proposed for the given rate class.[448]

347. Nonetheless, the Commission has considered the Residential Customer Charge on a stand-alone basis with respect to the concept of rate shock.[449]

348. Residential customers may not understand that a large increase in the fixed customer charge may be accompanied by a lower volumetric charge (relatively speaking) for the gas commodity.[450]

2. The Amount of the Basic Service Charge

349. Great Plains proposes to increase the Basic Service Charge for residential customers from $6.50 per month to $0.296 per day (or approximately $9.00 per month), the small general service Basic Service Charge from $20 per month to $25 per month and the large general service Basic Service Charge from $25 per month to $50 per month.[451]

350. The Basic Service Charges applicable to Small Interruptible Sales Rate and Small Interruptible Transportation Service Rate are proposed to increase by $75.00 per month resulting in a Basic Service Charge of $200.00 for the sales service and transportation service. The Basic Service Charge for the Large Interruptible Sales Rate is proposed to increase to $250.00 per month representing an increase of $50.00 per month and the Large Interruptible Transportation Service Rate Basic Service Charge is proposed to remain at $250.00 per month.[452]

351. Great Plains generated the table below to illustrate the difference between the Company and the Department's proposed Basic Service Charge changes:

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[447] *Id*. at 45 (Heinen Direct).
[448] *Id* at 52.
[449] Ex. 211 at 49 fn 9 (Heinen Direct); Ex. 213 at 29 (Heinen Surrebuttal).
[450] Ex. 211 at 49 fn 9 (Heinen Direct).
[451] Ex. 25 at 11-12 (Aberle Direct).
[452] *Id.* at p. 12.

Customer Class	Current	GPNG Proposed	DOC Alternative
Residential	$6.50/Month	$0.296 per day ($9.00/Month average monthly charge over 365 day period)	$8.25
Firm General Service (<500 cubic feet/hour)	$20.00	$0.822 per day ($25.00 average monthly charge over 365 day period)	$25.00
Firm General Service (>500 cubic feet/hour)	$25.00	$1.644 per day ($50.00 average monthly charge over 365 day period)	$40
Small Interruptible Gas Service	$125.00	$200.00	$175.00
Small Interruptible Transport	$125.00	$200.00	No Increase.
Large Interruptible Sales	$200.00	$250.00	No increase.
Large Interruptible Transport	$250.00	$250.00	No increase.

352. DOC-DER summarized the Company's proposed increases in its Basic Service Charge, and explained the DOC-DER's recommendation to decrease the proposed change for three classes: Residential, Firm General Service greater than 500 cubic feet per hour, and Small Interruptible Service.[453]

353. DOC-DER provided a table to show the Basic Charge changes proposed by the Company, as follows:

[453] Ex. 211 at 47-59 (Heinen Direct).

Great Plains' Current and Proposed Basic Service Charges[454]

Customer Class	Customer Cost[455]	Current Basic Service Charge	GPNG Proposal[456]	Percentage Increase
Firm:				
Residential	$23.00/Month	$6.50/Month	$0.296 per day ($8.88/Month assuming 30 day month)	36.62%
Firm General Service (<500 cubic feet/ hour)	$27.42	$20.00	$0.822 per day ($24.66 assuming 30 day month)	23.30%
Firm General Service (>500 cubic feet/ hour)	$75.10	$25.00	$1.644 per day ($49.32 assuming 30 day month)	97.28%
		Interruptible		
Small Interruptible Gas Service	$177.78	$125.00	$200.00/Month	60%
Large Interruptible Gas Service	$305.25	$200.00	$250.00	25%
		Transportation		
Small Interruptible Gas Transport Service	$199.52	$175.00	$200.00	14.29%
Large Interruptible Gas Transport Service	$254.41	$250.00	$250.00	0.00%

354. The OAG opposes any increases in the Basic Service Charges for residential and small business customers on the basis that the increases: (1) would result in rate shock; and (2) are contrary to considerations such as affordability and energy conservation.[457] The OAG also asserts that the Company's proposed

[454] Ex. 211 at 46 (Heinen Direct).
[455] Ex. 211 at AJH-18 (Heinen Direct).Customer Cost data provided in the Company's response to DOC Information Request No. 701.
[456] Ex. 25 at 12 (Aberle Direct).The Company proposes the following monthly equivalent charges for its firm classes: $9.00 for the Residential Class, $25.00 for the Firm General Service less than 500 cubic feet per hour, and $50 for the Firm General Service greater than 500 cubic feet per hour.
[457] Lindell Direct at pp. 19-21; Lindell Surrebuttal at p. 9.

decoupling mechanism is an effective alternative to increased customer charges because a decoupling mechanism would stabilize revenues.[458]

355. Great Plains asserts that it has proposed increasing the amount recovered under the Company's Basic Service Charges to move toward a fully compensatory fixed charge rate. Great Plains position for the increased amounts to be collected through the Basic Service Charge is based on the customer component identified in its CCOSS.[459]

356. The Company testified that its proposal appropriately mitigates rate shock by not implementing a fully compensatory fixed charge at this time.[460]

357. Increasing customer charges closer to the level of fixed costs promotes equity by eliminating intra-class subsidies. As the Commission explained:

> Customer charges play an important role in the rate structure. They reduce utilities' capital costs by ensuring baseline levels of revenue, thereby reducing consumers' rates. They help mitigate rate volatility between seasons by recovering some fixed costs during the low-usage, summer months. They promote equity by ensuring that the rate structure does not shift the full system-costs imposed by low-usage and seasonal customers to normal-usage, high-usage, and year-round customers.[[461]]

358. In accepting past customer charge increases, the Commission has acknowledged that "customer charges constitute just a fraction of customers' bills."[462]

359. The DOC-DER provided data that showed the largest percentage increase to a residential customer charge approved by the Commission since the 2002 Great Plains' increase, which came after an 18 year period between rate cases, was $1.75 or approximately 32 percent for Minnesota Energy Resources Corporation (MERC) in 2008. The average increase was approximately $0.93 with an average percentage increase of approximately 14.25 percent.[463]

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[458] Lindell Direct at p. 21.
[459] Aberle Direct at p. 12.
[460] *Id.*
[461] *In the Matter of an Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Natural Gas Service in the State of Minnesota,* Docket No. G-002/GR-04-1511, Order Accepting and Modifying Settlement and Requiring Compliance Filings at p. 7 (August 11, 2005).
[462] *See e.g., In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rates in Minnesota,* MPUC Docket No. G-008/GR-08-1075, Findings of Fact, Conclusions of Law, and Order at p. 57 (January 10, 2010).
[463] Ex. 212 at 51 (Heinen Direct).

360. The DOC-DER argued that an approximately $2.38 increase or 36.6 percent increase, in the residential charge as proposed by the Great Plains may lead to rate shock.[464]

361. The DOC-DER supported an increase in order to bring the Basic Service Charge closer to the customer cost for each class, and agreed with the Company that increasing the customer charges would reduce intra-class subsidies within these customer classes.[465] In Surrebuttal Testimony, the DOC-DER did not reverse its position with regard to bringing the Basic Service Charges closer to cost for each class. However, the DOC-DER did note that since it recommends rejection of the proposed CCOSS, it did not recommend using the CCOSS to determine an appropriate increase to the Basic Service Charges.[466]

362. The DOC-DER proposed changes to Great Plains' proposed customer charges as illustrated by the table below:

Table 8: Proposed Changes in Basic Service Charges[467]

Customer Class	Current	GPNG Proposed	DOC Alternative
Residential	$6.50/Month	$0.296 per day ($8.88/Month assuming 30 day month)	$8.25
Firm General Service (<500 cubic feet/hour)	$20.00	$0.822 per day ($24.66 assuming 30 day month)	$25.00
Firm General Service (>500 cubic feet/hour)	$25.00	$1.644 per day ($49.32 assuming 30 day month)	$40
Small Interruptible Gas Service	$125.00	$200.00	$175.00

363. Based on the gradual historical increases generally approved by the Commission and considering the fact that it has been over a decade since Great Plains' last rate filing, the DOC-DER concluded that a $1.75 is not likely to constitute rate shock and would allow the residential customer charge to move closer to cost.[468]

364. The DOC-DER's proposal moves customer charges closer to cost while likely avoiding rate shock. Therefore, the Administrative Law Judge recommends that

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[464] Ex. 212 at 51 (Heinen Direct).
[465] Ex. 212 at 51-52 (Heinen Direct).
[466] Ex. 213 at 26 (Heinen Surrebuttal).
[467] Ex. 212 at 49 (Heinen Direct).
[468] Ex. 212 at 52 (Heinen Direct).

the Commission approve increases in accordance with the DOC-DER's recommendations.

3. Conversion to Daily Rate

365. In conjunction with its proposed increases in monthly Basic Service Charges, for the Service Charges applicable to the Residential and Firm General Service classes, Great Plains proposed to convert the monthly charge to a daily charge. The proposed change would equate to a charge of $0.296/day for the residential class; $0.822/day for Firm General Service (< 500 Cubic Feet); and $0.1644/day for the Firm General Service (> 500 Cubic Feet).[469]

366. Great Plains argued that charging such fixed costs on a daily basis better matches the way customers are billed in that, the days between billing periods vary due to meter reading cycles and customer cut-ins and cut-outs occurring outside their normal billing cycle.[470]

367. The DOC-DER opposed the Company's proposal primarily on the basis that it would add needless complexity to bills, which the DOC-DER argued does not conform to the Commission's rate design goals.[471]

368. Great Plains asserts that bills for service outside a normal period are currently normalized but the customer cannot readily determine how the bill was determined. A daily Basic Service Charge will allow the customer to simply multiply the number of days in service during the current billing period (now shown on the bill) times the applicable Basic Service Charge.[472]

369. There is no appreciable difference in the amount of revenue recovered under the Company's proposal and its current recovery method.[473]

370. Great Plains has not shown that this method would provide a significant benefit to ratepayers. Considering the rate and other changes likely to result from this proceeding, a change to the ratepayers' current billing protocol may add confusion and unintentionally appear to obfuscate rather than clarify any rate changes.

371. The Administrative Law Judge recommends that the Commission not approve Great Plains' proposal to convert its current fixed basic monthly service charge to a daily charge.

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[469] Aberle Direct at pp. 10-11.
[470] Aberle Rebuttal at p. 11.
[471] Heinen Direct at p. 48.
[472] *Id.*
[473] Ex. 212 at 48 (Heinen Direct).

F. Flexible Rate Proposal

1. Background on Great Plains' Services

372. Great Plains provides several types and combinations of natural gas service, including: sales; transportation; firm; interruptible; market rate; and standard service.[474]

373. Under sales service, Great Plains procures natural gas, reserves space on an interstate pipeline and arranges transportation of that gas on the pipeline and its distribution system to the customer's residence or business.[475]

374. Under transportation service, customers acquire their own gas supplies through an unregulated gas supplier and arrange for delivery of these shipments to a Town Border Station (TBS). At the TBS, Great Plains' distribution system is used to transport gas to the customer.[476]

375. Transportation-only service is not available to residential and small business customers. Instead, these customers must take sales service.[477]

376. Larger customers can choose between sales service and transportation service.[478]

377. Both sales and transportation customers may take either firm or interruptible service. Firm service is not subject to curtailment or interruption by Great Plains unless there is an emergency. This service is priced to include the added costs of assuring deliveries of gas supplies.[479]

378. By contrast, service to customers on interruptible tariffs can be curtailed as needed to maintain system reliability.[480]

379. A fundamental principle in designing transportation and sales rates is that they should keep Great Plains indifferent as to whether customers take transportation or sales service. In other words, customers should decide whether to use Great Plains' sales or transportation services primarily on a comparison between the costs of purchasing gas from Great Plains and the cost of purchasing gas from a third-party supplier.[481]

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474 Ex. 211 at 26 (Heinen Direct).
475 *Id.*
476 *Id.*
477 *Id.*
478 *Id.*
479 *Id.*
480 *Id.* at 26-27.
481 *Id.* at 29.

380. Regardless of where customers obtain gas supplies, all customers must pay Great Plains for use of its local distribution system, which includes TBSs, different sizes of underground pipes and associated equipment.[482]

381. This transportation component is regulated in Minnesota because the distribution of natural gas along such systems is considered to be a "natural monopoly."[483]

382. Rates for all of these services must include, at a minimum, the incremental cost of transporting natural gas through the distribution system, along with costs for metering, billing and other customer services.[484]

2. Limits of the "Natural Monopoly" in Gas Distribution

383. Once standard rates are approved by the Commission, Great Plains may not change those rates (except to reflect changes in the cost of gas) without an order, rider, or adjustment from the Commission.[485]

384. Great Plains charges residential customers a standard tariffed rate.[486]

385. Customers that have the capability to bypass Great Plains' distribution system, and meet their energy needs with fuel from other sources, are regarded as "subject to effective competition." These customers may be offered gas service at flexible rates, not available to other customers, so that Great Plains can maintain these accounts. Minn. Stat. § 216B.163, subd. 1(b) (2014), defines "effective competition" as:

> a customer of a gas utility who either receives interruptible service or whose daily requirement exceeds 50,000 cubic feet maintains or plans on acquiring the capability to switch to the same, equivalent or substitutable energy supplies or service, except indigenous biomass energy supplies composed of wood products, grain, biowaste, and cellulosic materials at comparable prices from a supplier not regulated by the commission.[487]

386. For example, if an interruptible service customer uses an alternative to gas (such as propane, coal, fuel oil) for price reasons, that customer is placed on a flexible rate and must remain on the rate for at least one year. Similarly, if a customer is able to obtain gas from suppliers that are not regulated by the

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482 Ex. 211 at 29 (Heinen Direct).
483 *Id.*
484 *Id.*
485 Minn. Stat. § 216B.16, subd. 7 (2014); Ex. 211 at 31 (Heinen Direct).
486 Ex. 211 at 31 (Heinen Direct).
487 Minn. Stat. § 216B.163, subd. 1(b) (2014).

Commission, that customer is "subject to effective competition," and may obtain flexible rates.[488]

387. Under flexible rates, Great Plains may vary the non-gas portion of the commodity rate for eligible customers within a specified range as approved by the Commission. The Commission is required to set a minimum rate (which must recover at least the incremental cost of providing the service) and a maximum rate.[489]

388. When setting flexible rates, the Commission has recognized that minimum rates for sales customers must at least recover the weighted average cost of gas and O&M costs.[490]

389. Minimum flexible rates for transportation customers recover only the O&M costs.[491]

390. The law also requires that a customer who takes service under a flexible tariff must remain on that tariff for some reasonable period of time.[492]

391. This flexibility allows Great Plains to remain competitive with alternatives to gas service from Great Plains.[493]

392. In each general rate case, the Commission revisits the question of whether the utility has demonstrated that particular customers receiving flexible rates remain eligible for those rates and that any proposed discounts are reasonable. The Commission undertakes this review because the approval of flexible rates necessarily obliges the shifting of costs that are not recovered (and the corresponding revenue requirements) on to standard rate customers.[494]

393. Great Plains proposes to extend negotiated "flex" rates (that are lower than the standard rate) to four large customers – three existing customers and one new customer.[495]

394. The DOC-DER disputes the reasonableness of providing flexible rates to two of these four customers – one existing customer, Customer A, and the new customer, Customer B. Both Customer A and Customer B are classified as "Large Interruptible Transportation-only" customers.[496]

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488 Minn. Stat. § 216B.163, subd. 1(b) (2014); Ex. 213 at 7-8 (Heinen Surrebuttal).
489 Minn. Stat. § 216B.163, subd. 4 (2014); Ex. 211 at 31-32 (Heinen Direct).
490 Ex. 211 at 32 (Heinen Direct).
491 *Id.*
492 Minn. Stat. § 216B.163, subd. 4 (2014); Ex. 211 at 32 (Heinen Direct).
493 *See* Minn. Stat. § 216B.163, subd. 4 (2014); *see also* Ex. 211 at 32 (Heinen Direct).
494 *See* Minn. Stat. § 216B.163, subds. 3, 5 (2014); *see also* Ex. 211 at 32-34, AJH-10 (Heinen Direct); Evidentiary Hearing Tr. at 84-86 (Aberle).
495 *Id.*
496 Ex. 213 at 11-13 (Heinen Surrebuttal); Ex. 222 at 1 (Heinen Testimony Summary).

3. Customer A

395. Great Plains maintains that Customer A, a large transportation-only customer, has the ability to bypass Great Plains' natural gas system.[497]

396. Customer A was a flexible service customer at the time Great Plains submitted its 2004 rate case.[498]

397. Great Plains has since negotiated terms of service with Customer A under a flexible rate arrangement. Great Plains acknowledges that under the terms it negotiated, Customer A's flexible rates will be higher than Great Plains' proposed standard fixed tariff rates for customers of the Large Interruptible Transportation class.[499]

398. Great Plains maintains that Customer A's costs of bypassing Great Plains' system could be recovered within 12 years, a circumstance that, in its view represents a significant risk of bypass.[500]

399. The DOC-DER disagrees with the Company that a 12-year payback period for recovery of bypass-related costs represents a significant risk that Customer A will depart the system.[501]

400. The Administrative Law Judge agrees with the DOC-DER that Customer A does not represent a significant risk of departure and is not otherwise subject to effective competition. Given that Customer A agreed to pay higher rates than the proposed standard fixed tariff rate for Large Interruptible Transportation customers, and faces a 12-year period before it would be able to recover the costs of migrating away from Great Plains' system, it seems quite reliant upon continued gas service from Great Plains. Great Plains did not demonstrate that extending a flexible rate to Customer A is appropriate.[502]

4. Customer B

401. Great Plains asserts that Customer B, another large transportation-only customer, has the ability to switch from natural gas to competitively-priced alternative fuels – specifically coal and fuel oil.[503]

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[497] Ex. 27 at 3-4 (Aberle Rebuttal); Ex. 212 at 34, TS AJH-10 at 1-3 (Heinen Direct).
[498] *See* Ex. 26 at 3-4 (Aberle Rebuttal).
[499] Ex. 26 at 4 (Aberle Rebuttal); Ex. 213 at 10 (Heinen Surrebuttal); *see also* Ex. 212, AJH-10 at 1-3 (Heinen Direct).
[500] Ex. 26 at 4 (Aberle Rebuttal); Ex. 213 at 10 (Heinen Surrebuttal); *see also* Ex. 212, AJH-10 at 1-3 (Heinen Direct).
[501] Ex. 26 at 4 (Aberle Rebuttal); Ex. 213 at 13 (Heinen Surrebuttal).
[502] Ex. 26 at 4 (Aberle Rebuttal); Ex. 213 at 10-13 (Heinen Surrebuttal); Ex. 222 at 1 (Heinen Testimony Summary); Evidentiary Hearing Tr. at 187-189 (Heinen).
[503] *See* Evidentiary Hearing Tr. at 74, 96 (Aberle).

402. Unlike Customer A, Customer B is a new customer and was not connected to Great Plains' distribution system during Great Plains' last rate case. Accordingly, discounts are not a matter that the Commission has addressed with respect to Great Plains' service to this customer.[504]

403. Great Plains argues that extension of flexible rates to Customer B is appropriate because Customer B: (1) furnished Contributions in Aid of Construction (CAIC) so as to connect its facility to Great Plains' distribution system; (2) faces significant competitive pressures to reduce its total energy costs; (3) is well-placed to receive efficient deliveries from Great Plains; and (4) would be a beneficial addition to Great Plains' base of natural gas customers.[505]

404. Great Plains acknowledges as well that the proposed set of discounted rates for Customer B would oblige corresponding subsidies from non-flex ratepayers.[506]

405. The hearing record does not establish that either of the alternative fuels – coal or fuel oil – were available to Customer B at quantities and prices that would subject Great Plains' services to significant price competition.[507]

406. Similarly, the hearing record does not establish that Customer B "plans on acquiring the capability to switch to" coal or fuel oil supplies, as those terms are used in Minn. Stat. § 216B.163, subd. 1(b).[508]

407. Customer B's provision of CAIC does not alter the analysis. Provision of these sums is a familiar practice and results in an "offset" of "the difference between the total revenue requirement of the project and the revenue generated from the customers served by the project."[509] It does not oblige, or prompt, a different rate structure from other similar customers.[510]

408. For these reasons, Great Plains' request for flexible rates for Customers A and B should be denied.[511]

409. The Administrative Law Judge concludes that the DOC-DER's proposed upward adjustment to test year revenues of $86,173 for both Customer A and Customer B is appropriate and supported by the record. The test year revenues for Customer A and Customer B should be based on the standard tariffed rate.[512]

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504 *See* Evidentiary Hearing Tr. at 203-04 (Heinen).
505 Ex. 26 at 4, 7 (Aberle Rebuttal); Evidentiary Hearing Tr. at 84-86 (Aberle).
506 Evidentiary Hearing Tr. at 85-86 (Aberle).
507 *Compare* Ex. 214 at 12-22 (Heinen Surrebuttal) *with* Evidentiary Hearing Tr. at 96-97 (Aberle).
508 *Compare* Ex. 213 at 22 (Heinen Surrebuttal) *with* Evidentiary Hearing Tr. at 96-97 (Aberle).
509 Minn. Stat. § 216B.1638, subd. 1(b) (2014).
510 *See generally id.*
511 *See* Ex. 213 at 9-22 (Heinen Surrebuttal).
512 *See* Ex. 211 at 34-35 (Heinen Direct); Ex. 213 at 7-8 and 22 (Heinen Surrebuttal); DOC Ex. 214, AJH-S-1 at 16-17 (Heinen Surrebuttal).

G. Consolidation of Purchased Gas Adjustment (PGA) Districts

410. When MDU purchased Great Plains in 2000, it inherited a long-term gas supply contract that required Great Plains to purchase its gas from the Emerson supply point at the interconnect between TransCanada Pipeline and Viking Gas Transmission (Viking). When the contract expired on October 31, 2012, Great Plains replaced the firm transportation capacity on TransCanada with firm capacity on the Northern Natural Gas (NNG) system.[513]

411. Great Plains' system is divided into a North PGA District and a South PGA District and each district currently has separate gas cost rates.[514]

412. For final rates in this case, Great Plains requests the Commission's approval to combine its North and South Districts and establish a single PGA District.[515]

413. Great Plains previously consisted of three PGA Districts (North 4, Crookston, and South). In Great Plains' 2004 rate case, the Commission approved Great Plains' request to consolidate its three PGA Districts into what is the North (formerly, North 4 and Crookston) and South Districts.[516] This rate case is the first time Great Plains has requested consolidation of the North and South PGA districts.[517]

414. Great Plains currently charges different rates for the natural gas it delivers to its North and South District customers.[518] There are approximately 12,000 customers in each district.[519] The different charges are a product of Great Plains' history of service under different contracts with different suppliers.[520]

415. Prior to October 2012, customers on the North District were served solely with gas procured under contract through the Emerson supply point in Manitoba (i.e., Canadian sourced gas) and, historically, customers on the South District were supplied with gas through the NNG pipeline system (i.e., Mid-Continent sourced gas).[521] Beginning in November 2012, and continuing to the present, all Great Plains customers have been served with natural gas supplied through the NNG system.[522]

416. Great Plains stated that the consolidation of the two PGA districts is reasonable because the two districts are essentially served by the same cost of gas

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[513] Ex. 24 at 3 (Morman Direct).
[514] COMMISSION STAFF BRIEFING PAPERS (Nov. 5, 2015) (eDocket No. 201511-115476-01).
[515] *Id.*
[516] Ex. 211 at 6 (Heinen Direct).
[517] *Id.*
[518] Ex. 24 at 2-3 (Morman Direct).
[519] *Id.*
[520] *Id.*
[521] Ex. 211 at 3 (Heinen Direct)
[522] *Id.*

using supply priced off NNG (at the same supply points), and the combination will result in efficiencies that will benefit customers.[523]

417. Mr. Robert Morman, Director of Gas Supply for MDU and Great Plains, gave four reasons in support of Great Plains' proposed consolidation of the two PGA districts:

1) More effective and efficient use of transportation capacity currently under contract (at times, the North has had under-used capacity while the South has exceeded its contracted capacity limits);

2) Better use of storage assets that currently are used only for the South District. This allow Great Plains to better manage imbalances and potential charges due to unexpected swings in weather;

3) Better use of current gas contracts to serve the North and South Districts. Consolidation provides the potential to purchase gas from points where it is less expensive for immediate use or storage; and

4) Great Plains could more effectively manage the combined North and South District's reserve margin to maintain an acceptable reserve margin for both districts though their combination.[524]

418. In summary, the combination of gas supply from two districts into a single gas supply jurisdiction makes sense as the two areas are served from the same pipeline (NNG) and have basically the same cost of gas supply thereby resulting in efficiencies that will benefit customers.[525]

419. The DOC-DER public utilities rates analyst, Mr. Adam Heinen, relied on the same three-part analysis used by the DOC-DER in the 2010 MERC general rate case, Docket No. G007,011/GR-10-977, to assess the reasonableness of Great Plains' proposal:

1) The proposed consolidation should be an integrated system and the physical flow, or transfer, of natural gas should be possible across the entire consolidated pipelines system;

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[523] Ex. 24 at 6 (Morman Direct).
[524] Ex. 24 at 5 (Morman Direct).
[525] *Id.* at 6.

2) Great Plains must show that changes in the conditions of service are sufficiently gradual to avoid drastic rate changes (rate shock) to customers; and

3) Great Plains must show that there will not be inter-pipeline or inter-regional subsidy as a result of consolidation.[526]

420. The DOC-DER also assessed likely rate impacts related to the proposed consolidation.[527] The DOC-DER confirmed that Great Plains satisfies factors 1 and 3 above: it has the ability to flow gas between the two districts on an integrated basis, and there is no meaningful difference in the weighted average cost of gas (WACOG) between the two PGA Districts.[528]

421. Regarding Factor 2, Mr. Heinen isolated the effects of PGA consolidation from changes in non-gas margins, and then assessed whether the changes in rates due to the PGA consolidation would be significant by examining the percentage change in rates related solely to the PGA consolidation.[529]

422. He concluded that, although the rate impact to South District customers likely to result from Great Plains' proposal "represent a significant rate impact on a monthly basis," the proposed changes likely would not constitute rate shock for South District ratepayers.[530] The average customer in the South District would see an increase of $6.89 per year while the average person in the North District would see a decrease of $8.76 per year.[531] On an average monthly basis, South District customers would see an increase of less than $0.60, while North District customers would see a decrease of $0.73. These impacts would be less than the rate impacts approved by the Commission in MERC's PGA consolidation in Docket No. G007,011/GR-10-977, with no phase-in.[532]

423. DOC-DER concluded from Mr. Heinen's analysis that Great Plains' proposed consolidation of its North and South PGA Districts is reasonable, as modified to begin on July 1, 2017.[533]

424. In addition, Mr. Heinen concluded that the small annual rate impact to South District customers likely would not constitute rate shock, as these impacts are less than the rate impacts approved by the Commission in MERC's PGA consolidation in Docket No. G007,011/GR-10-977, with no phase-in.[534]

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526 Ex. 211 at 6-7 (Heinen Direct).
527 *Id.*
528 *Id.* at 7-8.
529 *Id.* at 9-11.
530 *Id.*
531 *Id* at 13.
532 Ex. 211 at 16, AJH-4 (Heinen Direct).
533 Ex. 211 at 16-17 (Heinen Direct); Ex. 213 at 5-6 (Heinen Surrebuttal).
534 Ex. 211 at 16, AJH-4 (Heinen Direct).

425. The DOC-DER agreed that Great Plains' proposed consolidation of its North and South PGA Districts' supply portfolio is reasonable, as modified by DOC-DER's recommendation to mitigate rate impacts for the South District (and agreed upon by Great Plains), that the PGA consolidation would occur on the first July 1st following the implementation of final rates in this proceeding, which likely would be July 1, 2017.[535]

426. Essentially, because the costs of supplying gas are now the same or very similar for North and South District ratepayers, there no longer is a reasonable basis for charging customers in the North District higher costs than is charged to South District customers.[536]

427. The Administrative Law Judge agrees that the record supports Great Plains' requested consolidation of its North and South PGA Districts.

H. Consolidation of North and South Rate Areas

428. The same geographical areas that are currently divided into a North District and a South District for gas rates, as discussed above, are divided for the assessment of distribution rates.[537]

429. In its Petition, Great Plains proposes to consolidate its North and South Districts into a single rate area on the basis that the cost to serve the two distinct rate areas is similar and the consolidation of rates is appropriate at this time.[538]

430. In Great Plains' 2002 rate case (Docket No. G004/GR-02-1682), the Commission approved consolidation of the North 4 and Crookston rate areas (now the North District), which was completed in two phases over a three year period. The Commission consolidated two of Great Plains' three rate areas and approved, by rate class, consistent Basic Service Charges between the then-resulting North and South rate areas.[539]

431. The Commission maintained different volumetric non-gas margins between the two rate areas, and in Great Plains' 2002 rate case, the Commission continued to maintain different volumetric non-gas margins between the two rate areas.[540]

432. There are no identifiable differences in serving the two rate areas.[541]

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535 Ex. 213 at 5 (Heinen Surrebuttal); Ex. 22 at 2 (Jacobson Rebuttal).
536 *See* Evidentiary Hearing Tr. at 199-200 (Heinen).
537 *See generally*, Ex. 25 at 9 (Aberle Direct).
538 Ex. 25 at 9 (Aberle Direct).
539 Ex. 211 at 18 (Heinen Direct).
540 *Id.*
541 Evidentiary Hearing Tr. at 90 (Aberle).

433. Great Plains notes that, with gas commodity costs at a relatively low level, consolidation of the rate areas in this rate case may have less of an effect on customers than would be the case during a time of high gas costs.[542]

434. The DOC-DER concluded that consolidation is reasonable given that Great Plains has been operating the two areas as part of the same system, with the same set of employees, equipment, office supplies, cost of capital, and combined sales.[543] These are the components that make up the non-gas costs that are recovered in the non-gas margins.[544] Thus, there are no identifiable differences in serving the two rate areas.[545]

435. The OAG and DOC-DER expressed concern regarding the rate impact on South District customers, with the DOC-DER suggesting a phase-in of the consolidation and OAG initially recommending that Great Plains consider mitigating the impacts in some manner.[546]

436. In addition to the rate impact of the rate area consolidation, Mr. Heinen identified multiple increases that ratepayers may experience due to consolidation of the PGA areas (particularly the South PGA area), together with the general rate increase proposed for all customers that is the subject of this rate case.[547]

437. The DOC-DER recommended a two-stage phase-in, over three years similar to the mechanism agreed to by Great Plains in its 2002 rate case, and presented in the *Joint Supplemental Comments* filed by Great Plains and the DOC-DER in that matter, a copy of which is appended to Mr. Heinen's Direct Testimony as AJH-8.[548]

438. Great Plains agreed with implementing the consolidation in two stages, but supports a two-year and not a three-year period.[549]

439. Great Plains acknowledged that the proposed rate increase together with rate consolidation, for large interruptible customers, would result in customers in the North paying about $295,000 while customers in the South Distrcit would pay an additional $1.3 million.[550]

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542 *Id.*
543 Ex. 211 at 19 (Heinen Direct).
544 *Id.*
545 Evidentiary Hearing Tr. at 89 (Aberle).
546 Ex. 102 at 11 (Lindell Surrebuttal); Ex. 211 at 21-22 (Heinen Direct).
547 Ex. 213 at 24-25 (Heinen Surrebuttal); Evidentiary Hearing Tr. at 197-198 (Heinen).
548 Ex. 211 at 22, AJH-8 (Heinen Direct).
549 Ex. 27 at 15 (Aberle Rebuttal).
550 Evidentiary Hearing Tr. at 90 (Aberle).

440. Great Plains considered a three-year phase-in to unnecessarily prolong the benefits of consolidating the North and South rate areas which, when analyzed alone, would have minimal rate increases for each of phase-in periods.[551]

441. Great Plains provided detailed exhibits showing the rate impacts associated with a rate phase-in similar to what was approved by the Commission in the 2002 rate case, and a discussion explaining how each phase would be implemented.[552]

GREAT PLAINS NATURAL GAS CO.
GAS UTILITY – MINNESOTA
Bill Comparisons – Overview
South Area

Customer Class	Average Monthly Usage in Dkt	Average Monthly Bill Old Rates*	Phase 1 Monthly Bill **New Rates***	Phase 2 Monthly Bill **New Rates***	Phase 3 Monthly Bill **New Rates***
Residential	6	$41.22	$44.96	$45.72	$46.49
Small Firm General Service	11	80.93	88.87	89.65	90.44
Large Firm General Service	79	462.59	492.62	498.26	503.91
Interruptible Sales Service–Small Volume	434	1,970.67	1,996.15	1,998.50	2,000.84
Interruptible Sales Service–Large Volume	4,770	17,301.40	17,053.40	17,455.39	17,857.50
Interruptible Transportation Small Volume	585	783.63	788.39	791.55	794.71
Interruptible Transportation Large Volume	13,050	5,116.35	5338.20	6,438.31	7,538.43

442. The rate impacts, based on Great Plains' initial filing and revenue apportionment, as shown in Ms. Aberle's Rebuttal Testimony, appear reasonable and are comparable to the phase-in calculations in Great Plains' 2002 rate case.[553]

443. These rate impacts assume for purposes of calculation Great Plains' revenue deficiency or apportionment of revenue and, thus, will be affected by adjustments approved by the Commission.[554]

[551] Ex. 213 at 23 (Heinen Surrebuttal).
[552] Ex. 26 at 15-18, TAA-7 (Aberle Rebuttal).
[553] Ex. 26 at 26 (Aberle Rebuttal); Ex. 211, AJH-8 (Heinen Direct); *see also* Ex. 25, TAA-7 (Aberle Direct).
[554] Ex. 213 at 26 (Heinen Surrebuttal).

444. Great Plains' schedule for implementing the consolidation appears sound because gas rates are currently relatively low and because the increase in customers' bills does not appear to approach increases that would constitute rate shock. It is worth noting that although given notice of the potential rate increases and an opportunity to comment, no rate payer in the Southern District and very few in the Northern District commented on the overall proposed rate increases.

445. The Administrative Law Judge recommends approval of Great Plains' proposed two-stage consolidation over a two-year phase-in.

XIV. TARIFF ISSUES

A. Introduction

446. Every public utility must file with the Commission schedules showing all rates, tolls, tariffs, and charges which is has established and which are in force at the time of any service performed by it within the state, or for any service in connection therewith or performed by any public utility controlled or operated by it.[555]

447. Tariffs, determined as a part of rate design, are the Commission-approved written statements of a utility's rates and terms and conditions of service. From a financial perspective, tariffs are structured to ensure that the utility has a reasonable opportunity to recover the test year revenue requirement approved by the Commission as part of a general rate case and must result in just and reasonable rates.

B. Tariff Issues, Undisputed

1. PGA Recovery Threshold:

448. This issue is resolved between the DOC-DER and Great Plains.

449. Great Plains proposed to modify the threshold for changing rates under the PGA mechanism from a change that exceeds $0.03 per Dkt from the prior month to a change that exceeds $0.25 per Dkt from the prior month.[556]

450. Great Plains argued that the proposal would result in fewer filings and, overall, there would be no impact to ratepayers because any amount below the threshold would be rolled into the annual true-up adjustment and ultimately recovered, or returned, to ratepayers.[557]

451. The DOC-DER objected to the proposal, arguing that Great Plains' proposal is inconsistent with Minn. R. 7825.2700, subp. 3 (2015), that the information

[555] Minn. Stat. § 216B.05, subd.1 (2014).
[556] Ex. 213 at 30 (Heinen Surrebuttal); *see* Ex. 25 at 15 (Aberle Direct) (Great Plains later corrected its stated threshold amount as $0.03 per Dkt).
[557] Ex. 25 at 15 (Aberle Direct).

provided by Great Plains in support of the change was not compelling and there is no appreciable benefit to ratepayers.[558]

452. Consistent with the recommendation of Mr. Heinen, Great Plains will request a variance from the requirements of Minnesota Rule 7825.2700, subp. 3, instead and file the proposal in a separate docket.[559]

453. The Administrative Law Judge agrees that withdrawal of this issue by Great Plains is reasonable.

2. Demand Charges to Interruptible Customers:

454. Great Plains proposes to charge interruptible customers a demand component based on a 100 percent load factor allocation of Great Plains' system demand charges. The load factor is proposed to be assessed as a per unit cost of demand for interruptible customers and any amounts received from interruptible customers would be credited to firm customers through the annual automatic adjustment mechanism.[560]

455. Great Plains provided an illustrative example of how its load factor allocation will work.[561]

456. Great Plains explained that the amount of demand costs collected from interruptible customers on an actual basis will offset the future rates paid by firm customers and will be credited to firm customers through the Annual Automatic Adjustment filing.[562]

457. Great Plains' reason for the proposal is that interruptible customers utilize and benefit from capacity on the pipeline throughout the year and should bear a portion of the costs of acquiring that capacity.[563]

458. Great Plains further stated that Great Plains will not procure additional capacity under this proposal nor will existing contracted capacity be assigned to interruptible customers.[564]

459. The DOC-DER agreed that Great Plains showed the reasonableness of this proposal and concluded that it would not impact firm customers.[565]

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[558] Ex. 212 at 62 (Heinen Direct).
[559] Ex. 26 at 21 (Aberle Rebuttal).
[560] Ex. 19 at 21 (Jacobson Direct).
[561] Ex. 22, TRJ-6 (Jacobson Rebuttal).
[562] *Id.*
[563] Ex. 19 at 21-22 (Jacobson Direct).
[564] Ex. 22 at 2-3 (Jacobsom Rebuttal).
[565] Ex. 213 at 5-6 (Heinen Surrebuttal).

460. No party opposes Great Plains' proposal and the Administrative Law Judge agrees that it is reasonable.

3. Return Check Charge

461. This issue is resolved between the DOC-DER and Great Plains.

462. Great Plains' current returned check charge is $12.[566]

463. Great Plains initially proposed a return charge of $30. This amount was not established on a direct cost basis. Rather, Great Plains sought to establish a charge sufficient to act as a deterrent to customers issuing insufficient checks because returned checks cause Great Plains additional administrative expenses.[567]

464. Great Plains reviewed the work process including employee wage and allotted time, estimated at 35 minutes, needed to handle the reversal of the payment and found that based on the current payroll charge costs would equate to approximately $18.25.[568]

465. In addition to processing time, on occasion additional postage expense, long distance charges and bank charges are also incurred.[569]

466. The DOC-DER agreed that Great Plains has shown that the current fee of $12 does not cover the costs of processing returned checks. The DOC-DER did not agree that Great Plains showed that the proposed fee of $30 was reasonable.[570]

467. The DOC-DER recommended a Returned Check Charge of $18.25, which represents the cost of processing checks by Great Plains, and results in an increase to test year revenue of $962.[571]

468. Great Plains agreed to the DOC-DER's proposed returned check charge.[572]

469. The Administrative Law Judge agrees that the proposed charge of $18.25, based on actual labor costs, is reasonable.

470. If the Commission allows the proposed fee of $18.25, test year revenues should be increased by approximately $962.[573]

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[566] Ex. 25 at 16 (Aberle Direct).
[567] Ex. 211 at 83-84 (Heinen Direct).
[568] *Id.*
[569] *Id.*
[570] *Id.*
[571] *Id.*
[572] Ex. 26 at 23 (Aberle Rebuttal); Ex. 213 at 46 (Heinen Surrebuttal).
[573] Ex. 211 at 85 (Heinen Direct).

4. Reconnection Fee Calculation for Seasonal Customers

471. This issue is resolved between the DOC-DER and Great Plains.

472. Great Plains proposed to charge the Basic Service Charge for the days out of service for customers that disconnect service on a seasonal basis as provided in the Reconnection of Service provision Section V. par. 22.[574]

473. This recognizes the fixed costs associated with serving customers and the fact that costs are not avoided when a customer disconnects service on a seasonal basis.[575]

474. Great Plains also proposed to recognize the distribution margin collected from the non-residential seasonal customer in determining the seasonal reconnect charge.[576]

475. The DOC-DER recommended approval of Great Plains' proposed changes in its Reconnection Fee calculation for seasonal customers.[577]

476. The DOC-DER recommended that, if this tariff change is approved, a change in the calculation of the reconnection fee for seasonal customers, will result in an increase of $3,018 in test year revenue.[578]

477. In its Issues Matrix, Great Plains stated that it did not dispute the amount of increase to test year revenue.[579]

478. The Administrative Law Judge agrees that Great Plains' proposal is reasonable and recommends it approval together with the associated increase of $3,018 in test year revenue.

5. Service and Main Extensions Resolved between DOC and Great Plains

479. This issue is resolved between the DOC-DER and Great Plains.

480. The DOC-DER confirmed through its review that Great Plains appears to have correctly administered its service and main extension tariffs.[580]

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[574] Ex. 25 at 16 (Aberle Direct); Ex. 211 at 85 (Heinen Direct).
[575] *Id.*
[576] *Id.*
[577] Ex. 222 (Heinen Testimony Summary).
[578] Ex. 213 at 35-38 (Heinen Surrebuttal).
[579] ISSUES MATRIX at 21-22 (Apr. 22, 2016).
[580] Ex. 211 at 105 (Heinen Direct); Ex. 213 at 42 (Heinen Surrebuttal).

6. Assessing Demand Charges to Interruptible Customers

481. Mr. Heinen agreed that Great Plains' proposal to charge interruptible customers a demand component based on a 100 percent load factor allocation of Great Plains' system demand charges is reasonable.[581]

482. The rationale for this change is that interruptible customers, when they are not interrupted, derive benefit from demand costs or guaranteed capacity that is meant to serve firm customers.[582]

483. The Administrative Law Judge agrees that Great Plains' proposal is reasonable and recommends it approval.

7. Other Tariff Charges Resolved between DOC and Great Plains

484. The DOC-DER recommended approval of Great Plains' proposed tariff changes listed on pages 14 to 16 of Ms. Aberle's Direct Testimony; and rejection of any proposed tariff change that was not specifically identified.[583]

XV. TARIFF ISSUES, DISPUTED

A. Revenue Decoupling Mechanism (RDM)

1. Introduction

485. Decoupling is a regulatory tool designed to separate a utility's revenue from changes in energy sales.[584] The purpose of decoupling is to reduce a utility's disincentive to promote energy efficiency.[585]

486. Revenue decoupling criteria and standards are designed to mitigate the impact on public utilities of the energy savings goals found in Minn. Stat. § 216B.241 (2014) without adversely affecting utility ratepayers.[586]

487. Ordinarily, utility revenues increase as sales increase; traditionally regulated utilities therefore have an incentive to promote (or not diminish) incremental sales of natural gas.[587]

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[581] Ex. 211 at 63 (Heinen Direct).
[582] Evidentiary Hearing Tr. at 208 (Heinen); Ex. 19 at 21-22 (Jacobsen Direct).
[583] Ex. 211 at 59 (Heinen Surrebuttal).
[584] Minn. Stat. § 216B.2412, subd. 1.
[585] *Id.*
[586] Minn. Stat. § 216B.241.
[587] *In re Application by CenterPoint Energy Res. Corp. d/b/a CenterPoint Energy Minn. Gas for Auth. to Increase Natural* Gas *Rates in Minn.*, PUC Docket No. G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 43-44 (June 9, 2014).

2. Great Plains' Initial Plan

488. Great Plains does not currently have a revenue decoupling plan. Great Plains has proposed an RDM that it believes meets the requirements of Minn. Stat. § 216B.2412 (2014). Great Plains asserts its RDM will reduce Great Plains' financial disincentive to promote energy efficiency and conservation by separating the link between Great Plains revenues from changes in the volume of gas sales.[588]

489. Great Plains' RDM, as initially proposed, included eight components:

- The proposal would be a full decoupling mechanism that includes all changes in sales in the applicable rate classes;
- The proposal would be assessed to all rate classes and customers, except for one CIP-exempt customer in the Large Volume Interruptible Transportation rate class;
- Rate adjustments would be made annually, on a class-by-class basis;
- There would be no cap on the increases in revenue adjustments because the non-CIP delivery charge only makes up approximately 20 percent of applicable bills and thus Great Plains asserted that it is highly unlikely that any rate increase would create rate shock;
- Rate adjustments would be applied to the delivery charge and applied on a volumetric basis;
- The rate adjustment would be displayed as a separate line item on the customer's bill;
- The revenue decoupling mechanism is proposed as a pilot program and would last for 36 months. The initial evaluation period for determining the revenue adjustments would begin the first day of the month following the Commission's order;
- Great Plains would provide an evaluation report to the Commission each year of the pilot program. The evaluation report will contain information and data similar to what is provided to the Commission in other decoupling reports from other utilities.[589]

[588] Ex. 25 at 23 (Aberle Direct).
[589] Ex. 211 at 75-76 (Heinen Direct).

3. The Positions of the Parties

490. The proposed RDM issue is partially disputed between the DOC-DER and Great Plains. The OAG did not take a position on the RDM.

491. The DOC-DER proposes an asymmetrical cap on revenues with no limit on potential refunds and a 10 percent cap on surcharges based on non-gas margin revenues, not including Conservation Cost Recovery Charge revenues.[590]

a. Flexible Rate Customers

492. Great Plains originally proposed to apply the RDM to all customers except one flexible rate customer.[591]

493. The DOC-DER noted two concerns regarding the application of Great Plains' proposed RDM to flexible rate customers. The first potential issue is that rates for flexible rate customers could end up outside the Commission approved rate bands depending on the size of the adjustment applied.[592] The second potential issue would be flexible rates falling below the incremental cost of service and thus violating Minnesota law.[593]

494. While Great Plains reasoned that the symmetrical 10 percent cap it proposes eliminates the potential for either scenario to occur, upon further review it modified its original request. Great Plains proposes now to exclude all flexible rate customers from the RDM.[594]

495. Great Plains decided that given the limited number of flexible rate customers associated with this group, it is unnecessary to include the complexities of applying the RDM to the class under this pilot program.[595]

496. DOC-DER agreed with Great Plains' recommendation that the adjustment should not be assessed to flexible rate customers.[596]

497. The Administrative Law Judge agrees that the exclusion of flexible rate customers from Great Plains' decoupling proposal is reasonable in order to avoid the potential issues raised by the DOC-DER.

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[590] Ex. 25 at 23-29 (Aberle Direct); Ex.214 at 37 (Heinen Surrebuttal).
[591] Ex. 25 at 23-29 (Aberle Direct).
[592] Ex. 27 at 26 (Aberle Rebuttal).
[593] *Id.*
[594] *Id.*
[595] *Id.*
[596] Ex. 211 at 78-81(Heinen Direct); Ex. 213 at 40 (Heinen Surrebuttal).

b. Asymmetrical or Symmetrical Cap

498. Great Plains originally proposed a RDM without a cap. Great Plains subsequently proposed a symmetrical cap on the revenue adjustment of 10 percent of non-gas margin revenue for both potential surcharges and refunds to customers. Great Plains proposes the 10 percent cap be calculated and applied individually for each rate class due to the fact that a common sales volume decrease will impact each rate class differently in terms of evaluation of whether the threshold of the cap has been met.[597]

499. As noted above, Great Plains' original proposal had no cap on increases in revenue adjustments. Great Plains now argues that because the non-CIP delivery charge only makes up approximately 20 percent of the applicable customer's typical bill, any RDM adjustment is unlikely to adversely affect customers in a material way when capped at 10 percent.[598]

500. The DOC-DER's position is that unless modified Great Plains' decoupling proposal has the potential to adversely ratepayers.[599] Specifically, the DOC-DER stated that, as originally proposed without a cap, rate payers would be exposed to all the risks of decoupling.[600]

501. Great Plains agreed with the DOC-DER that a properly designed cap can be implemented that will both limit the potential impact of an RDM adjustment on the customer as well as keep intact the benefits of the RDM to Great Plains.[601]

502. In response to the DOC-DER's concerns about the potential adverse impacts of an RDM adjustment on customers if a cap is not implemented,[602] Great Plains proposed the above mentioned symmetrical cap of 10 percent of non-gas margin revenue for both potential surcharges and refunds to customers.[603] Under Great Plains' proposal there would be: a 10 percent cap on its ability to surcharge ratepayers as well as a 10 percent cap on its refunds to ratepayers.[604]

503. Great Plains proposed the 10 percent cap to be calculated and applied individually for each rate class on the basis that a common sales volume decrease will impact each rate class differently in terms of evaluating whether the threshold of the cap has been met.[605]

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[597] Ex. 27 at 26 (Aberle Rebuttal).
[598] *Id.* at 25.
[599] Ex. 212 at 78-79 (Heinen Direct).
[600] *Id.* at 79.
[601] Ex. 27 at 25 (Aberle Rebuttal).
[602] Ex. 212 at 79-80 (Heinen Direct).
[603] Ex. 27 at 25 (Aberle Rebuttal).
[604] Evidentiary Hearing Tr. at 72 (Aberle); Ex. 27 at 25 (Aberle Direct).
[605] Ex. 27 at 25 (Aberle Rebuttal).

504. The DOC-DER recommends that the Commission modify Great Plains' proposal to include a revenue cap similar to what was approved in the 2013 CenterPoint Energy case. Specifically, the DOC-DER recommends an asymmetric cap on the revenue adjustment with no cap on potential refunds to taxpayers and a cap of 10 percent of non-gas margin revenue, not including Conservation Cost Recovery Charge (CCRC) revenues, on potential surcharges to customers.[606]

505. Under the DOC-DER's proposal, there is no limit on the amount of refunds Great Plains must pay customers in the event of its over-recovery in the event, for example, of colder-than-normal weather, but with a limit (10 percent of non-gas margin revenue, not including CCRC revenue) on the amount that ratepayers may be surcharged by Great Plains due to under-recovery caused by warmer-than-normal weather.[607]

506. The Commission has approved three gas decoupling mechanisms. With each approved RDM, it has required a cap on the utility's ability to surcharge. In two of the three cases (CenterPoint's 2008 and 2013 rate case orders) it required no cap on refunds to ratepayers.[608]

507. Consistent with the Commission's three RDM rate case orders for CenterPoint and MERC, the DOC-DER recommended a cap on the amount that Great Plains may surcharge ratepayers. Consistent with the Commission's recent CenterPoint rate case orders, the DOC-DER also recommended that the level of the cap be set at 10 percent of non-gas margin revenue, not including CCRC revenues.[609]

508. Not capping the amount of refunds is consistent with the Commission's recent CenterPoint 2103 rate case decision, and DOC-DER argues that unlimited refunds would assist ratepayers in mitigating the potential impact of surcharges (even though capped at 10 percent).[610] DOC-DER believes that a cap on refunds would place

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[606] Ex. 212 at 83 (Heinen Direct).
[607] Ex. 213 at 38-40 (Heinen Surrebuttal).
[608] Ex. 211 at 74-75 (Heinen Direct). The Commission's RDM details are set forth in the following three orders: *In re Application by CenterPoint Energy for Authority to Increase Natural Ga Rates in Minnesota,* Docket No. G-008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 23 (January 11, 2010) (partial decoupling pilot program; asymmetrical cap with no limit on refunds to ratepayers but 3 percent utility limit on surcharges); *In re Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-007, 011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 13-14 (July 13, 2012) (full decoupling pilot with symmetrical 10 percent cap on refunds and surcharges); and *In 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. G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 46-48 (June 9, 2014) (full decoupling pilot with an asymmetric cap limiting utility surcharges to 10 percent (no stated limit on refunds)).
[609] Ex. 222 at 6 (Heinen Testimony Summary).
[610] Ex. 213 at 38 (Heinen Surrebuttal).

a greater burden on ratepayers than on Great Plains because Great Plains has the option of seeking rate relief in form of a rate case.[611]

509. Based on the rationale and recommendations of the DOC-DER, the Administrative Law Judge agrees that a cap on refunds to ratepayers in the event of extreme increases in usage may adversely impact ratepayers.

510. The Administrative Law Judge recommends approval of Great Plains' proposed RDM, as modified by the DOC-DER's recommendation to require both the agreed-upon 10 percent cap on surcharges and that no cap be imposed on the amount of refunds that Great Plains might owe to ratepayers.

c. Evaluation Plan

511. The DOC-DER agreed that Great Plains' annual evaluation plan for its pilot full decoupling mechanism met the requirements ordered by the Commission in the Docket E. G999/CI-08-132.[612]

512. The DOC-DER did not believe that Great Plains' Plan was clear about how the Company will evaluate whether the proposed full decoupling mechanism had a positive impact on Great Plains' achievement of energy saving and, if so, to what extent.[613]

513. The DOC-DER recommended that Great Plains establish in greater detail what its baseline of comparison would be, what metrics it would use to determine whether Great Plains' revenue decoupling adjustment influenced higher energy savings and, if savings occurred, to what extent.[614]

514. Great Plains responded to the DOC-DER's concerns by agreeing to submit an evaluation report to the Commission each year of the pilot period and agreed to work with the parties in determining the appropriate reporting requirements.[615]

515. This issue is resolved between the DOC-DER and Great Plains.

B. Eliminate Standby Charge Tariff

516. This issue is disputed between the DOC-DER and Great Plains.

517. Great Plains has Standby Service rates approved for Great Plains' firm customers to address situations where customers were utilizing natural gas service as a standby energy source, causing increased peak demand without the typical annual

[611] *Id.*
[612] Ex. 211 at 77 (Heinen Direct).
[613] *Id.* at 78.
[614] *Id.*
[615] Evidentiary Hearing Tr. at 72 (Aberle).

consumption associated with a heating customer.[616] Standby Service rates were initially approved for Great Plains as part of its 2002 rate case.[617]

518. The standby charges were designed to recover the fixed customer and demand related costs not recovered through the Basic Service Charge.[618]

519. Great Plains determined that the application of the standby charge is difficult to administer because customers' consumption patterns do not always clearly indicate the presence of a standby source of energy. Therefore Great Plains proposes to eliminate this charge as no longer necessary because of the proposed increase in the Basic Service Charge rate component and the proposed Revenue Decoupling Mechanism.[619]

520. The DOC-DER recommended rejection of Great Plains' proposal to eliminate its Standby Charge tariff due to a lack of showing that it would be reasonable and because elimination would negatively impact other customers in these rate classes who become responsible for the unrecovered demand and customer costs associated with the Standby Charge customers.[620]

521. The DOC-DER recommended rejection of Great Plains' proposal to eliminate its Standby Charge tariff because doing so would harm other customers by requiring other firm class members to pay the unrecovered customer-related and demand-related costs that current standby customers pay.

522. Great Plains disagreed and continued to propose elimination on the grounds that it is difficult to administer due to the fact that customers' consumption patterns do not always clearly indicate the presence of a standby source of energy.[621]

523. Great Plains explained that applying the Standby tariff is difficult due to its inability to confirm if a customer is in fact only using natural gas for standby purposes. That lack of confirmation results in a subjective application of the Standby Charge that Great Plains seeks to avoid by eliminating the Standby Charge at this time.[622]

524. Great Plains believed that its proposed increase in the Customer Charge as well as its Revenue Decoupling mechanism would mitigate the need to retain the Standby tariff.[623]

525. Notwithstanding Great Plains' concerns, the DOC-DER's witness, Mr. Heinen, concluded that the potential harm to other customers outweighed the

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[616] Ex. 25 at 12-13 (Aberle Direct).
[617] Ex. 211 at 64 (Heinen Direct).
[618] Ex. 25 at 13 (Aberle Direct).
[619] Ex. 25 at 13 (Aberle Direct).
[620] Ex. 211 at 64-68 (Heinen Direct); Ex. 213 at 32 (Heinen Surrebuttal).
[621] Ex. 25 at 13 (Aberle Direct).
[622] Ex. 26 at 22 (Aberle Rebuttal).
[623] Ex. 211 at 64-65 (Heinen Direct).

reasons for discontinuing this tariff. Mr. Heinen explained that the following reasons for elimination provided by Great Plains do not justify eliminating the Standby tariff:

1) First, in terms of high costs, Great Plains provides no discussion, or data, in this record showing the costs required to administer the tariff.

2) The revenue recovered from the Standby tariff is not insignificant and there is no evidence that administrative costs are greater than, or near to, the revenue recovered from this tariff; and

3) In terms of zero usage and greater usage by Standby customers in the heating season months, these occurrences are not unexpected. It is conceivable that zero usage could occur for any number of reasons (e.g., vacation, faulty meter) and may not be related to the type of service received by the customers. Greater use by standby customers compared to regular customer is also not compelling because standby customers theoretically should only use gas in peak or higher consumption periods. The possibility exists that when they do use gas it is in a more intensive manner or their natural gas appliances or building conditions may not be as efficient as standard customers.[624]

526. The DOC-DER acknowledged that if Great Plains could show that there was systemic abuse of this service, then discontinuance would be appropriate, but the record in this case does not make such a demonstration, and it is clear that other customers likely would be harmed by higher costs if the Standby tariff were eliminated.[625] Mr. Heinen analyzed the likelihood that Great Plains' proposed Basic Service Charge increase and its Revenue Decoupling Mechanism would make up for the revenue lost by elimination of the Standby tariff, and concluded that they likely would not.[626]

527. The Administrative Law Judge agrees that Great Plains did not show that elimination of the Standby tariff is reasonable, and the DOC-DER demonstrated that maintaining the tariff will benefit other firm ratepayers and therefore recommends rejection of Great Plains' proposed elimination of the Standby tariff at this time.

C. First-Through-The-Meter Proposal for Interruptible Classes

528. This issue is disputed between the DOC-DER and Great Plains.

[624] *Id.* at 66-67.
[625] *Id.* at 65-68.
[626] *Id*. at 67-68.

529. Great Plains' proposal would allow an interruptible customer to have a certain level of firm service, but without having to add a meter or a service line.[627] Great Plains' witness, Ms. Aberle, explained that Great Plains would consider the first gas through the meter as charged under firm rates up to the level for which the customer had contracted, with additional volumes charged at the interruptible rate and subject to interruption.[628]

530. The purpose of the proposal is to avoid unnecessarily adding another meter and service line.[629]

531. The DOC-DER agreed that the proposal may make sense for some interruptible customers, and would be reasonable as long as Great Plains had sufficient firm capacity available to serve them, and as long as the higher firm rates were charged for the firm service provided which he recommended be reflected in test year revenues.[630]

532. The DOC-DER also recommended an adjustment to test year revenue, $3,222, to account for the resulting usage of firm, higher-rate volumes by interruptible customers taking advantage of the tariff change.[631] The DOC-DER's recommended adjustment would increase revenue and, thus, decreased the revenue deficiency for the test year.

533. Great Plains agreed to the DOC-DER's recommended tariff language changes that ensure that the proposed service would be available only if sufficient firm capacity is available, but not to the DOC-DER's upward test year revenue adjustment.[632]

534. Great Plains stated that existing interruptible service customers are unlikely to determine that firm service is now required because of the addition of the first-through-the-meter option. Great Plains further explained that interruptible customers with firm service requirements would have to ensure firm deliveries through separate metering under the Firm General Service Rate because this option was not previously available.[633]

535. The DOC-DER responded that if only new customers, not current interruptible customers, are likely to choose this new service option, as Great Plains believes, then "it is unclear that this proposed tariff change is in fact necessary."[634] In other words, an adjustment is necessary because firm rates are higher than interruptible

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[627] Evidentiary Hearing Tr. at 87-88 (Aberle).
[628] *Id.*
[629] *Id.*
[630] Ex. 211 at 69-72 (Heinen Direct).
[631] *Id.*
[632] Ex. 27 at 21-22 (Aberle Rebuttal).
[633] Ex. 214 at 31-32 (Heinen Surrebutal).
[634] *Id.* at 34.

rates and it is likely that new or existing interruptible customers will take advantage of the tariff change; otherwise the need for this tariff would be questionable.[635]

536. The Administrative Law Judge agrees that approval of Great Plains' First-Through-The-Meter proposed tariff change is reasonable with the agreed upon language change to clarify that this proposed service is only available if sufficient firm capacity is available, and as long as test year revenue reflects the likely higher revenue associated with firm sales to current or future interruptible customers of approximately $3,222.

D. Service and Main Extensions

537. The DOC-DER provided extensive analysis of Great Plains' new service extensions tariff language, in accordance with the Commission's directives in its March 31, 1995, *Order Terminating Investigation and Closing Docket* in Docket No. G999/CI-90-563 (90-563 Order).[636]

538. Based on its review, the DOC-DER concluded that Great Plains appears to have correctly administered its service and main extension tariffs.[637]

539. The Administrative Law Judge agrees that Great Plains showed that it has correctly administered its service and main extension tariffs.

E. Other Tariff Changes

540. The DOC-DER recommended approval of Great Plains' proposed tariff changes listed on pages 14 to 16 of Ms. Aberle's Direct Testimony, but rejection of any proposed tariff change that was not specifically identified.[638]

541. Great Plains agreed.[639]

542. The Administrative Law Judge agrees with that the record supports approval of Great Plains' proposed tariff changes listed on pages 14 to 16 of Ms. Aberle's Direct Testimony, and that any proposed tariff change not so-identified should be rejected.

XVI. FUTURE FILINGS AND RATE CASES

543. In its next filing Great Plains should provide cost data for its distribution system in a more complete manner. Specifically, Great Plains should provide the unit cost per foot for each recorded main size on its system as shown in Table 4 in Mr. Ruzycki's direct testimony and should not aggregate and average the main sizes

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[635] *Id.* at 34-35.
[636] Ex. 211 at 87-106 (Heinen Direct).
[637] Ex. 213 at 42 (Heinen Surrebuttal).
[638] Ex. 211 at 59 (Heinen Surrebuttal).
[639] ISSUES MATRIX at 23 (Apr. 22, 2016).

together. Additionally, Great Plains should note the vintage date of the original costs of installed mains and inflate the costs using the Handy-Whitman index in order to normalize the cost data into terms of current replacement costs such that data can be compared to each other in a cost analysis.[640]

544. The Administrative Law Judge recommends, on the basis of the testimony of DOC-DER's witness, Ms. Otis, that the Commission require Great Plains to improve its forecast methodology in future rate filings.[641]

545. The DOC-DER recommended, and Great Plains agreed, that the Commission require Great Plains to file a compliance filing that indicates whether or not in practice Great Plains did or did not follow through on its intention to not elect bonus depreciation.[642]

Based upon these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS OF LAW

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Minn. Stat. § 14.50 and Chapter 216B (2014).

2. The public and the parties received proper and timely notice of the hearing and the Applicant complied with all procedural requirements of statute and rule.

3. Every rate set by the Commission shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of Minn. Stat. §§ 216B.164, .241, 216C.05 (2014).[643]

4. The burden of proof is on the public utility to show that a rate change is just and reasonable.[644]

5. The record supports the resolution of the settled, resolved, and uncontested matters set forth in this report. These matters have been resolved in the public interest and are supported by substantial evidence.

6. Rates set in accordance with this Report would be just and reasonable.

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[640] Ex. 209 at 25-26 (Ruzycki Direct);Ex. 210 at 10(Ouanes Surrebutal).
[641] Ex. 206 at 20 (Otis Direct).
[642] *Id.*
[643] Minn. Stat. § 216B.03.
[644] Minn. Stat. § 216B.16, subd. 4.

7. Any Findings of Fact more properly designated as Conclusions of Law are hereby adopted as such.

Based upon these Conclusions of Law, the Administrative Law Judge makes the following:

RECOMMENDATION

The Administrative Law Judge recommends that:

1. Great Plains is entitled to increase gross annual revenues in accordance with the terms of this Report.

2. The Commission incorporate the agreements made by the parties in the course of this proceeding into its Order.

3. The Commission adopt the recommendations set forth in the Findings of Fact above.

4. Great Plains make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated: June 30, 2016

Barbara Case

BARBARA J. CASE
Administrative Law Judge

NOTICE

Exceptions to this Report, if any, by any party adversely affected, must be filed under the timeframes established in the Commission's rules of practice and procedure, Minn. R. 7829.2700, .3100 (2015), unless otherwise directed by the Commission. Exceptions should be specific and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Minn. R. 7829.2700, subp. 3. The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations.