

October 23, 2023

STAFF MEMORANDUM

TO: The Public Service Commission
FROM: Legal and Regulatory Staff
SUBJECT: Docket 2022.07.078 Draft Final Order

BACKGROUND

Attached to this memorandum is a draft final order for Docket 2022.07.078, concerning NorthWestern Energy's ("NorthWestern's") Application for Authority to Increase Retail Electric and Natural Gas Utility Service Rates and for Approval of Electric and Natural Gas Service Schedules and Rules and Allocated Cost of Service and Rate Design.

A diverse group of interested parties participated in this proceeding and provided commentary on and analysis of NorthWestern's request. The Montana Consumer Counsel ("MCC"), the Montana Large Customer Group ("LCG"), the Montana Environmental Information Center ("MEIC"), Federal Executive Agencies ("FEA"), Jefferson Energy Trading, LLC, Broad Reach Power, LLC ("Broad Reach"), Colstrip Energy Limited Partnership, the Human Resource Council, District XI ("HRC"), the Natural Resources Defense Council ("NRDC"), NW Energy Coalition ("NVEC"), Walmart, Inc. ("Walmart"), Renewable Northwest and 350 Montana petitioned for and were granted intervention.

On April 3, 2023, NorthWestern, MCC, LCG, FEA, and Walmart (collectively, "the Settling Parties") filed a Joint Motion to Approve Settlement with the Commission. Attached to the Joint Motion was a Stipulation and Settlement Agreement ("Settlement Agreement"). The Settlement Agreement, if approved, would authorize NorthWestern to increase rates to recover additional annual electric revenue of \$81,906,631 and additional natural gas revenue of \$18,210,987. The Settlement Agreement also included class revenue allocations that result in monthly bill increases for a typical residential customer, as discussed in the attached draft order.

The draft final order contemplates approval of the Settlement Agreement. Pages 3 through 12 of the draft order provide a summary of the disposition of each of the major issues involved in this case. In the interest of brevity, that summary will not be repeated here. Legal and regulatory staff will present the attached draft to the Commission at its October 25, 2023 business meeting, and will be available to answer questions from Commissioners.

**DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA**

In re NorthWestern Energy's Application for Authority to Increase Retail Electric and Natural Gas Utility Service Rates and for Approval of Electric and Natural Gas Service Schedules and Rules and Allocated Cost of Service and Rate Design	Docket 2022.07.078 «Today»
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Summary

1. On August 8, 2022, NorthWestern Energy (“NorthWestern”) filed its Application for Authority to Increase Retail Electric and Natural Gas Utility Service Rates and for Approval of Electric and Natural Gas Service Schedules and Rules and Allocated Cost of Service and Rate Design (“Application”). In this general rate case, NorthWestern sought to modify the electric rates set in Docket 2018.02.012 and the natural gas rates set in Docket D2016.9.68.

General Ratemaking Principles

2. Utility rates are determined by first calculating the utility’s revenue requirement, and then allocating that revenue requirement across the utility’s customer base. A utility’s revenue requirement is calculated according to the formula:

$$RR = O + D + T + (r \times B)$$

where RR represents the revenue requirement, O represents the utility’s operating expenses, D represents the utility’s depreciation expense, T represents the utility’s tax expense, r represents the utility’s allowed rate of return, and B represents the utility’s rate base, or the total book value of assets used to provide utility service. Each of these variables are measured over the course of a test year. The test year values may be modified based on known and measurable changes from the test year.

3. Once the revenue requirement has been calculated, it must be allocated across the utility’s customer classes. Different customer classes can impose different burdens on a utility’s supply, transmission, and distribution systems. Under general principles of utility ratemaking, customers that impose a greater burden on the utility system should likewise bear a greater share of the cost of the system. These general principles, however, may yield to some degree to practical and financial considerations. To mitigate excessive rate impacts in particular cases, it may be reasonable to allocate a customer class more or less than the full cost of the burdens the class imposes on the utility system.

4. NorthWestern and the intervening parties that addressed the allocation of revenue requirements and rate design relied on embedded cost of service studies (“ECOSS”). An ECOSS measures a utility’s costs by examining historical data in a company’s books and records. The costs are functionalized according to the Federal Energy Regulatory Commission’s (“FERC’s”) uniform system of accounts and classified as demand-, commodity-, or customer-related, based on the service(s) they support. Cost allocation is an inexact science; there is not a single correct approach or method. ECOSS results provide a guide for revenue allocations but are not prescriptive.

5. The present case asks the Commission to apply the revenue requirement formula and principles of cost allocation and rate design to determine just and reasonable rates for NorthWestern’s electric and natural gas services. NorthWestern’s last electric rate case used a 2017 test year with 2018 known and measurable changes. Its last natural gas rate case utilized a 2015 test year with 2016 known and measurable changes. NorthWestern’s current request uses a 2021 test year with 2022 known and measurable changes for both electric and natural gas services. In the time between these test years, NorthWestern asserts it has invested over \$835 million and \$267 million in its electric and natural gas systems, respectively. Those investments have increased NorthWestern’s rate base, operating expenses, depreciation expenses, and taxes. According to NorthWestern, its net rate base increased by approximately \$453 million and \$143 million for electric and natural gas, respectively, since the last applicable test periods. These investments are one of the primary drivers of the requested electric and natural gas revenue requirements from which rates are derived.

Procedural Overview

6. A diverse group of interested parties participated in this proceeding and provided commentary on and analysis of NorthWestern’s request. The Montana Consumer Counsel (“MCC”), the Montana Large Customer Group (“LCG”), the Montana Environmental Information Center (“MEIC”), Federal Executive Agencies (“FEA”), Jefferson Energy Trading, LLC (“Jetco”), Broad Reach Power, LLC (“Broad

Reach”), Colstrip Energy Limited Partnership (“CELP”), the Human Resource Council, District XI (“HRC”), the Natural Resources Defense Council (“NRDC”), NW Energy Coalition (“NWECC”), Walmart, Inc. (“Walmart”), Renewable Northwest and 350 Montana petitioned for and were granted intervention.

7. On April 3, 2023, NorthWestern, MCC, LCG, FEA, and Walmart (collectively, “the Settling Parties”) filed a Joint Motion to Approve Settlement with the Commission. Attached to the Joint Motion was a Stipulation and Settlement Agreement (“Settlement Agreement”) signed by the Settling Parties. *See* Joint Mot. of Northwestern Energy, the Montana Consumer Counsel, the Montana Large Customer Group, the Federal Executive Agencies, and Walmart Inc. to Approve Settlement (April 3, 2023). The Settlement Agreement, if approved, would authorize NorthWestern to increase rates to recover additional annual electric revenue of \$81,906,631 and additional natural gas revenue of \$18,210,987. The Settlement Agreement includes class revenue allocations that result in monthly bill increases for a typical residential customer as discussed below.

8. On April 5, 2023, HRC, NRDC, NWECC, 350 Montana, MEIC, and Renewable Northwest (collectively, “the Non-Settling Parties”) jointly filed a Motion for Additional Process (“Additional Process Motion”). On April 5, 2023, Broad Reach filed a Motion for Extension of Time, Continuance of Hearing, and Additional Process (“Broad Reach Motion”). Both the Additional Process Motion and the Broad Reach Motion were denied on April 7, 2023, and the Commission proceeded to conduct a 6-day hearing on NorthWestern’s Application and the Settlement Agreement.

9. This Order resolves NorthWestern’s Application. Relying on the parties’ advocacy and the Commission’s own knowledge and expertise, the Commission evaluates the multiple cost elements associated with NorthWestern’s utility operations to determine a zone of reasonableness. The Commission then looks to see if the Settlement Agreement produces a result that falls within the zone of reasonableness. The zone of reasonableness determined by the Commission does not establish the relative reasonableness of revenue amounts within the zone. Thus,

all points within the zone are equally reasonable and there is no basis for preferring a settlement result that may fall closer to either the lower or upper end of the zone. As explained fully in this Order, after careful review of the record evidence and the terms of the Settlement Agreement, the Commission finds that the Settlement Agreement represents a reasonable outcome for all parties and the public.

Electric Revenue Requirement

10. The Commission's analysis of the record results in a zone of reasonableness for the electric revenue requirement increase of \$71.3 million to \$90.6 million. The low end of the range reflects NorthWestern's rebuttal revenue requirement increase of \$105 million with adjustments to depreciation, incentive compensation expenses, stock-based compensation for non-executives, and stock-based compensation for members of the board of directors based on the positions of MCC and LCG. The low end reflects a return on equity ("ROE") of 9.19%.

11. The high end of the range reflects NorthWestern's proposal for depreciation and incentive compensation expenses. The high end of the range continues to reflect MCC and LCG's proposals for stock-based compensation for members of the board of directors and stock-based compensation for non-executives. The high end reflects an ROE of 9.78%.

12. About half of the \$19.3 million difference between the high and low end of the range of reasonableness is due to the high and low ROEs. The high and low ends for depreciation and incentive compensation each account for about 25% of the difference.

13. The Order approves an \$81,906,631 increase to the electric base revenue requirement as agreed to by the Settling Parties in paragraph one of the Settlement Agreement, given that the increase falls within the zone of reasonableness. The increase approved by the Order is \$23,220,811 less than NorthWestern's requested increase of \$105,127,442 in the electric base revenue requirement. The Commission granted NorthWestern an interim increase in its electric base revenue requirement of \$29,356,124 in Order No. 7860c effective October 1, 2022. In addition, in NorthWestern's 2023 Tax Tracker Docket

2022.12.106 the Commission approved an additional increase in the electric base revenue requirement rates of \$10,773,307 effective January 1, 2023. Thus, of the \$81,906,631 approved in this Order, \$40,129,431 is already reflected in NorthWestern's current rates being paid by customers. Overall, when compared to the electric base revenues generated by rates in effect in August 2022 when this general rate case was filed, the \$81,906,631 increase is a 14.98% increase. Compared to rates that include the interim and tax tracker adjustments, however, the bill for an average residential customer using 750 kWh per month will increase by \$8 or 7.6%.

14. The electric revenue requirement increase agreed to by the Settling Parties is based on an overall rate of return ("ROR") of 6.72% including a 9.65% ROE, a 4.01% cost of long-term debt, and a capital structure comprised of 51.98% debt and 48.02% equity. The 9.65% ROE falls within the zone of reasonableness of 9.19% to 9.78%, and the overall ROR falls within the zone of reasonableness of 6.50% to 6.78%, excluding the 8.25% ROR for NorthWestern's 30% ownership of Colstrip Unit 4.

Electric Supply Costs

15. A significant portion of NorthWestern's overall electric revenue comes from the Power Costs and Credits Adjustment Mechanism ("PCCAM"). The PCCAM tracks certain costs and credits associated with supplying electric service and allows annual rate adjustments to track actual costs incurred and credits received. In this Order, the Commission preserves the 90/10 cost-sharing provisions of the PCCAM, which requires NorthWestern's shareholders to bear 10% of certain costs in excess of the approved PCCAM Base revenue. If, through prudent management, NorthWestern incurs costs less than its approved PCCAM Base revenue, NorthWestern's shareholders will be entitled to retain 10% of the savings associated with certain costs. Otherwise, the PCCAM passes through the tracked costs without allowing NorthWestern to earn a return on those costs.

16. The Commission approves a PCCAM Base of \$208,282,098, as agreed to by the Settling Parties. This is an increase of \$69,616,395 or 50.2% compared to

the prior PCCAM Base, which was \$138,655,703. In Interim Order No. 7860c, the Commission approved a PCCAM Base of \$199,802,510, which became effective on October 1, 2022. Thus, the PCCAM Base approved in this Order is an increase of \$8,479,588 or 4.2% from NorthWestern's current rates. In addition, the Order requires that capacity costs shall be subject to the 90/10 cost-sharing, the PCCAM shall be subject to quarterly adjustments, and interest shall be applied symmetrically on any deferred balances.

Electric Revenue Allocation

17. This Order accepts the electric revenue allocation agreed to by the Settling Parties, which allocates the increased electric revenue requirement across NorthWestern's customer classes in a manner that moves closer to the cost-causer, cost-payer principle, but not entirely. The electric increase is allocated across a variety of customer classes ranging from a zero percent increase for the GS-1 Primary and GS-2 Transmission classes to a 6.34% increase for Irrigation, a 16.4% increase for Lighting, and a 18.2% increase for GS-2 Substation. In an effort to bring their rates closer to costs, the Residential and GS-1 Secondary customer classes receive increases of 18.2% and 13.6% respectively.

Electric Rate Design

18. The Order accepts the electric rate design agreed to by the Settling Parties, which includes minimal changes from current rate designs. Only the GS-2 Substation class receives an increase in the monthly service charge and lighting rate categories are consolidated.

Natural Gas Revenue Requirement

19. The Commission's analysis of the record results in a zone of reasonableness of \$15.8 million to \$23.1 million for the gas revenue requirement increase. The low end of the range reflects NorthWestern's rebuttal revenue requirement increase of \$26.6 million with adjustments to depreciation, incentive compensation expense, stock-based compensation for non-executives, and stock-based compensation for members of the board of directors based on the positions of the MCC and LCG. The low end also reflects the production asset revenue

requirement step-down and an ROE of 9.19%.

20. The high end of the range reflects NorthWestern's proposal for depreciation and incentive compensation expense. The high end continues to reflect MCC and LCG's proposals for stock-based compensation for members of the board of directors and stock-based compensation for non-executives. The high end also reflects the production asset revenue requirement step-down and an ROE of 9.78%.

21. The Order approves the Settlement Agreement's stipulated natural gas 2022 revenue requirement increase of \$18,210,987, given that it falls within the zone of reasonableness. As the new natural gas rates will be implemented in 2023, the Order reduces the increase that can be reflected in the natural gas rates by \$738,928 to reflect the 2023 Production Asset Revenue Requirement stepdown. This reduces the natural gas revenue requirement increase to \$17,472,059. The increase approved by this Order is a \$9,116,461 reduction from the \$26,588,520 increase NorthWestern requested in its rebuttal. The Commission granted NorthWestern an interim increase for its natural gas revenue requirement of \$1,727,788 in Order No. 7860c, effective October 1, 2022. In addition, the Commission approved an additional increase in the natural gas revenue requirement of \$2,855,048 effective January 1, 2023, in NorthWestern's 2023 Tax Tracker Docket 2022.12.106. Thus, of the \$17,472,059 approved in this Order, \$4,582,846 is already reflected in NorthWestern's current rates being paid by customers. Overall, when compared to the natural gas base revenues generated by rates in effect in August 2022 when the general rate case was filed, the \$17,472,059 increase is a 11.8% increase. However, when compared to natural gas base revenues generated after the interim and property tax adjustments, the increase is 8.3%.

22. The natural gas revenue requirement increase is based on an overall ROR of 6.67% including a 9.55% ROE, a 4.01% cost of long-term debt, and a capital structure comprised of 51.98% debt and 48.02% equity. The ROE falls within the zone of reasonableness of 9.19% to 9.78%, and the overall ROR falls within the zone of reasonableness of 6.50% to 6.78%.

Natural Gas Revenue Allocation

23. The natural gas increase is also allocated across a variety of customer classes. The Residential Employee, Utilities, DBU Firm Transportation, TBU Firm Transportation, the DBU Interruptible Transportation, and TBU Interruptible Transportation all receive an approximately 14% increase. The Residential, General Service, and Storage customer classes all receive an increase of approximately 11%.

Natural Gas Rate Design

24. The Order accepts the natural gas rate design agreed to by the Settling Parties, which adopts the natural gas monthly service charges as set forth in the testimony of NorthWestern's witness Cynthia Fang. With this rate design, only non-residential classes receive an increase in the monthly service charges.

Riders

25. The Settling Parties agreed that the Reliability Rider would not be approved in this proceeding. Through the Settlement Agreement, NorthWestern has withdrawn its request for the Reliability Rider and, therefore, the only findings necessary to resolve this issue relate to the Settling Parties' agreement that NorthWestern may file a one-time update of the PCCAM Base Costs when the Yellowstone County Generating Station ("YCGS") is placed into service. This Order finds that the Settlement Agreement represents a reasonable compromise. The Order requires NorthWestern's PCCAM Base Cost update application to include all information necessary for the Commission to conduct a full prudence review regarding the YCGS so that the Commission may determine whether the plant is in the public interest.

26. The Settling Parties agreed that the Business Technology Rider would not be approved. Through the Settlement Agreement, NorthWestern has withdrawn its request for the Business Technology Rider and, therefore, no findings are necessary on this issue.

27. The Settling Parties agreed that NorthWestern's proposed Wildfire Mitigation Rider would not be approved but that NorthWestern will defer incremental wildfire mitigation expenses subject to annual caps specified in Exhibit E of the Settlement Agreement. Those deferred expenses are eligible for recovery,

subject to a Commission prudence determination, in a future rate review. Through the Settlement Agreement, NorthWestern has withdrawn its request for the Wildfire Mitigation Rider and, therefore, the only findings necessary to resolve this issue relate to the deferred accounting for future incremental wildfire expenses. The Order finds deferred accounting as agreed to by the Settling Parties represents a reasonable compromise.

Miscellaneous Issues

28. The Settling Parties agree that demand-side management (“DSM”) costs will not be capitalized and will continue to be recovered through the PCCAM. Through the Settlement Agreement, NorthWestern has withdrawn its request to capitalize DSM costs and no findings are necessary on this issue.

29. NorthWestern proposes to defer and accumulate costs associated with small natural gas production asset acquisitions for recovery in a future rate review, subject to a Commission prudence determination. The Settlement Agreement does not address this issue. The Order finds that NorthWestern’s proposal is reasonable.

30. NorthWestern’s proposed natural gas rate base and operating and maintenance expenses reflect its acquisition of the Sleepy Hollow gas system. The rate base and expense impacts are described in NorthWestern’s response to Data Request MCC-337. Due to the limited financial data available when NorthWestern acquired the system and the potential for unanticipated expenses to operate and maintain the system, NorthWestern proposes to defer and accumulate any costs that exceed the 2022 known and measurable expense adjustment. The Settling Parties agreed that deferred cost treatment is reasonable. The Order concurs with Settlement Agreement.

31. The Settling Parties agreed to the elimination of the Fixed Cost Recovery Mechanism (“FCRM”) pilot approved in Docket 2018.02.012. The Order finds that elimination of the FCRM pilot is a reasonable resolution of the issues surrounding that mechanism in this case.

32. In the Settlement Agreement, NorthWestern agrees to file concurrently with its next general electric rate review application a comprehensive

jurisdictional cost of service study of all costs associated with providing wholesale services. The Settling Parties reserve their rights to advocate any position regarding the study and whether and how the study may or may not be used in that or future proceedings. The Order finds the Settlement Agreement on this point reasonable and appropriate given that the Commission's questions regarding the reasonableness of the revenue crediting method, raised in NorthWestern's last rate review, remain unanswered.

33. The Settling Parties accept the lighting tariff changes set forth in the testimony of NorthWestern's witness Cynthia S. Fang. The Order finds that those lighting tariff changes are reasonable.

34. The Settling Parties accept the tax portion of the electric and natural gas revenue requirements as proposed in the testimony of NorthWestern's witness Aaron Bjorkman, which describes adjustments to income tax expenses and Accumulated Deferred Income Taxes ("ADIT") related to rate base. The Order finds that those tax adjustments are reasonable.

35. The Settling Parties agree to the monthly natural gas service charges set forth in the testimony of NorthWestern's witness Cynthia S. Fang. The Order finds that those monthly service charges are reasonable.

Procedural History

36. On August 8, 2022, NorthWestern filed its Application for Authority to Increase Retail Electric and Natural Gas Utility Service Rates and for Approval of Electric and Natural Gas Service Schedules and Rules and Allocated Cost of Service and Rate Design (“Application”).

37. NorthWestern’s Application included a request for an interim increase in electric and natural gas rates pending a final decision by the Commission. NorthWestern Appl. for Interim Rate Increases (Aug. 8, 2023). The interim electric increase was designed to produce \$114,704,788 of additional annual revenues and the interim natural gas increase was designed to produce \$5,766,786 of additional annual revenues. Notice of Interim Rate Adjustment Request (August 8, 2023).

38. On August 12, 2022, the Commission issued a Notice of Application and Intervention Deadline, establishing a September 1, 2022, deadline for petitions to intervene.

39. Timely petitions to intervene were filed by MCC, LCG, MEIC, FEA, Jetco, Broad Reach, CELP, HRC, NRDC, NWECA¹, Renewable Northwest, and 350 Montana. On September 13, 2022, by Notice of Staff Action, the Commission granted all petitions to intervene. The Commission separately approved a late petition for intervention from Walmart.

40. On October 1, 2022, the Commission issued Interim Order 7860c authorizing NorthWestern to temporarily increase its electric and natural gas service rates to recover \$29,356,124 and \$1,727,788 of additional annual electric and natural gas utility revenues, respectively. In addition, the Commission authorized NorthWestern to increase PCCAM rates to recover additional base revenues of \$61,146,807 per year. Order 7860c ¶¶ 10, 17.

41. On December 18, 2022, MCC, LCG, MEIC, FEA, HRC/NRDC/NWECA, Broad Reach, 350 Montana, Renewable Northwest, and Walmart filed intervenor

¹ HRC, NRDC and NWECA filed a joint petition to intervene and will be referred to collectively herein as HRC/NRDC/NWECA.

testimony.

42. On March 6, 2023, NorthWestern filed its rebuttal testimony.

43. On April 7, 2022, the Commission received the Settlement Agreement between NorthWestern, MCC, LCG, FEA, and Walmart.

44. The Commission conducted a public hearing from April 11–18, 2023, and received public comment at the beginning of each hearing day.

45. Post-hearing briefing concluded on June 27, 2023.

Analysis

I. Revenue Requirement

A. Cost of Capital

i. Parties' Positions

a. Capital Structure and Cost of Debt

46. NorthWestern's electric and natural gas revenue requirement calculations reflected a capital structure of 51.98% debt and 48.02% equity and a long-term cost of debt of 4.01%. Pursuant to Order 6925f ¶ 264, Docket D2008.6.69, the capital structure for Colstrip Unit 4 is 50% debt and 50% equity and the cost of debt is 6.5%. Test. Crystal Lail 54–55, 61 (Aug. 8, 2022). No party contested those figures.

b. Cost of Equity

47. NorthWestern proposed a ROE based on an analysis of a proxy group of publicly traded utilities with similar risk profiles. Test. Adrien McKenzie 3, 17 (Aug. 8, 2022). NorthWestern used multiple analytical models to estimate ROEs for the proxy group, including: a constant growth discounted cash flow model ("DCF"), a capital asset pricing model ("CAPM"), an empirical CAPM ("ECAPM"), and an equity risk premium approach. *Id.* at 33–60. Northwestern's DCF growth projections relied on analysts' earnings per share ("EPS") forecasts and the sustainable growth rate for each firm in the proxy group of companies. *Id.* at Ex. AMM-4, at 2. NorthWestern's CAPM incorporated a cost of common equity for the

market as a whole of 13.1%, which contributed to a market equity risk premium (“ERP”) of 10.3%. Test. McKenzie 50. Northwestern’s ECAPM used a weighted ERP, where the market risk premium was assigned a weight of 25% and the company-specific risk premium based on the stock’s relative volatility was assigned a weight of 75%. *Id.* at 54. Northwestern’s risk premium approach estimated the cost of equity by first determining the additional return investors require to forgo the relative safety of bonds, and then adding this equity risk premium, based on surveys of previously authorized ROEs, to the current yields on bonds. *Id.* at 56.

48. NorthWestern’s analysis resulted in a range of ROEs from 9.70% to 11.00% with a midpoint of 10.35%. Test. McKenzie 3. NorthWestern’s ROE range also included a 10-basis point adjustment for flotation costs—legal, accounting, brokering and other costs associated with the issuance of common stock—which NorthWestern stated were not included in rate base. *Id.* at 63–69. NorthWestern contended that those issuance costs must be included for the revenue requirements to reflect all costs incurred to raise funds from investors. *Id.* at 64–65. From the 10.35% midpoint of its range of ROEs, NorthWestern then added a 25-basis point risk adjustment to account for the sharing provisions of its PCCAM and other regulatory mechanisms approved for proxy group utilities but not NorthWestern. *Id.* at 81. NorthWestern asserted the adjustment was needed to account for attrition—the “shortfall between a utility’s actual return and the allowed return approved by” the Commission—and regulatory lag. *Id.* at 29–31. Adding the 25-basis point “risk adjustment” to the midpoint of the range of NorthWestern’s ROE calculations produced NorthWestern’s proposed ROE of 10.60%. *Id.* at 81.

49. MCC and LCG provided joint testimony addressing NorthWestern’s ROE. They applied the DCF and CAPM analytical models to NorthWestern’s selected proxy group, which resulted in ROEs of 8.8% and 9.0%, respectively. Test. David Garrett 3–4 (Dec. 19, 2022). Given those results, the parties proposed an alternative ROE of 9.0%. *Id.* Although they used the same proxy group and two of the same models as NorthWestern, their results differed because they assumed different growth rates and ERPs in the DCF and CAPM, respectively. *Id.* at 36–44.

MCC and LCG's DCF growth projections were weighted, with one-third of the total weight assigned to the long-term forecast of nominal GDP and two-thirds assigned to short-term dividend growth rate estimates published by Value Line. *Id.* at 43. MCC and LCG's CAPM ERP incorporated the results of surveys, implied ERP calculations, and the ERP as reported by Kroll. Test. Garrett 56. Ultimately, the parties concluded a 9.0% ROE—which is the average of NorthWestern's various DCF models—was reasonable. *Id.* at 44.

50. FEA identified concerns with NorthWestern's DCF, CAPM, ECAPM, Utility Risk Premium, and Expected Earnings models and disagreed with the 10-basis point adjustment for flotation costs, asserting that it was not based on verifiable, reasonable costs. Test. Christopher C. Walters 67–68 (Dec. 19, 2022). FEA also opposed NorthWestern's 25-basis point risk adjustment, contending it would have no effect on NorthWestern's ability to earn its authorized ROE. *Id.* at 71. FEA performed ROE analyses using the DCF, Risk Premium, and CAPM models and proposed an alternative ROE range of 8.9% to 10.0%. *Id.* at 2. FEA recommended an ROE of 9.45% based on the midpoint of its model results. *Id.* at 53, Table CCW-12.

51. Walmart recommended that the Commission look to the ROEs approved by other state regulatory commissions and the risk-reducing nature of the new riders and mechanisms NorthWestern proposed in this case. Test. Alex J. Kronauer 4–5 (Dec. 19, 2022). However, Walmart did not offer a specific ROE proposal.

ii. Discussion and Findings

52. NorthWestern's proposed capital structure and cost of debt figures were not contested. The record evidence supports NorthWestern's assertion that its requested capital structure is reasonably in-line with comparable utilities in the proxy group. Test. McKenzie 84–87. The Commission finds that it is reasonable to use NorthWestern's proposed capital structure to evaluate the reasonableness of the revenue requirement increase in the Settlement Agreement.

53. The Commission evaluates the ROE used to set utility rates according to well-established regulatory case law generally referred to as the fair return standard. There are three prongs to the standard: (1) a utility's ROE should be commensurate with those of businesses with similar risk; (2) the ROE should be sufficient to maintain the financial integrity of the utility; and (3) the ROE should be adequate to enable the utility to attract investors and capital on reasonable terms. *Fed. Power Comm'n. v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944); *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679, 692–93 (1923).

54. Despite differing on the assumptions used in their DCF models, the parties' ROE proposals were similar. NorthWestern's growth projections relied on analysts' EPS forecasts for the proxy group companies, which reflect investors' expectations. Test. McKenzie 3, 17. MCC and LCG's growth projections were based on the long-term forecast of nominal GDP, weighted by one-third, and short-term dividend growth rate estimates published by Value Line, weighted by two-thirds. Test. Garrett 43. Although practical growth constraints such as nominal GDP may not necessarily restrict investor expectations, and dividend growth rates may not be relied on as frequently as EPS growth (*see* Reb. Test. Adrien McKenzie 39 (Mar. 6, 2023)), the Commission finds MCC and LCG's growth projections reasonable. The remaining DCF model inputs used by the parties, which included stock prices and dividends, did not significantly impact their respective results. With respect to DCF model results, the Commission finds that a range of reasonableness is bounded by MCC and LCG's ROE of 8.8% and NorthWestern's average ROE of 9.0%.

55. The parties' CAPM model results were primarily affected by the assumed expected market rate of return ("RM"). The Commission finds NorthWestern's RM of 13.1%, which contributes to an assessed ERP of 10.3% (*see* Test. McKenzie 50), overly optimistic and inconsistent with current expectations of market participants. As noted by MCC and LCG, the 2022 IESE Business School Survey reported an average ERP of 5.6%. Test. Garrett 53. At most, the Commission finds that the ERP should not exceed 7.9%, which reflects the average

of Northwestern and MCC/LCG's respective positions. Excluding the 4.8% ERP (*see* Test. Garrett 56) as an outlier, the average of MCC and LCG's remaining ERPs of 5.73% represents a reasonable minimum ERP within the CAPM. These inputs, inclusive of a beta of 0.89 and a risk-free rate of 3.45%, result in a CAPM ROE range of 8.5% to 10.5%.

56. In its analysis of an overall range of reasonableness for the ROE, the Commission does not rely on NorthWestern's forecasted bond yield analysis. Test. McKenzie 52. The Commission finds that analysis similarly reflects an overly optimistic RM of 13.1%, which significantly impacts the resulting ROE. *Id.* at 50. Nor does the Commission rely on NorthWestern's ECAPM, which attempts to account for the fact that low-beta stocks tend to exhibit higher returns than predicted by the standard CAPM. *Id.* at 52. While the ECAPM is used frequently and is supported in the financial literature, there are several legitimate concerns with the model in this case, including: raw betas for each of the utility stocks in the proxy group are already adjusted by Value Line, the beta-adjustment method used by Value Line may overstate betas in low-beta industries like utilities, and the ECAPM uses other inputs such as an overestimated ERP. Test. Garrett 63. Furthermore, a size adjustment is inappropriate, as the record contains compelling arguments that the size effect was a short-lived phenomenon and no longer exists *Id.* at 65–66.

57. NorthWestern supported its ROE using a utility risk premium analysis that estimates investors' required ROR by adding an ERP to observable bond yields. Test. McKenzie 56–57. In the analysis, ERP was derived by subtracting the average yield on public utility bonds from base ROEs for public utilities authorized by regulatory commissions across the country. *Id.* at 56–58. The Commission finds persuasive arguments by intervenors that the analysis, which incorporated ROEs authorized as much as 50 years ago, does not reflect forward-looking investor expectations. Test. Garrett 60–61.

58. NorthWestern provided an expected earnings analysis in which returns on book value are compared to the allowed return of the utility. Test.

McKenzie 61–63. Expected earned returns on invested capital are said to provide a benchmark for investors’ opportunity costs. *Id.* at 61. In this case, the analysis results in a ROE of 11.0%. Test. McKenzie 63. However, the Commission agrees with intervenors that the analysis did not measure the cost of equity (or required ROE) and it is preferable to use traditional cost of equity models (CAPM, DCF) to determine an authorized ROE.

59. The Commission is not persuaded by NorthWestern’s evidence in favor of a 25-basis point “risk adjustment.” *See* Test. McKenzie 81. The impacts of regulatory lag are not uniform or predictable enough to justify a 25-basis point adder to NorthWestern’s ROE. The Commission is also unpersuaded by NorthWestern’s rationale for a 10-basis point addition to ROE for flotation costs. As NorthWestern’s witness observed, there is no current accounting treatment to recognize equity flotation costs. Test. McKenzie 64. A 10-basis point adder to NorthWestern’s ROE is not a reasonable way of compensating shareholders for unquantified flotation costs. Instead, the Commission is persuaded by intervenors’ arguments that flotation costs are not actual “out-of-pocket” costs and the market accounts for flotation costs.

60. The above findings result in ROE ranges of 8.8% to 9.0% for the DCF model and 8.5% to 10.5% for the CAPM model. The Commission applies a weighting of 55% in favor of the CAPM results to account for evidence that the CAPM is the most widely used model for estimating ROE. For purposes of evaluating the revenue requirement increase in the Settlement Agreement, the Commission uses an ROE range of reasonableness of 9.19% to 9.78%. The low end of the range is the weighted average of the low DCF of 8.8% and median CAPM of 9.5%. The high end of the range is the weighted average of the median DCF of 8.9% and the high CAPM of 10.5%.

B. Depreciation Expense

i. Parties’ Positions

61. Depreciation rates currently used by NorthWestern for electric and

common properties serving Montana are based on Final Order No. 7604u, Docket 2018.02.012. Depreciation rates currently used for natural gas properties are based on Final Order No. 7522g, Docket 2016.09.068. The depreciation rates NorthWestern proposed in those two dockets were based on studies conducted in 2018 (electric) and 2016 (natural gas). Test. Ronald White 3, 4 (Aug. 8, 2022).

62. NorthWestern engaged Foster Associates to conduct a 2022 depreciation study for electric, natural gas, and common properties subject to the Commission's jurisdiction. Test. White 1. NorthWestern is currently using an approved depreciation system composed of the straight-line method, vintage group procedure, and remaining life technique. *Id.* at 8. In the 2022 depreciation study, NorthWestern continued using that depreciation model. *Id.* at 9.

63. NorthWestern used the depreciation study results to calculate its adjustments to depreciation expense. NorthWestern recommended test year depreciation expense of \$148,243,211 for the electric utility, which was a \$12,580,275 increase in annual depreciation. Test. Jeffrey B. Berzina 23 (Aug. 8, 2022). NorthWestern recommended test year depreciation expense of \$30,834,975 for the natural gas utility, which was an increase in annual depreciation expense of \$3,980,983. *Id.* at 31.

64. MCC proposed a reduction in the electric depreciation expense proposed by NorthWestern in the amount of approximately \$3,962,924 and a reduction in the natural gas depreciation expense proposed by NorthWestern in the amount of approximately \$3,183,367. Test. Ralph C. Smith Ex. RCS-1 4, Ex. RCS-2 4 (Dec. 19, 2022). MCC used the same historical property data as NorthWestern but applied a different depreciation model—the straight-line method, average life procedure, remaining life technique, and broad group model. *Id.* at 77.

65. MCC used a mathematical curve-fitting technique to select an Iowa Curve to get an objective, mathematical assessment of how well the curve fits to the observed life table curve ("OLT curve"). Test. Garrett 78. MCC's analysis not only considered the entirety of the OLT curve, but also involved fitting Iowa curves to the most significant part of the OLT curve for certain accounts. *Id.* at 79, 81. MCC

proposed longer service lives for specific accounts where it found NorthWestern's estimated Iowa curves were too short to provide the most reasonable mortality characteristics of the account. *Id.* at 81. MCC argued that NorthWestern did not provide any convincing evidence outside of the historical data to support its proposals, and therefore, proposed to focus on statistical analysis when selecting service life estimates. *Id.* at 82. Overall, MCC proposed adjustments to both electric and gas transmission and distribution accounts. *Id.* at 83–106.

66. LCG co-sponsored the depreciation expense adjustment recommended by MCC. Test. Kevin C. Higgins 24 (Dec. 19, 2022). LCG also included an incremental decrease to accumulated depreciation, partially offset by an increase to ADIT, to reflect the rate base impact of MCC's proposed depreciation rates. *Id.* at 24. That adjustment resulted in an overall reduction of \$3,817,974 to the Montana electric jurisdiction depreciation expense as proposed by NorthWestern, all of which LCG applied to the Transmission and Distribution ("T&D") revenue requirement. *Id.*

67. FEA conducted an actuarial analysis based on NorthWestern's model and concluded that the resulting depreciation rates would produce an excessive level of depreciation expense, thus overstating the requested revenue requirement. Test. Brian C. Andrews 2 (Dec. 19, 2022). FEA contended that NorthWestern overstated the depreciation rates for its wind production assets by using a 25-year average service life for both Spion Kop and Two Dot Wind. *Id.* FEA asserted that a 30-year life for the wind facilities was reasonable and aligned with a recent industry survey of the expected useful life of such facilities. FEA's service life adjustment reduced the test year depreciation expense by approximately \$1.1 million. *Id.* at 3. In addition, FEA recommended increasing the service lives of four T&D Plant Accounts, which reduced the electric depreciation expense by approximately \$3.3 million. *Id.*

68. Finally, FEA contended NorthWestern's Statement I contained formula errors in the supporting Excel files, which resulted in the use of incorrect depreciation rates from the depreciation rate study. Test. Brian C. Andrews 3 (Dec.

19, 2022). The errors resulted in an overstatement of 2022 depreciation expense by approximately \$1.1 million. *Id.* Overall, FEA recommended the Commission reject NorthWestern’s proposed electric depreciation expense and approve FEA’s reduction of approximately \$5.4 million. *Id.*

69. In rebuttal, NorthWestern updated total electric depreciation and amortization expense to \$144,933,586 and total gas depreciation and amortization expense to \$31,365,741. NorthWestern addressed and corrected the errors found by FEA, in addition to others. Reb. Test. Jeffrey B. Berzina 14, 18 (Mar. 6, 2023).

70. NorthWestern opposed FEA’s proposal to increase the service lives of the wind facilities to 30 years. Reb. Test. Berzina 4. NorthWestern asserted that the Commission’s Orders 7159l, in Docket D2011.5.41, and 7604q, in Docket 2018.02.012, established 25-year estimated lives for the wind farms. *Id.* at 19. NorthWestern argued that FEA’s 30-year service life was not based on project-specific engineering or economic analysis, but rather a Lawrence Berkeley National Laboratory survey average that contained assumptions likely irrelevant to NorthWestern’s specific wind farms. *Id.* at 21.

71. NorthWestern argued MCC, LCG, and FEA did not assert or demonstrate that the depreciation rates recommended by NorthWestern were mathematically incorrect, inconsistent with the goals of depreciation accounting, or outside the zone of reasonableness. Reb. Test. Ronald E. White 1–2 (Mar. 6, 2023). NorthWestern asserted that the adjustments made by MCC, LCG, and FEA were aimed solely at reducing depreciation expense. *Id.* NorthWestern questioned the depreciation model used by MCC and LCG, asserting that it was merely a computerized version of visual curve fitting techniques. *Id.* at 7–8. According to NorthWestern, “[v]isual curve fitting is an application of *descriptive statistics* used to summarize and describe data through numerical calculations, graphs, or tables. It is not an actuarial method of life analysis.” *Id.* at 8 (emphasis in original). NorthWestern contended that the statistical techniques it employed were technically more rigorous than the “visual curve fitting” employed by MCC and LCG. *Id.* at 10. NorthWestern noted that its depreciation studies with similar

techniques were accepted by the Commission in previous dockets. *Id.* at 11. NorthWestern argued that the recommendations of MCC and LCG should be rejected due to false assertions, flawed analyses, errors, inconsistencies, and omissions in their analysis. *Id.* at 16.

ii. Discussion and Findings

72. The Commission recognizes NorthWestern has historically used the depreciation system composed of the straight-line method, vintage group procedure, and remaining life technique. The Settling Parties did not, however, arrive at a consensus with respect to the methodology that should be used in the future. Post-Hr’g Br. of LCG and FEA 6 (May 24, 2023). In this Order, the Commission does not find any particular method for calculating depreciation to be its preferred methodology. That said, with the errors corrected in NorthWestern’s rebuttal, the Commission finds NorthWestern’s proposal to be the high end of the range of reasonableness.

73. The Commission also finds merit in MCC’s focus on statistical analysis when selecting service life estimates. Depreciation systems are designed to allocate costs in a rational manner to allow recovery of the original cost of a prudent investment. The Commission finds no reason in the present record to disregard entirely the role of statistical analysis in achieving a rational allocation of costs. But for the Settlement Agreement, the Commission expects that a more robust record on the advantages and disadvantages would have been developed by MCC and NorthWestern at the hearing. The Commission, while recognizing the possible waste that may be caused by underestimating service lives, finds MCC’s proposal to be on the low end of a range of reasonableness.

74. The Commission also considered FEA’s and LCG’s additional issues and adjustments. NorthWestern corrected FEA’s identified issue in rebuttal, and the Commission is not persuaded that FEA’s analysis of the service lives of the wind farms merits FEA’s adjustment. As NorthWestern pointed out, FEA’s service life adjustment was not based on an analysis of NorthWestern’s wind assets. Furthermore, LCG did not provide a thorough explanation of its ADIT additional

adjustment to Mr. Garrett's proposal. The Commission finds MCC's proposed reduction in electric depreciation expense of approximately \$3,962,924 and a reduction in the natural gas depreciation expense of approximately \$3,183,367 to be a low-end of a range of reasonableness.

C. Property Taxes

i. Parties' Positions

75. NorthWestern proposed to reset the base property tax level from which annual property tax tracker adjustments were calculated. Test. Arron J. Bjorkman 31 (Aug. 8, 2022). NorthWestern's initial filing included an estimate of property taxes for 2022, which resulted in a required revenue increase of \$11,122,925 for electric and \$2,566,502 for gas. Test. Andrew Durkin, Ex. ADD-1 (Aug. 8, 2022). NorthWestern's rebuttal filing reflected full recovery of property taxes incurred. Reb. Test. Elaine Rich 25 (Mar. 6, 2023). NorthWestern updated its property tax required revenue increase to \$14,529,164 for electric and \$4,150,562 for gas. *Id.* at Exs. EAR-1, EAR-2. No party opposed updating NorthWestern's electric and natural gas property taxes to 2022 actuals.

ii. Discussion and Findings

76. NorthWestern's right to recover property taxes is established in statute. Mont. Code Ann. § 69-3-308. Historically, the Commission has approved updating the property tax tracker base in NorthWestern's rate cases. In the tax tracker, Docket 2019.11.089, rates reflected an updated base approved in the prior electric rate case, Docket 2018.02.012. The Commission finds that the actual property taxes reported by NorthWestern are accurate and should be included in rates. The Commission therefore finds NorthWestern's base revenue to recover property taxes should be updated to \$14,529,164 for electric service and \$4,150,562 for gas service, as presented in NorthWestern's rebuttal.

D. Tax Portion of the Electric and Natural Gas Revenue Requirements

i. Parties' Positions

77. NorthWestern added several deductions and adjustments to its electric and natural gas revenue requirements concerning tax related issues. Some of NorthWestern's deductions and adjustment concerned income tax deductions for repairs, income tax deductions for meters, and payroll taxes, among other tax related issues. Test. Bjorkman 3; Appl. Statement J 1.

78. Intervenors contested several of NorthWestern's deductions and adjustments concerning tax-related issues including income tax deductions for repairs, income tax deductions for meters, payroll taxes, and income tax credits for research activities.

79. Concerning NorthWestern's income tax deductions for repairs, both MCC and LCG had concerns regarding the amount of repairs deduction used by NorthWestern in calculating federal income taxes. Test. Ralph Smith 74–76; Test. Higgins 5, 10.

80. Concerning NorthWestern's payroll taxes, MCC disagreed with NorthWestern including Social Security and Medicare taxes in its expense adjustments for labor, incentive compensation, and stock-based compensation for non-executive employees. Test. Smith 68. Overall, MCC recommended a \$381,583 reduction in payroll tax expenses. *Id.* Concerning NorthWestern's income tax deduction for meters, MCC recommended adjustments to the amount of tax deductions for meters that NorthWestern utilized in calculating income taxes. *Id.* at 89.

81. Concerning income tax credits for research activities, NorthWestern did not claim any income tax credits for increasing research activities. Data Resp. MCC-296(d) (Dec. 12, 2022). MCC recommended an adjustment to reflect a normal level of these activities. Test. Smith 92. MCC's adjustment reduced the income tax expense for NorthWestern's electric and gas utilities by \$341,393 and \$84,881, respectively.

82. MCC also proposed rate base adjustments for ADIT related to deferred revenue from certain electric transmission interconnection projects, accrued

property taxes, accrued incentive compensation, pension and benefit reserves, and environmental reserves. Test. Ralph Smith 33–42.

83. NorthWestern addressed several tax issues relating to operating income. NorthWestern first addressed the income tax deduction for repairs. In the initial filing, NorthWestern originally used repair deductions of \$63.6 million and \$13.0 million respectively for the electric and natural gas income tax calculations. Appl. Electric Statement J 3, Natural Gas Statement J 3. MCC asserted those deductions should be \$69.5 million and \$20.0 million respectively based on a six-year average. Test. Smith 75–76. LCG proposed the deduction be increased to \$77.3 million and \$14.9 million respectively which were the 2021 actual amounts. Test. Higgins 23, 55, Ex. KCH-8 1, Ex. KCH-18 1. In response to LCG’s and MCC’s adjustments, NorthWestern updated the repairs deductions for electric and natural gas to the 2022 actual amounts of \$75.8 million and \$13.5 million, respectively. Reb. Test. Aaron J. Bjorkman 5–6 (Mar. 6, 2023). Second, NorthWestern addressed payroll taxes. NorthWestern’s rebuttal testimony generally agreed with MCC’s position. *See id.* at 12–13 (explaining acquiescence to MCC’s rate base adjustment for post-employment benefits).

84. Third, NorthWestern addressed its income tax deduction for meters. In its initial filing NorthWestern had used meter deductions of \$21.0 million and \$0.021 million respectively for the electric and natural gas income tax calculations. Appl. Electric Statement J 3, Natural Gas Statement J 3. MCC asserted those deductions should be \$9.3 million and \$4.2 million respectively. Test. Ralph Smith 89, Ex. RCS-1, Ex. RCS-2. In rebuttal testimony, NorthWestern used 2022 actual meter deductions of \$10.7 million and \$4.1 million for the electric and natural gas utilities. Reb. Test. Bjorkman 7. NorthWestern asserted MCC’s methodology is unexplained and accepting MCC’s position would result in a higher revenue requirement. *Id.* at 7–8.

85. Fourth, NorthWestern addressed its income tax credits for research activities. MCC proposed tax credits reducing federal income tax expenses for the electric and natural gas utilities of \$341,393 and \$84,881 respectively. MCC

proposed credits were based on 2021 actual NorthWestern credits. In rebuttal, NorthWestern proposed credits for the electric and natural gas utilities of \$122,902 and \$27,373 respectively. The proposed NorthWestern credits reflect the four-year average of the actual credits for the years 2018-2021. *Id.*

86. In its rebuttal testimony, NorthWestern also addressed each of MCC's proposed ADIT related rate base adjustments.

87. First, NorthWestern addressed the deferred revenue from certain electric transmission interconnection projects. NorthWestern agreed to the proposed MCC rate base adjustment. Regarding the pension and benefit reserves, NorthWestern also agreed with the proposed MCC rate base adjustment.

88. NorthWestern did not agree with several other ADIT adjustments. First, NorthWestern addressed accrued property taxes. NorthWestern argued that there is a one-year lag that occurs between the accrual of the expenditures recorded for regulatory and book purposes and the timing of the deduction for those expenditures for tax purposes. Reb. Test. Bjorkman 11–12. Contrary to MCC's argument, NorthWestern asserted it is appropriate to continue to include the associated ADIT as a rate base adjustment.

89. The second adjustment NorthWestern disagreed with was an adjustment to accrued incentive compensation. NorthWestern disagreed with the proposed MCC adjustment. MCC proposed to remove ADIT for accrued incentive compensation. Test Smith 36–37. MCC stated that if ADIT is included in rate base for these items, the associated liability should also be in the rate base. *Id.* at 37. NorthWestern opposed MCC's proposed disallowance of incentive compensation expenses. Reb. Test. Bjorkman 11. NorthWestern argued the timing of the incentive compensation deductions for regulatory and book purposes is different than the timing of the deductions for income tax purposes. *Id.* NorthWestern asserted incentive compensation deductions are immediately deductible for regulatory and book purposes when such costs are incurred. *Id.* For income tax purposes, NorthWestern states, these costs are not deductible until they are paid. *Id.* According to NorthWestern, this results in a perpetual one-year lag of recovery that

occurs every year on those incentive compensation accruals since NorthWestern asserted it does not get a related tax deduction until the following year. *Id.* NorthWestern stated the matching of deductions for tax is different than for regulatory recovery. Thus, NorthWestern argued it is appropriate to continue to include the ADIT as a rate base adjustment.

90. Concerning the environmental reserve balance in ADIT, NorthWestern conceptually agreed to MCC's position but altered the balances found in MCC's proposal. Reb. Test. Bjorkman 14–15. NorthWestern stated MCC proposed to retain ADIT for environmental remediation but also bring in the underlying environmental reserve as a reduction of rate base because of consistency and matching principles. *Id.* at 14. NorthWestern agreed conceptually to this approach and also proposed to bring the environmental reserve balance into the rate base. *Id.* at 14–15. NorthWestern changed the balances from those in MCC's proposal because the Commission ruled that portions of the environmental reserve balance related to the Montana Power Company acquisition were not recoverable from customers.

ii. Settlement Agreement

91. The Settling Parties accepted the tax portion of the electric and natural gas revenue requirements as proposed in Aaron J. Bjorkman's direct and rebuttal testimony. Settlement Agreement ¶ 5.

iii. Discussion and Findings

92. Regarding the operating income tax issues raised by the intervenors, the payroll tax issue was resolved by NorthWestern agreeing with MCC's position in rebuttal. With respect to the other three operating income issues (income tax repairs deduction, income tax meters deduction, and research tax credit) in rebuttal NorthWestern revised its adjustments to closely mirror the adjustments proposed by MCC and LCG. For the repairs and meter deduction, NorthWestern used 2022 actual deductions in revising its revenue requirements. For the research tax credit,

NorthWestern used the four-year average of actual research credits for the years 2018–2021. The Commission finds the arguments of NorthWestern persuasive and finds the revised rebuttal adjustments reasonable. The Commission approves NorthWestern’s rebuttal adjustments for the operating income tax adjustments.

93. Certain rate base impacting ADIT related tax issues were raised by MCC. Regarding the deferred revenue and pension and benefit reserve ADIT related issues, in rebuttal testimony NorthWestern acquiesced to the proposed MCC adjustments. With respect to the environmental reserve ADIT issue, in rebuttal testimony NorthWestern stated it agreed conceptually to MCC’s adjustments but changed the balances from MCC’s proposal. With regards to the accrued incentive compensation and accrued property tax ADIT related issues, in rebuttal NorthWestern stated it did not agree with MCC. The Commission finds that the rebuttal positions of NorthWestern on the environmental reserve, incentive compensation, and property tax ADIT related issues persuasive and finds the corresponding adjustments reasonable. The Commission approves NorthWestern’s rebuttal adjustments to the rate base related ADIT issues.

94. In light of the Commission’s findings and approval of the operating income tax and rate base ADIT adjustments in NorthWestern’s rebuttal, the Commission finds paragraph 5 of the Settlement Agreement reasonable.

E. Jurisdictional Allocation of Transmission and Generation Costs

i. Parties’ Positions

95. NorthWestern’s transmission system and some of its generating plants serve both wholesale and retail customers with each customer category paying a share of the costs. Historically, the share of total costs borne by retail customers has been determined by crediting NorthWestern’s test year transmission and generation revenue requirements by the test year normalized revenue from wholesale customers. *See In re NorthWestern Energy’s Appl. to Increase Nat. Gas & Elec. Rates*, Dkt. D2007.7.8, Order 6852f (July 8, 2008); *In re NorthWestern Energy’s*

Appl. to Increase Nat. Gas & Elec. Rates, Dkt. D2009.9.129 (D2007.7.82), Order 7046h (Dec. 9, 2010); *In re NorthWestern Energy's Appl. to Increase Elec. Rates*, Dkt. 2018.02.012, Order 7604u (Dec. 20, 2019). However, in Docket 2018.02.012, the Commission ordered NorthWestern to prepare and submit a jurisdictional cost of service study in its next rate case for the transmission function “so that parties and the Commission can evaluate the reasonableness of revenue crediting compared to alternatives.” *In re NorthWestern Energy's Appl. to Increase Elec. Rates*, Dkt. 2018.02.012, Order 7604v ¶¶ 119, 128 (May 20, 2020).

96. NorthWestern testified that its electric ECOS in this case is a jurisdictional cost study that allocated transmission costs of service between wholesale and retail jurisdictional customers. *See* Test. Paul M. Normand (ACOS) 19 (Aug. 8, 2022). The jurisdictional cost study resulted in an allocation of \$58.6 million of NorthWestern’s transmission revenue requirement to FERC jurisdictional wholesale customers. Test. Normand (ACOS), Ex. PMN-5 at 2. The cost study did not separately allocate the costs of generation plants that provide wholesale ancillary services. Instead, NorthWestern relied on a wholesale ancillary service revenue credit to offset generation revenue requirements. *See* Test. Mike Cashell 28 (Aug. 8, 2022).

97. NorthWestern proposed to continue the wholesale revenue crediting approach for transmission cost allocation using a three-year average of actual wholesale revenues as the normalized test year credit, which it stated was consistent with past practice. Test. Cashell 23. NorthWestern testified that because its wholesale rates are based on an annual formula rate process, the wholesale revenue credit reflects current information on the use of transmission services by wholesale customers and the costs of providing those services. NorthWestern further contended that the crediting approach was simple and understandable. *Id.* at 24. The crediting approach based on revenue from 2019 through 2021 resulted in an allocation of \$65.9 million of transmission and generation revenue requirements to FERC jurisdictional customers, which NorthWestern stated generally aligns with the results of the jurisdictional cost study. Test. Cashell 24, 28 (\$3.7 million credit

for ancillary services and \$62.2 million credit for transmission revenue).

98. While accepting the revenue crediting approach, LCG opposed NorthWestern's credit calculation. Test. Higgins 12–13. LCG argued that NorthWestern's calculations were convoluted, impossible to follow, and contained errors. *Id.* In addition, LCG contended that the three-year average unreasonably understated the credit because the formula rate process adjusts wholesale rates annually to reflect increasing costs and current use. *Id.* at 13. LCG also argued that it is inconsistent to use a three-year average for the credit when the transmission rate base and expense calculations underlying the revenue requirement are based on a 2021 test year, with known and measurable changes for 2022. *Id.* LCG recommended a credit of \$85.7 million based on actual 2021 wholesale transmission and generation-related ancillary service revenues. *Id.* at 14.

99. MCC supported using the jurisdictional cost study to apportion transmission and generation revenue requirements between retail and wholesale customers. Test. David E. Dismukes 8 (Dec. 19, 2022). However, MCC testified that the cost study was flawed because it allocated 100% of generation plant costs to retail customers. *Id.* at 95. MCC stated that NorthWestern should have estimated regulating reserve requirements as part of its cost study to appropriately allocate generation costs between retail and wholesale customers. *Id.* MCC modified NorthWestern's cost study to reflect a previous Commission decision regarding the allocation of Dave Gates Generating Station ("DGGS") costs based on its provision of wholesale ancillary services. *Id.* at 98. With that modification, MCC concluded that the FERC jurisdictional revenue requirement net of ancillary service revenues was \$65.5. *Id.*, Ex. DED-8.

100. MCC argued that if the Commission decides to continue using the revenue crediting approach, the credit should reflect 2021 actual wholesale revenues. Test. Dismukes 98. MCC objected to a three-year average of wholesale revenues because the relevant costs underlying NorthWestern's proposed revenue requirement were based on 2021 test year amounts, not three-year averages. *Id.* at 98–99. MCC argued a three-year average revenue credit created a

mismatch between revenues and corresponding expenses. *Id.* MCC calculated an alternative wholesale transmission revenue credit of \$79.4 million based on actual 2021 revenues. *Id.* at 99.

101. In rebuttal, NorthWestern opposed LCG's credit based on 2021 revenues. Reb. Test. Glenda Gibson 8 (Mar. 6, 2023). NorthWestern argued that LCG merely selected the largest revenue figure of the three-year period as the credit. *Id.* NorthWestern contended that the 2021 revenue figure was not an accurate reflection of final revenues because a subsequent true-up and refund of an over-collection would occur through the annual formula rate process. *Id.* at 9. NorthWestern stated that the three-year average normalized fluctuations from that process by smoothing out the year-to-year effects of refunds and surcharges and, therefore, was more appropriate than using any single year. *Id.* at 8. NorthWestern disagreed that its calculations were convoluted, impossible to follow, and contained errors. *Id.* at 9–10. Although it admitted in discovery that it made an error in its original revenue requirement, the error affected the calculation of the revenue adjustment, not the calculation of the three-year average. *Id.* NorthWestern maintained the three-year average calculation was straightforward. *Id.*

102. NorthWestern also opposed MCC's modification to the jurisdictional cost study. Reb. Test. Gibson 2. NorthWestern argued the modification was inconsistent with how FERC-jurisdictional ancillary service rates are designed and how NorthWestern currently operates generating plants to provide ancillary services. *Id.* at 4. NorthWestern stated that its wholesale rates for ancillary services reflect the fixed costs of generating units that are capable of and most likely to provide ancillary services. *Id.* Those units currently include Colstrip Unit 4, Basin Creek, and certain hydro facilities in addition to DGGS. *Id.* at 5. NorthWestern testified that the allocation of DGGS costs used in 2012 no longer reflects the current use of the plant as demonstrated by the allocation used in recent cases, including Dockets 2018.12.012 and 2019.11.089. *Id.* NorthWestern also testified that the modification by MCC appeared to assign a portion of the costs for the Spion Kop and Two Dot Wind plants to wholesale customers, although those plants are

dedicated to retail customers. *Id.* at 3. NorthWestern maintained that a credit based on a three-year average reasonably reflects the current cost of providing ancillary services to wholesale customers. *Id.* at 5.

103. NorthWestern opposed MCC's alternative wholesale revenue credit for many of the same reasons it opposed LCG's credit. Reb. Test. Gibson 6. NorthWestern contended MCC selected the largest revenue figure from the three years of wholesale revenues. *Id.* NorthWestern stated that its wholesale rates were based, in part, on a projected test year, with a true-up and refund or surcharge of any over- or under-collection in the following year. *Id.* NorthWestern testified that 2021 revenues included an unanticipated increase in short-term transmission revenue, which resulted in an over-collection and a true-up and refund to wholesale customers in 2022. *Id.* at 7. NorthWestern asserted that using 2021 revenue alone overstated the revenue credit because a portion of that revenue was being refunded. *Id.* at 8. Similarly, NorthWestern objected to MCC's removal of FERC-ordered refunds from the three-year average, asserting it overstated the true revenues and gave retail customers credit for revenues that NorthWestern ultimately would not receive. *Id.* at 7.

104. NorthWestern updated its revenue credit calculation in rebuttal. The updated three-year average wholesale transmission and generation revenue increased to \$73.0 million based on the period 2020 through 2022. Reb. Test. Rich, Ex EAR-3 at 43.² According to NorthWestern, the updated figure reflected the first three full years of actual revenue under the annual formula rate process. Reb. Test. Gibson 10.

ii. Discussion and Findings

105. Historically, the Commission has used a wholesale revenue crediting approach to allocate transmission service revenue requirements between wholesale and retail customers. More recently, the Commission has applied the same approach to generation revenue requirements to account for the provision of

² The 3-year average FERC jurisdictional revenue is comprised of \$69,312,928 in transmission revenue and \$3,705,819 in ancillary services revenue.

ancillary services. This case differs from recent cases in two ways. First, before this case, the wholesale revenues used in the revenue crediting approach were based on rates established in and fixed between periodic FERC rate proceedings. Now, however, NorthWestern has implemented a FERC-approved formula rate process that adjusts wholesale rates annually using updated cost and demand information. Test. Cashell 24. Second, in this case NorthWestern's allocated cost of service study determines separate costs of service for the wholesale and retail customer categories. *See* Test. Normand (ACOS) 19. That analysis, which implements a Commission directive from NorthWestern's last electric rate case (*see* Test. Cashell 2), is intended to allow the Commission and parties to evaluate the reasonableness of the revenue crediting approach compared to alternatives. In other words, continuation of the revenue crediting approach depends, at least in part, on how reasonably it approximates an allocation based on costs of service.

106. Record evidence indicates that each annual revenue figure for the 2020 through 2022 period was affected by the factors NorthWestern described. Revenue in 2020 was affected by a FERC-ordered refund of revenue collected under rates that were approved on an interim basis during the FERC rate proceeding that resulted in the formula rate process. *Reb. Test. Elaine Rich, Ex EAR-3 at 43.* Revenue in 2021 was affected by a short-term increase in demand for transmission service, resulting in an over-collection that, under the formula rate process, was subsequently refunded in 2022. *Id.* In addition, 2022 revenue reflected a change in the cost basis of rates compared to 2021 revenue as well as the 2021 test period on which the retail revenue requirement in this case is based.

107. The revenue crediting approach is a short-cut that simplifies the Commission's retail ratemaking process. Rather than evaluating a full jurisdictional cost of service analysis in every case, wholesale revenue approximates the results of such an analysis. In this case, NorthWestern's jurisdictional cost of service analysis of the transmission revenue requirement is uncontested, except to the extent MCC contested NorthWestern's failure to conduct a jurisdictional cost analysis of generation revenue requirements and modified NorthWestern's study

using allocation factors the Commission previously used to allocate the costs of DGGS. Test. Dismukes 95–98. None of the other parties addressed the study.

108. In rebuttal, NorthWestern provided evidence that the operation of DGGS has changed since the Commission initially adopted the 80% retail – 20% wholesale allocation factors MCC used to modify NorthWestern’s cost study. Reb. Test. Joseph Stimatz 13 (Mar. 6, 2023). Further, the Commission recently used a revenue crediting approach to allocate generation revenue requirements in Dockets 2018.02.012 and 2019.11.089. Reb. Test. Gibson 3.

109. The Commission agrees with MCC that a comprehensive jurisdictional cost study of all relevant cost functions should be used to evaluate the reasonableness of revenue crediting to determine wholesale customer allocations. For purposes of evaluating the reasonableness of the Settlement Agreement, the Commission finds that NorthWestern’s jurisdictional cost of service study is incomplete because it excludes an assessment of ancillary service requirements and a cost-based allocation of generation costs to the provision of wholesale services. The Commission also finds that MCC’s modified cost study relies on an outdated allocation scheme once used for DGGS, which according to record evidence, no longer reflects how NorthWestern uses the facility. Reb. Test. Stimatz 13. Ultimately, the Commission finds that because the record lacks results from a complete and accurate jurisdictional cost study, the historical revenue crediting approach should be used in this case. Due to the effect of the formula rate process on the annual revenue figures, the Commission finds that the credit should not be based solely on 2021 revenue. NorthWestern’s three-year average, while not perfect, strikes a reasonable balance between the interests. Therefore, in evaluating the Settlement Agreement, the Commission finds reasonable an allocation of transmission service costs to wholesale customers based on the average of 2020 through 2022 wholesale revenue of \$69.3 million for transmission and \$3.7 million for generation-related ancillary services.

F. Incentive Compensation Expenses

i. Parties' Positions

110. Northwestern included incentive compensation expenses related to its Annual Incentive Plan (“AIP”) of \$7,558,478 and \$2,783,637, respectively, in its electric and natural gas revenue requirement proposals. Data Resp. MCC-088 (Oct. 7, 2022). NorthWestern identified several objectives for the AIP: aligning the interest of shareholders, customers, and employees; creating incentives for employees to achieve financial and operating results; rewarding employees and teams through compensation consistent with financial operating performance. *Id.*; *see also* Test. Ralph Smith 56–57.

111. MCC asserted that the portion of the AIP for non-union employees related to the financial (i.e., net income) objective should be borne by shareholders, not customers. Test. Smith 58. MCC stated that if financial goals are set properly, achieving the necessary performance should be self-supporting. *Id.* at 59. According to MCC, measures that achieve cost savings, improve sales, or otherwise improve financial results should provide the income necessary to fund performance awards. *Id.* MCC stated that incentive payouts for financial goals can be distinguished from other incentive compensation and asserted that incentives to improve financial performance are not necessarily consistent with customer interests. *Id.* Therefore, MCC proposed to reduce NorthWestern’s proposed electric revenue requirement by \$4,270,736 and the proposed natural gas revenue requirement by \$1,572,208.

112. LCG acknowledged it is reasonable to include expenses for employee incentive plans if the amounts are not excessive and compensation is tied to goals such as customer satisfaction, operating efficiency, and safety. Test. Higgins 20. LCG stated that incentives for financial performance should be funded by shareholders because they, not customers, are the primary beneficiaries of superior financial performance. *Id.* According to LCG, 61.5% of the funding of the 2021 AIP was based on the Company’s financial performance. *Id.* Therefore, LCG proposed to reduce the amount of annual incentive compensation expense included in NorthWestern’s revenue requirement proposal by 61.5%. *Id.* That adjustment reduced the electric revenue requirement by \$4,660,932 and the gas revenue

requirement by \$1,717,072. *Id.* at 9–10, 21.

113. In rebuttal, NorthWestern argued that the adjustments proposed by MCC and LCG were unreasonable. Reb. Test. Crystal Lail 22 (Mar. 6, 2023). NorthWestern claimed that the Commission has historically allowed the recovery of cash awards for good reasons. *Id.* NorthWestern asserted that cash incentives were a key element of total market-based compensation and were critical to attracting, motivating, and retaining a skilled, high-performing workforce. *Id.* at 26–29.

114. NorthWestern disputed as unsupported and shortsighted the argument that good financial performance only benefits shareholders. Reb. Test. Lail 22–23. According to NorthWestern, a financially healthy utility can acquire lower-cost debt and shoulder financial risk, allowing it to fund on-going operations and investments critical to preserving high standards of service, safety, and reliability. *Id.* at 23. Those factors translate into cost savings that are reflected in future rates that are lower and more stable. *Id.* at 27. Therefore, NorthWestern concluded that customers benefit from employee cash awards tied to financial performance and that component of incentive compensation expense should be included in the revenue requirement. *Id.* at 29–30.

115. Finally, NorthWestern argued that the adjustments proposed by MCC and LCG could lead to higher base salaries in lieu of variable incentive compensation to ensure competitive total compensation packages. Reb. Test. Lail 25. NorthWestern contended that result would not benefit customers because incentive programs are designed to encourage proactive pursuit of greater efficiency, safety, reliability, and customer service. *Id.*

ii. Discussion and Findings

116. MCC and LCG offer plausible arguments that incentive compensation expenses designed to enhance financial performance should not be borne by customers. While corporate goals based on safety, reliability, and customer satisfaction are aligned with customers' interests, corporate financial goals primarily benefit shareholders and may not benefit customers to the same extent, or

at all. Test. Smith 58–59; Test. Higgins 20. On the other hand, NorthWestern made plausible arguments that, over time, customers may benefit from more attractive financing available to a financially healthy utility and may experience relatively improved service reliability and safety. Reb. Test. Lail 22–23. It is also plausible that an opportunity for cash incentives as part of a market-based compensation package is necessary to attract, motivate, and retain a skilled, high-performance workforce that benefits customers. Reb. Test. Lail 25–29. For purposes of evaluating the Settlement Agreement, the Commission finds that a reasonable incentive compensation expense ranges from \$3,092,645 and \$1,138,998 for the electric and gas utilities, respectively, on the low end to \$7,558,478 and \$2,783,637 for the electric and natural gas utilities, respectively, on the high end. The low end represents an average of MCC and LCG’s proposals and the high end represents NorthWestern’s proposal.

G. Stock-Based Compensation for Non-Executives

i. Parties’ Positions

117. NorthWestern included in its proposed revenue requirement stock-based compensation expense for non-executives of \$503,228 and \$184,517 for its electric and natural gas revenue requirements, respectively. Data Resp. MCC-245(d) (Nov. 16, 2022).

118. MCC contended that customers should not be required to pay executive or management compensation that is based on the performance of NorthWestern’s stock price or primarily benefits NorthWestern’s shareholders.³ Test. Smith 64. MCC asserted that for ratemaking purposes, the provision of stock-based compensation should be treated as a dilution of shareholder’s investments, i.e., as a cost borne by shareholders who elect the directors that approve stock-based compensation. *Id.* at 67. MCC’s adjustment reduced the electric revenue

³ NorthWestern withdrew its request to include stock-based compensation for executive employees in rates. *See* Test. Ralph Smith 63.

requirement by \$503,228. Test. Ralph Smith, Ex. RCS-1, Schedule A at 4. MCC's adjustment reduced the natural gas revenue requirement by \$185,052. *Id.* at Ex. RCS-2, Schedule A at 4.

119. LCG asserted that it is appropriate for shareholders to bear the cost of long-term equity awards since the purpose of such awards is to align the interests of executives and shareholders. Test. Higgins 22. According to LCG, NorthWestern reported in its 2022 proxy statement that it "[does] not recover equity incentive awards in our rates approved by our regulators." *Id.* LCG proposed an adjustment to remove all non-executive long-term equity awards from the revenue requirements. *Id.* LCG's adjustment reduced the electric revenue requirement by \$540,569 and the gas revenue requirement by \$198,209. Test. Higgins, Exs. KCH-6, KCH-16.

ii. Discussion and Findings

120. The Commission finds the positions of MCC and LCG persuasive. NorthWestern's proposal conflicts with its own 2022 proxy statement. Test. Higgins 22. Consistent with NorthWestern's representations, it should not recover stock-based compensation expenses in its Commission-approved rates. For purposes of evaluating the Settlement Agreement, the Commission finds that NorthWestern's proposed revenue requirements should be reduced by \$540,569 and \$198,208 for the electric and natural gas utilities, respectively.

H. Stock-Based Compensation for the Board of Directors

i. Parties' Positions

121. MCC advocated that as stock owners, the directors are in the same position and have similar incentives as NorthWestern's common stockholders. MCC recommended removing the board of directors' stock-based compensation from NorthWestern's revenue requirements for the same reason stock-based compensation for non-executive employees should be excluded. Test. Smith 67. That adjustment decreases the electric and natural gas revenue requirements by

\$378,349 and \$138,728, respectively. Test. Smith, Ex. RCS-1, Schedule A at 4; Ex. RCS-2, Schedule A at 4.

122. LCG argued the primary duty of the board of directors is to represent shareholders' interests; therefore, it is not appropriate to include stock-based compensation to directors in rates. Test. Higgins 22–23. LCG removed stock-based compensation expenses for the board of directors from the revenue requirements. *Id.* The adjustment amounts LCG proposed are the same as those proposed by MCC. Test. Higgins, Ex. KCH-17.

123. In rebuttal, NorthWestern opposed MCC and LCG's adjustments. NorthWestern argued that stock-based incentives are a common component of total compensation for directors and officers. Reb. Test. Lail 28. NorthWestern contended that good stock price performance is generally an indication of a well-run, financially healthy utility, and any cost savings, including a lower cost of capital, should accrue to customers through future rate reviews. *Id.* at 29–30. NorthWestern asserted that good governance and stock price performance are goals that a utility should strive for, and as such, the costs to support these goals should be recoverable in rates. *Id.* at 30.

ii. Discussion and Findings

124. The Commission finds the positions of MCC and LCG persuasive. The primary duty of the board of directors is to represent shareholders' interests. The directors are in the same position and have similar incentives as common stockholders. For purposes of evaluating the Settlement Agreement, the Commission reduces NorthWestern's proposed revenue requirements by \$378,349 and \$138,728 for the electric and gas utilities, respectively.

I. Natural Gas Production Asset Revenue Requirement Step-Down

i. Parties' Positions

125. Natural gas production assets "deplete" rather than "depreciate." Test.

Bleu LaFave 18 (Aug. 8, 2022). Natural gas wells produce greater volumes with higher well pressures. *Id.* Well pressures are highest at the beginning of their production lives and are reduced over time as the natural gas is withdrawn. *Id.* Therefore, wells produce a higher percentage of their reserves at a higher rate in the beginning and produce less at a slower rate as they age. *Id.*

126. In NorthWestern’s 2016 natural gas general rate review, the Commission addressed the cost recovery of natural gas production assets. Test. LaFave 20. Ultimately, the Commission approved a revenue requirement with a percentage step-down each year. *Id.* The production asset revenue requirement step-down captures the decreasing production of NorthWestern’s gas-producing assets over time due to depletion by reducing the revenue requirements on an annual basis. *See id.* at 20–22.

127. NorthWestern testified that the step-down the Commission adopted in Order 7522g, Docket D2016.9.68, which estimated an annual reduction to the production revenue requirement to account for anticipated reductions in annual depletion expense, remains appropriate. Test. Durkin 46. However, NorthWestern proposed to update the estimated revenue requirement reductions to reflect: (1) the current level of non-depleted natural gas reserves; (2) the estimate of annual natural gas production volumes; (3) the estimated amount of future asset retirement obligations associated with the production facilities; and (4) other necessary changes to the overall natural gas production cost of service. *Id.* NorthWestern revised the annual step-down in rebuttal testimony to reflect the rebuttal revisions to the natural gas production revenue requirement. Reb. Test. Rich 39. The proposed step-down is presented in the following table.

Production Revenue Requirement			
Stepdown Rich Rebuttal Exh. EAR-7			
	Percentage	Production	Dollar
Year	Reduction	Rev. Req.	Reduction
2022		\$22,009,353	
2023	-3.40%	\$21,262,095	(\$747,258)
2024	-3.30%	\$20,560,224	(\$701,871)
2025	-3.13%	\$19,916,280	(\$643,944)
2026	-3.17%	\$19,285,432	(\$630,848)
2027	-3.01%	\$18,705,235	(\$580,197)
2028	-2.70%	\$18,200,328	(\$504,907)
2029	-2.94%	\$17,664,886	(\$535,442)
2030	-2.86%	\$17,159,078	(\$505,808)
2031	-2.79%	\$16,680,754	(\$478,324)
2032	-2.71%	\$16,228,246	(\$452,508)
Total 10 Year Reduction			(\$5,781,107)

128. During the hearing, NorthWestern acknowledged that the 2022 production revenue requirement has been reduced from the amount NorthWestern proposed in rebuttal by approximately \$276,000, or from \$22,009,353 to the stipulated production revenue requirement of \$21,733,174. Hr’g Tr. 1439:19–25; 1440:19–25; 1441:1–15. NorthWestern further acknowledged that for 2023 the stipulated production revenue requirement should be reduced by 3.4% to reflect the 2023 step-down. *Id.* at 1442:10–20. The table below revises the production asset revenue requirement step-down so that 2022 reflects the stipulated production asset revenue requirement and the resulting 2023 stepped down revenue requirement.

Production Revenue Requirement			
Stipulation Ex. B. Rev. Requirement			
	Percentage	Production	Dollar
Year	Reduction	Rev. Req.	Reduction
2022		\$21,733,174	
2023	-3.40%	\$20,994,246	(\$738,928)
2024	-3.30%	\$20,301,436	(\$692,810)
2025	-3.13%	\$19,666,001	(\$635,435)
2026	-3.17%	\$19,042,589	(\$623,412)
2027	-3.01%	\$18,469,407	(\$573,182)
2028	-2.70%	\$17,970,733	(\$498,674)
2029	-2.94%	\$17,442,393	(\$528,340)
2030	-2.86%	\$16,943,541	(\$498,852)
2031	-2.79%	\$16,470,816	(\$472,725)
2032	-2.71%	\$16,024,457	(\$446,359)
Total 10 Year Reduction			(\$5,708,717)

ii. Discussion and Findings

129. None of the intervenors contested continuation of the annual step-down of the production asset revenue requirement. Therefore, the Commission finds that it is reasonable to continue the step-down approach, as adopted in Order 7680g. For purposes of evaluating the Settlement Agreement, the Commission will rely on the 2023 production asset revenue requirement of \$20,994,246.

J. Settlement Analysis: Electric Revenue Requirement

130. The Settling Parties agreed to increase the electric base revenue requirement by \$67,377,467 plus property taxes of \$14,529,164, for a total increase of \$81,906,631. Settlement Agreement ¶ 1. This results in a total electric service revenue requirement excluding property taxes of \$501,986,925 and a base property tax revenue requirement of \$126,840,181 for a total revenue requirement of \$628,827,106. *Id.* The Settling Parties further agreed to a 9.65% ROE on electric service rate base, excluding Colstrip Unit 4. *Id.* ¶ 3.

131. The Commission's analysis of the record indicates that an increase to NorthWestern's electric revenue requirement of \$71.3 million represents the low-

end of a range of reasonableness. The low-end of the range of reasonableness reflects the Commission's findings above regarding adjustments for depreciation, incentive compensation expenses, stock-based compensation for non-executives, stock-based compensation for members of the board of directors, and the low-end ROE of 9.19%.

132. The Commission's analysis indicates that an increase of \$90.6 million represents the high-end of a range of reasonableness. The high-end increase reflects the Commission's findings regarding stock-based compensation for members of the board of directors and stock-based compensation for non-executives. The high-end revenue requirement reflects an ROE of 9.78%.

133. Based on this analysis, the Commission finds that the stipulated revenue requirement of \$81,906,631 million is reasonable because it falls between the low-end increase of \$71.3 million and high-end increase of \$90.6 million. Further, the Commission finds that the stipulated ROE of 9.65% is reasonable because it falls between the low-end ROE of 9.19% and the high-end ROE of 9.78% and satisfies the fair return standard. The Commission finds that the stipulated electric revenue requirement is fair and will result in just and reasonable rates.

K. Settlement Analysis: Gas Revenue Requirement

134. The Settling Parties agreed to increase the natural gas base revenue requirement by \$14,060,425 and property taxes by \$4,150,562 for a total increase of \$18,210,987, resulting in a natural gas base rate revenue requirement of \$130,075,062 and a base property tax revenue requirement of \$38,181,601 for a total revenue requirement of \$168,256,663. Settlement Agreement ¶ 2. The Settling Parties further agreed to a 9.55% ROE on natural gas service rate base. *Id.* ¶ 3.

135. The Commission finds that an increase to NorthWestern's gas revenue requirement of \$15.8 million represents the low-end of a range of reasonableness. The low end reflects MCC's adjustments for depreciation and incentive compensation expenses; the Commission's findings regarding stock-based compensation for non-executives, stock-based compensation for members of the

board of directors; and a production asset revenue requirement based on the step-down approach for 2023. The low-end revenue requirement reflects an ROE of 9.19%.

136. The Commission finds an increase to NorthWestern's revenue requirement of \$23.1 million represents the high-end of a range of reasonableness. The high-end of the range of reasonableness includes the Commission's findings regarding stock-based compensation for members of the board of directors and stock-based compensation for non-executives, and the production asset revenue requirement step-down. The high-end revenue requirement reflects an ROE of 9.78%.

137. The Commission finds that the stipulated natural gas revenue requirement is fair and will result in just and reasonable rates. The total increase of \$18,210,987 falls within the reasonable range determined through the Commission's analysis. Additionally, the stipulated 9.55% ROE for natural gas service assets falls within the reasonable range of ROEs and satisfies the fair return standard. The Commission finds that the stipulated natural gas revenue requirements are fair and will result in just and reasonable rates. As discussed above, the Commission also finds that an adjustment to the natural gas revenue requirement is necessary to reflect the production asset step-down for 2023. When implementing final rates from this Order, NorthWestern must use the 2023 stepped-down revenue requirement of \$20,994,246. This reduces the approved 2022 total natural gas revenue requirement by \$738,928 from \$168,256,663 to \$167,517,735. Thereafter, beginning on January 1 of each ensuing year, Northwestern must reduce rates for the production asset revenue requirement by the amounts shown in the table in ¶ XXX until the issue is revisited in a future general rate case.

II. Cost Allocation and Rate Design

A. Electric Embedded Cost of Service

i. Parties' Positions

138. Paul M. Normand, a Principal at Management Applications Consulting, Inc., conducted marginal and embedded cost studies for NorthWestern. Test. Normand (ACOS) 1; Appl. Stmt. L (providing details of marginal cost of service studies (“MCOSS”) and ECOSS studies). NorthWestern allocated the cost of production plant according to monthly generation in 2021, based on the proportion of each customer class’s monthly sales adjusted for losses. Test. Normand (ACOS) 12. NorthWestern allocated transmission costs using a simple average of class contributions to the utility’s monthly one-hour system coincident peak. *Id.* at 13. For distribution costs, NorthWestern allocated costs to customer classes based on the class’s load contribution to customer class peaks after eliminating higher voltage classes not served by the distribution system. *Id.* NorthWestern allocated primary distribution costs based on the higher class demand contribution to the class peaks after eliminating substation and higher voltage loads not served by these facilities. *Id.* NorthWestern allocated secondary distribution costs based on the primary class demands less primary and higher voltage customer demands. *Id.* at 14.

139. NorthWestern allocated the cost of meters and services based on the typical metering cost per customer, including installation for each rate class. Reb. Test. Paul M. Normand 19 (Mar. 6, 2023). NorthWestern stated that this estimate was multiplied by the number of assigned meters in each class, which resulted in a total cost estimate by customer class. *Id.* This estimate was employed to assign actual meter costs. *Id.* NorthWestern allocated service costs based on an estimated service cost per customer multiplied by the number of estimated services per customer class. *Id.* at 15. NorthWestern allocated customer service costs using an average factor weighted 75% to customer numbers and 25% to sales. *Id.* at 16.

140. MCC testified that NorthWestern’s revenue allocation proposals appeared to be a fair representation of the relative costs associated with providing service to each of the utility’s electric customer classes. Test. Dismukes 90. MCC recommended the Commission accept NorthWestern’s electric ECOSS. *Id.*

141. LCG opposed NorthWestern’s proposal to allocate generation plant

based solely on class energy usage, asserting that the approach is inconsistent with cost causation and extremely unusual. Test. Justin Bieber 12 (Dec. 19, 2022). LCG was unaware of any other state-regulated, investor-owned utility that allocates generation plant entirely based on energy. *Id.* LCG contended that allocation of generation plant costs generally accounts for the capability of generation plant to provide capacity to meet system peak demands. *Id.* LCG also asserted that “the methods commonly used for allocating generation plant costs incorporate some metric for measuring class demand requirements.” *Id.*

142. LCG stated that allocating generation plant costs exclusively based on energy ignores customer class peak demands. Test. Bieber 14. LCG argued that while NorthWestern may have historically allocated generation plant costs exclusively based on energy usage, that approach is particularly inappropriate now given Montana’s evolving energy landscape and the utility’s increasing need for capacity resources to provide reliable electric supply for its customers. *Id.*

143. LCG asserted that either the class 12 coincident peak (“12 CP”) or Average and Excess (“A&E”) demand methods would be appropriate for allocating NorthWestern’s generation plant costs. Test. Bieber 15, 17. LCG recommended using the 12 CP allocation method because it would align with cost causation and would be consistent with NorthWestern’s allocation of transmission plant. *Id.* at 15, 17. LCG contended that allocating generation plant “using a demand-based allocator would better align with cost causation and properly consider the fact that NorthWestern’s owned generation plant provides a significant capacity contribution that helps [the utility] provide reliable electric supply to its customers during periods of peak demand.” *Id.* at 17.

144. LCG argued transmission plant costs are properly classified as 100% demand related. Test. Bieber 19. Given NorthWestern’s load characteristics, the 12 CP approach that the utility used to allocate transmission plant was reasonable and appropriate. *Id.* at 19.

145. LCG stated the approach used by NorthWestern for allocating substation plant costs, meter costs, and customer service costs is generally

reasonable. Test. Bieber 19. LCG contended, however, that the utility's distribution ECOSS method allocated the cost of poles, conductors, and transformers exclusively on class demand, without considering that the cost of those facilities also has a significant customer-related component. *Id.* LCG stated these facilities are "installed to provide customers access to the utility's system regardless of peak consumption." *Id.* LCG argued that classifying these distribution facilities as 100% demand-related does not recognize that both the peak demand and number of customers interconnected to the system drive the need for more investment in poles, wires, and other distribution infrastructure. *Id.* at 19–20.

146. LCG asserted NorthWestern's analysis "under-assigns cost responsibility based on the number of customers served and over-assigns cost responsibility based on demand, unreasonably shifting costs to the larger customers served on the primary and secondary distribution system." Test. Bieber 20. LCG recommended that "the Commission require the utility to perform either a minimum-size or zero-intercept study in its next general rate case filing." *Id.* at 21. LCG stated it was not recommending adjustments to the allocation of distribution costs but recommended that "this over-allocation of distribution plant to larger customers should be considered in the context of electric class revenue allocation." *Id.*

147. LCG also recommended changes to NorthWestern's allocation of customer services expenses. Test. Bieber 22. LCG stated that NorthWestern has allocated customer service expenses on a 75% customer/25% energy basis and that "[t]hese expenses are directly related to providing widespread information and assistance to customers, regardless of their usage characteristics." *Id.* LCG contended there was no rationale for assigning these expenses based on class energy usage and that the proper allocation of these expenses was on a 100% customer basis. *Id.*

148. LCG prepared a revised ECOSS, presented in Exhibit JB-2, which used the 12 CP method to allocate NorthWestern-owned generation plant and non-fuel generation operations and maintenance expenses. Test. Bieber 9, 22, Ex. JB-2.

LCG's analysis also used a 100% customer allocator to allocate customer service expenses and did not adjust NorthWestern's transmission or distribution plant allocation. Test. Bieber 22.

149. FEA's expert witness asserted NorthWestern's allocation of production-related plant costs entirely on the basis of class energy was not typical and does not reflect class cost causation. Test. Brian C. Collins 7 (Dec. 19, 2022). FEA argued that an allocation of production plant costs based on energy fails to consider that generating capacity was acquired to meet the peak demand. *Id.* FEA contended that "[m]ethods such as the coincident peak method and the A&E method better reflect class causation and recognize that generation capacity is installed to meet the peak demands of customers that are placed on the [utility's] system." *Id.*

150. FEA recommended that NorthWestern's next rate review should include an ECOSS scenario that includes the allocation of production plant costs based on the A&E demand method. Test. Collins at 9. FEA contended that this would improve the utility's ECOSS in terms of class cost causation. *Id.*

151. In rebuttal, NorthWestern contended that its owned electric supply resources represent slightly over 60% of its total capability, with a "very large portion of these capabilities being renewable resources of solar, wind, and hydro facilities." Reb. Test. Normand 5. NorthWestern asserted that a "large portion" of its resource capabilities comes from hydro generation facilities, which are "basically hourly energy resources." *Id.* NorthWestern stated its class allocation was the same as proposed in its last electric rate case, using monthly generation synchronized with matching monthly class sales adjusted for losses. *Id.*; see *In re NorthWestern Energy's Appl. to Increase Elec. Rates*, Dkt. 2018.02.012, Order 7604u at 49–54 (Dec. 20, 2019). NorthWestern stated that its proposal to allocate the costs of the utility's distribution facilities on the basis of contributions to class peak demands of customers served from the distribution system was consistent with NorthWestern's previous electric rate review. Reb. Test. Normand 6.

152. NorthWestern rejected the recommendations of LCG to require either a minimum-system or zero-intercept analysis to modify the distribution allocation,

raising issues with the availability of cost data and the potential for significant customer impacts. Reb. Test. Normand 7–9. NorthWestern also rejected LCG’s recommendation of a 100% customer allocation basis for customer service expenses, arguing this allocation resulted in large users being allocated a minuscule cost assignment. *Id.* at 10. NorthWestern contends its proposal of a 75% customer/25% sales allocation basis is consistent with the prior electric rate review. *Id.*

153. MCC filed cross-intervenor testimony opposing LCG’s proposal to require NorthWestern to file a minimum-size or zero-intercept study, contending that the approaches are fundamentally flawed and would provide little to no value in the determination of just and reasonable rates. Cross-Intervenor Test. David E. Dismukes 12 (Mar. 6, 2023). MCC also recommended the Commission reject LCG’s proposal to classify customer service expenses as 100% customer related. *Id.* at 16. MCC asserted LCG’s proposal was unsupported, and that classifying a part of these costs as energy-related was appropriate because it included activities designed to promote customer electricity conservation. *Id.* at 13–16.

154. MCC recommended the Commission reject the proposals by LCG and FEA for classifying generation plant assets, arguing the parties have not proven that NorthWestern’s ECOSSE generation plant classification contains a significant error or inaccuracy. Cross-Intervenor Test. Dismukes 25.

155. LCG filed cross-intervenor testimony opposing MCC’s recommendation to accept NorthWestern’s ECOSSE, contending the utility’s decision to allocate production costs entirely on the basis of energy is inconsistent with cost causation and extremely unusual. Cross-Intervenor Test. Justin Bieber 3–4 (Mar. 6, 2023).

ii. Discussion and Findings

156. Generally, the Commission finds that NorthWestern and the intervening parties discussed above used standard methods to functionalize and classify NorthWestern’s embedded costs of service. As discussed in the following section, the parties’ proposals for allocating revenue requirements were influenced by their proposals for moderating the rate impacts for certain classes to adhere to

principles of gradualism and equity. In addition, the parties' cost of service-based class revenue allocations are based on NorthWestern's initial revenue requirement and parties had differing views on how reductions to that revenue requirement should influence considerations of moderation and gradualism in the revenue allocations. For these reasons, the Commission finds that it is neither necessary nor helpful to attempt to quantify a zone of reasonableness with regard to class costs of service. Instead, as described below, the Commission evaluates the Settlement Agreement on a qualitative basis using the parties' cost of service study results and moderated class revenue recommendations as a guide.

B. Electric Allocation of Revenue Requirement

i. Parties' Positions

157. NorthWestern proposed moderated class cost allocations and rate designs. At the system level, NorthWestern proposed to increase total electric rates by 21.1%, exclusive of property taxes. *See Test. Cynthia Fang (ACOS & Rate Design) 15, 29–30 (Aug. 8, 2022)*. The electric ECOSSE provided the basis for NorthWestern's proposed class cost allocations. *Id.* at 14. NorthWestern proposed to moderate the ECOSSE results due to concerns about the rate impacts that would occur if electric costs were allocated purely on a cost basis. *Id.* at 16.

158. NorthWestern proposed to cap the increases for any customer class at no more than 24% and set a floor of no less than 15%. *Test. Fang (ACOS & Rate Design) 16*. NorthWestern explained that the cost-based allocation for the Irrigation class was 24.3% and that it did not apply the cap to Irrigation given the small difference. *Id.* n. 3. NorthWestern stated that its moderation proposals were applied at the total base revenue requirement level. *Id.* at 16.

159. MCC stated that, in general, NorthWestern's proposed revenue allocations represented a fair allocation of revenues across customer classes. *Test. Dismukes 112*. MCC noted that NorthWestern's proposed rate caps and rate floors were fixed in nature, with a maximum rate increase of 23.5% and a minimum rate increase of 9.9%. *Id.* MCC asserted these boundaries may be appropriate in the

context of the utility's proposed overall rate increase of 21.1%, but these boundaries would change if the overall allowed revenue requirement differs. *Id.* MCC recommended that the Commission limit the rate increase for any single rate class to 1.25 times the overall system average increase and apply a minimum rate increase to any single rate class equal to 0.53 times the overall system average increase. *Id.* at 112–13. MCC contended that this cap and floor mirror the utility's proposed 23.5% rate cap and 9.9% rate floor relative to its proposed system average increase of 21.1%. *Id.* at 113.

160. LCG agreed that NorthWestern's proposed maximum rate increase of 24%, applied to class revenue requirements exclusive of property tax revenues, was reasonable at NorthWestern's proposed revenue requirement. Test. Bieber 35. LCG asserted that NorthWestern's application of a minimum rate increase was unnecessary and resulted in significant cost shifting from customer classes that do not require rate mitigation further from the cost of service. *Id.*

161. LCG argued NorthWestern's implementation of its proposed minimum rate increase is inconsistent across customer classes and exacerbates subsidies required to implement the proposed minimum rate increase. Test. Bieber 37. LCG contended that after NorthWestern applied the minimum rate increase to the GS-1 Primary and GS-2 Transmission rate classes, the utility arbitrarily introduced other subsidies into the rate moderation process. *Id.* LCG maintained that the resulting impacts between rate classes that do not require rate mitigation were highly inequitable. *Id.*

162. LCG argued that based on NorthWestern's allocated cost of service, the GS-1 Primary class would deserve a 1.1% rate increase, while the GS-2 Transmission class would deserve a 12.8% decrease. Test. Bieber 37. Yet, under NorthWestern's proposal, both rate classes would receive a rate increase of 20.5%, exclusive of property taxes, which is more than 5.5% greater than the proposed minimum rate increase. *See id.* LCG also asserted the GS-1 Secondary rate class deserved a cost-based rate increase of 14.6%, but would receive a 17.9% increase, exclusive of property taxes. *Id.*

163. LCG recommended that the Commission accept NorthWestern’s proposed 24% maximum rate increase, at NorthWestern’s proposed revenue requirement, to be applied to class revenues exclusive of property taxes. Test. Bieber 37. LCG asserted that the subsidies to mitigate the rate impacts for customer classes that would otherwise receive a rate increase greater than 24% should be funded by the remaining rate classes on an equal percentage basis, relative to class revenues at current rates. *Id.* at 37–38. LCG contended that “[i]f providing funding for rate moderation cause[d] a customer class’s rate increase to exceed the maximum rate increase, then the maximum rate increase may need to be applied a second time to ensure that no class exceeded the rate cap.” *Id.* at 38.

164. LCG also recommended that the Commission reject any minimum rate increase for rate moderation purposes. Test. Bieber 38. LCG asserted a minimum rate increase was unnecessary and moved classes further away from the cost of service. *Id.* LCG contended that NorthWestern’s implementation of a minimum rate increase included arbitrary adjustments that further distorted the alignment between class revenue allocation and cost causation and resulted in inequitable cost shifting between rate classes that do not require rate moderation. *Id.*

165. FEA asserted NorthWestern’s class revenue allocation proposal should be rejected. Test. Collins 9. FEA argued that an approach that moves class revenue requirements significantly closer to cost-based rates should be approved instead. *Id.* at 9–10. FEA contended that despite the results of its ECOSS, NorthWestern’s class revenue allocation proposal resulted in excessive increases in rates for certain customer classes that were not cost-based. *Id.* at 10.

166. FEA asserted NorthWestern’s class revenue allocation was improper and should be rejected because it did not provide a significant movement to cost-based rates for all classes. Test. Collins 12. FEA proposed an alternative to the utility’s proposal that moved class revenue requirements closer to cost of service. *Id.* FEA stated that though it disagreed with the production allocators used in NorthWestern’s ECOSS, it based its class revenue allocation proposal on the results of the study. *Id.*

167. FEA argued NorthWestern's proposed revenue allocation resulted in subsidies. Test. Collins 12. It stated that under NorthWestern's ECOSSE, the GS-2 Transmission class should see a rate decrease of 68.21%, but the utility's proposed class revenue allocation increased GS-2 Transmission class rates by 15.99%. *Id.* FEA contended this proposed increase moved the GS-2 class significantly further away from cost of service. *Id.*

168. FEA asserted its class revenue allocation proposal moved classes closer to cost of service, while recognizing the principle of gradualism by limiting any one customer class to no greater than 1.5 times the system average increase. Test. Collins 13. FEA's class revenue allocation used its corrected ECOSSE results. Test. Collins, Ex. BCC-1.

169. FEA noted that the FEA-proposed class revenue allocation used NorthWestern's full requested revenue requirement. Test. Collins 13. FEA asserted that if the Commission reduces the utility's requested revenue increase, FEA's proposed class revenue allocation should be adjusted accordingly. *Id.*

170. Walmart's expert witness advocated for setting rates based on the utility's cost of service for each customer class and producing equitable rates that reflect cost causation, send proper price signals, and minimize price distortions. Test. Andrew D. Teague 5 (Dec. 19, 2022). Walmart did not oppose NorthWestern's proposed revenue allocation at the proposed revenue requirement. *Id.* at 8. Walmart contended that if the Commission approves a revenue requirement lower than that proposed by the utility, the Commission should begin with the revenue allocation proposed by NorthWestern and use the reduction in revenue requirement to move classes closer to cost of service. *Id.*

171. In rebuttal, NorthWestern proposed to narrow the moderation cap to no greater than 23.9% and no less than 17.5%. Reb. Test. Fang (ACOS & Rate Design) 9. NorthWestern asserted "[t]he percentages maintain a range based on no greater than 113.8 times the system average increase and no less than 71.1 times the system average increase." *Id.*

172. MCC filed cross-intervenor testimony opposing FEA's proposal to limit

the increase for any customer class to no more than 1.5 times the system average increase. Cross-Intervenor Test. Dismukes 26. MCC argued under FEA's proposed revenue allocation, residential customers would receive 25.2% rate increases, while GS-2 transmission service customers would receive a 9.2% rate decrease. *Id.*

173. LCG filed cross-intervenor testimony opposing MCC's recommendation of a minimum rate increase. Cross-Intervenor Test. Bieber 5. LCG also disagreed with Walmart that NorthWestern's proposed electric revenue allocation should be used as the starting point to determine revenue allocation between rate classes at a different revenue requirement. *Id.* at 6. In response to both parties, LCG contended the utility's proposed maximum increase was reasonable but argued that the application of a minimum rate increase was unnecessary and resulted in significant cost shifting that moved certain customer classes, which do not require rate mitigation, further from the cost of service. *Id.* at 5–7. LCG maintained that if the Commission approved a lower revenue requirement, it should take advantage of the reduction in the requested revenue requirement to move classes closer to the cost of service. *Id.* at 7.

174. LCG stated that FEA's alternative revenue allocation method limiting the rate increase to 1.5 times the system average was a reasonable alternative to LCG's proposal. *Id.* at 8. LCG asserted FEA's proposal included a maximum rate increase cap relatively close to the maximum rate increase proposed by NorthWestern and did not include a minimum rate increase. *Id.*

ii. Settlement Agreement

175. The Settlement Agreement adopts specific electric class revenue allocations:

The updated total base revenue requirement including property taxes that reflects the overall base revenue increase of \$81,906,632 for electric service shall be allocated to NorthWestern's customer classes through adjustments in base revenue requirements. Table 1 below presents the Settlement Class Revenue Allocation for electric customers based on

total revenue defined as property tax and base revenues and excludes Power Costs and Credit Adjustment Mechanism (“PCCAM”) revenues.

Settlement Agreement ¶ 8.

Revenue Allocation by Customer Class of Total Electric Revenues*				
	Current	Settlement		
	Total	Total		
Customer Class	Revenues	Settlement Revenues	Increase	% Increase
Residential	243,656,855	288,002,402	44,345,548	18.20%
GS-1 Secondary	236,111,829	268,164,308	32,052,480	13.58%
GS-1 Primary	22,631,442	22,631,442	-	0.00%
GS-2 Substation	14,670,941	17,341,052	2,670,111	18.20%
GS-2 Transmission	6,633,988	6,633,988	-	0.00%
Irrigation	9,634,131	10,245,302	611,170	6.34%
Lighting	13,581,290	15,808,612	2,227,322	16.40%
Total Electric Revenues	546,920,475	628,827,106	81,906,631	14.98%
*Total Electric Revenues include Property Tax and Base Revenues and excludes PCCAM Revenues				
Source: Table 1: Settlement Agreement				

iii. Discussion and Findings

176. The Settlement Agreement allocates the increased electric revenue requirement across NorthWestern’s customer classes in a manner that moves closer to the cost-causer, cost-payer principle, but not entirely. The electric increase is allocated across a variety of customer classes ranging from a zero percent increase for the GS-1 Primary and GS-2 Transmission classes to a 6.34% increase for Irrigation, a 16.4% increase for Lighting, and a 18.2% increase for GS-2 Substation. In an effort to bring their rates closer to costs, the Residential and GS-1 Secondary customer classes receive increases of 18.2% and 13.6%, respectively.

177. The Commission accepts as reasonable the electric revenue customer class allocations in the Settlement Agreement. Based on the parties’ cost of service results and moderated class revenue allocations, and given the mix of interests represented among the Settling Parties, the Commission finds that the Settlement

Agreement's class revenue allocations represent a just and reasonable compromise that satisfies the public interest.

C. Electric Rate Design

i. Parties' Positions

178. NorthWestern's ECOSS provided the foundation for its rate design proposal. Test. Fang (ACOS & Rate Design) 14 (Aug. 8, 2022). NorthWestern proposed limited changes to rate design for its electric service customers, including an increase to monthly service charge for all non-residential customers, with the exclusion of non-demand customers on Secondary GS-1. *Id.* at 21. NorthWestern contended this increase would move towards more cost-based pricing of electric services. *Id.* NorthWestern asserted that all its electric monthly service charges were below cost-based levels and that an increase in the monthly service charge would result in a compensating decrease in all other charges to ensure the rates developed were revenue neutral. *Id.* at 22-23.

179. For Residential and GS-1 Secondary Non-Demand customers, NorthWestern proposed no change to its current monthly service charge. *Id.* at 24. For customer groups with a fixed charge that is currently more than 50% of cost-based levels, NorthWestern proposed to increase the monthly service charge to cost-based levels. *Id.* This included the GS-1 Primary Non-Demand, GS-2 Transmission, and Irrigation Non-Demand customer groups. *Id.* For customer groups with a monthly service charge that was below 50% of cost-based, NorthWestern proposed to double the monthly service charge. *Id.* This would include the GS-1 Primary Demand, GS-2 Substation, and Irrigation Non-Demand customer groups. *Id.* at 24–25. NorthWestern contended that for these customer groups, even after the increase, the proposed monthly service charge would remain below cost-based levels. *Id.* at 24.

180. LCG supported NorthWestern's proposed electric rate design methodology for the non-residential rate schedules. Test. Bieber 54. LCG stated the rate design would make gradual movement towards aligning rates with the

underlying cost causation while maintaining the existing rate structure and employing a reasonable level of gradualism to avoid potentially significant intra-class rate impacts. *Id.*

181. LCG asserted that if the Commission approves a different revenue allocation or revenue requirement, then NorthWestern's proposed electric rate design methodology for the general service rate schedules should be applied to determine the final base electric service rates. Test. Bieber 54.

182. Walmart did not oppose NorthWestern's proposed GS-1 charges to move GS-1 closer to cost-based levels. Test. Teague 10.

183. In rebuttal, NorthWestern changed the rounding of customer charges. Reb. Test. Fang (ACOS & Rate Design) 16, Table 15.

ii. Settlement Agreement

184. The electric rate design is addressed in Exhibit C of the Settlement Agreement. Under the Settlement Agreement, only the GS-2 Substation class receives an increase in its monthly services charges, moving the customer class closer to cost of service-based levels. Other customer classes receive increases to energy and/or demand charges.

iii. Discussion and Findings

185. The Commission accepts as reasonable the electric rate design as proposed by the Settling Parties in Exhibit C of the Settlement Agreement. The proposed rate design is minimal and only the GS-2 Substation customers receive an increase. No party challenged NorthWestern's proposed changes to the monthly service charges for non-residential customers.

D. Natural Gas Embedded Cost of Service

i. Parties' Positions

186. NorthWestern classified and allocated Distribution Mains and Transmission Pipeline costs on the basis of customer class design day demands.

Test. Normand 57. NorthWestern classified all of its meters and services costs as customer costs, which then are allocated based on customer counts. *Id.* at 58.

NorthWestern classified and allocated its Administration and General (“A&G”) costs primarily based on labor or labor-related expenses. *Id.*

187. MCC proposed an alternative natural gas ECOSS that classified and allocated NorthWestern’s Distribution Mains and Transmission Pipeline costs based on 50% firm customer class design day demands and 50% firm customer class annual dekatherm (“Dkt”) volumes. Test. George Donkin 21 (Dec. 19, 2022).

188. MCC classified 50% of meters and services costs as customer costs, and 50% as capacity-related costs, which were allocated on the basis of customer class design day demands. *Id.* at 24. MCC argued that NorthWestern’s customer class meter installation costs increase significantly with the level of customer class annual per customer deliveries. *Id.* at 23. MCC contended this relationship supported classifying and allocating a portion of NorthWestern’s meter costs as capacity-related costs. *Id.* MCC also argued the same conclusion is valid with respect to NorthWestern’s service costs. *Id.* (citing Data Resp. MCC-161 (Oct. 21, 2022))

189. MCC classified and allocated 36.4% of NorthWestern’s total Distribution, Transmission, and Storage A&G expenses based on annual Dkt customer class quantities, and 63.6% on the basis of NorthWestern’s salaries and wages allocator. Test. Donkin at 25.

190. LCG agreed with NorthWestern’s allocation of transmission plant based on class design day demands. Test. Bieber 25. LCG agreed that distribution demand-related costs were appropriately allocated based on design day demands but disagreed that all distribution infrastructure is demand-related. *Id.* LCG argued that a substantial portion of the distribution mains infrastructure is caused by the need to physically interconnect customers to the system, and thus are driven by the number of customers on the system. *Id.* at 25–26. LCG contended NorthWestern’s allocation of distribution plant costs entirely on a demand basis did not properly recognize that a significant portion of distribution plant costs were

driven by the number of customers on the system. *Id.* at 26.

191. LCG argued the proposed classification of natural gas delivery distribution plant as entirely demand related ignored the role of the number of customers and their geographic dispersion in influencing system investment requirements. Test. Bieber 26–27. LCG contended the utility’s analysis under-assigned cost responsibility based on the number of customers served and over-assigned cost responsibility based on demand, shifting costs inappropriately to the larger customer classes. *Id.* at 27.

192. LCG stated it is not recommending an adjustment to the natural gas ECOSS but pointed out that the approach used by NorthWestern resulted in an over-allocation of distribution plant costs to larger customer classes, such as DBU Transportation. Test. Bieber 27. For informational purposes, LCG recalculated the natural gas ECOSS results to demonstrate how the results would be impacted if 25% of distribution plant costs were allocated on a customer basis. *Id.* LCG did not recommend an adjustment to the allocation of distribution costs in the ECOSS, but asserted the over-allocation of distribution plant to larger customers should be considered in the context of the natural gas class revenue allocation. *Id.* at 27–28.

193. LCG agreed with NorthWestern’s treatment of interruptible customers. Test. Bieber 29. LCG stated that given that interruptible customers’ loads can be curtailed, if necessary, NorthWestern did not consider interruptible loads for its capacity planning. *Id.* LCG also stated NorthWestern’s proposal to increase the volumetric charge for interruptible customers by the same percentage increase that is assigned to the corresponding firm transportation class, ensured that interruptible customers would continue to pay a portion of the system’s fixed costs consistent with the current rate structure. *Id.*

194. In rebuttal, NorthWestern disputed MCC’s assertion that large portions of transmission and distribution costs are related to a commodity function. Reb. Test. Normand 24. NorthWestern maintained that class contributions to design day loads should be used to allocate transmission and distribution investment. *Id.* at 24–25. NorthWestern opposed MCC’s approach to the allocation

of service and meter costs, contending the utility undertook specific analyses to develop allocation factors for services that reflected the specific costs of those services for each customer within classes and between classes of customers. *Id.* at 25. NorthWestern also opposed LCG's proposal for allocating investment costs, arguing customer counts have little to do with larger main sizes. *Id.* at 18.

195. LCG filed cross-intervenor testimony opposing MCC's proposed modifications to NorthWestern's natural gas ECOSS, arguing the modifications are not aligned with cost causation and would further exacerbate cost shifting by not classifying any portion of distribution costs as customer-related. Cross-Intervenor Test. Bieber 14.

ii. Discussion and Findings

196. For reasons described above under the Electric Embedded Cost of Service section, the Commission does not quantify a zone of reasonableness for the natural gas embedded costs of service. The Commission, again, qualitatively accounts for the parties' cost of service study results and moderation approaches in evaluating the merits of the Settlement Agreement.

E. Allocation of Natural Gas Revenue Requirement

i. Parties' Positions

197. NorthWestern used the same class allocation approach for the natural gas revenue requirement as it did for the electric revenue requirement. Test. Fang (ACOS & Rate Design) 17. At the system level, natural gas cost of service increased by over 16%. *Id.* at 18. As with the electric revenue allocation, NorthWestern proposed to moderate impacts across its natural gas customers to more equitably spread the increase in cost of service across customer groups. *Id.* Specifically, NorthWestern proposed to cap the increase for any customer class at no more than 19%. *Id.* NorthWestern asserted this resulted in a narrow range of impacts to natural gas customers of approximately 7%, from 11.8% to 19%. *Id.* at 18–19. Consistent with the electric revenue allocation, NorthWestern's moderation

proposals were applied to the total base revenue requirement. *Id.* at 19.

198. MCC proposed alternative customer class revenue targets for NorthWestern's proposed total natural gas revenue increase. Test. Donkin, Exhibit GLD-3. According to MCC, at present rates the Residential, General Service, and Firm Storage customer classes are producing RORs that are above NorthWestern's total Montana system average ROR and, therefore, these customer classes should be assigned lower percentage increases in revenues than the Total Montana revenue increase. Test. Donkin 30. MCC proposed percentage increases of 13.60%, 13.55%, and 13% for Residential, General Service, and Firm Storage, respectively. *Id.* at 32.

199. MCC contended at present rates the Employee, Firm Utilities, Firm DBU Transport, and Firm TBU Transport customer classes should be assigned higher percentage increases in revenues than the total Montana revenue increase. *Id.* at 30. MCC proposes class percentage increases as follows: 25% for Employee, 19.5% for Utilities, 22.5% for DBU Firm Transportation, 22.5% for TB Firm Transportation, 22.5% for DBU Interruptible Transportation, and 25% for TBU Interruptible Transportation. *Id.* at 32.

200. LCG agreed that NorthWestern's proposed maximum rate increase of 19%, applied to class revenue requirements, exclusive of property tax revenues, was reasonable at NorthWestern's proposed revenue requirement. Test. Bieber 49. LCG did not recommend any changes to NorthWestern's proposed gas revenue allocation at the proposed revenue requirement. *Id.* LCG stated that if the Commission approves a natural gas revenue requirement that is less than NorthWestern's request, NorthWestern's proposed revenue allocation should be used to establish each rate schedule's percentage share of the final base rate revenue requirement. *Id.*

201. Walmart did not oppose NorthWestern's proposed natural gas revenue allocation. Test. Teague 22. Walmart asserted that if the Commission approves a revenue requirement lower than that proposed by the utility, the Commission should use the reduction in revenue requirement to move classes closer to cost of

service. *Id.*

202. In rebuttal, NorthWestern provided updated proposed revenue allocations to correct for changes to the natural gas current revenues and the percentage change from current revenues stated in NorthWestern's direct testimony. Reb. Test. Fang (ACOS & Rate Design) 4. NorthWestern stated that the corrections did not affect the requested revenue requirement or the cost-based allocation of the revenue requirement but impacted the results of its moderation proposal. *Id.*

203. NorthWestern asserted that because the system average increase was actually 21.1%, not 16.8% as stated in direct testimony, NorthWestern updated the cap on the increase to natural gas customer classes to 23.9% instead of 19%. Reb. Test. Fang (ACOS & Rate Design) 6. NorthWestern contended this modification maintained the cap at 113.3 times the system average increase as proposed in direct testimony. *Id.*

204. NorthWestern proposed moderation to class revenue allocations that narrowed the range of impacts to natural gas customer classes to no greater than 21.6% and no less than 18.6%. Reb. Test. Fang (ACOS & Rate Design) 10.

205. LCG filed cross-intervenor testimony disagreeing with the results of MCC's modified ECOSS but stating that the revenue allocation presented in MCC's exhibits are within the zone of reasonableness. Cross-Intervenor Test. Bieber 23–24. LCG continued to recommend its natural gas revenue allocation methodology but contended that MCC's proposal is not significantly different. *Id.* at 24.

ii. Settlement Agreement

206. The natural gas revenue allocation is addressed in paragraph ten and Table 2 of the Settlement Agreement.

The updated base revenue requirement including property taxes that reflected the overall revenue increase of \$18,210,987 for natural gas serve shall be allocated to NorthWestern's customer classes through adjustment in base revenue requirements. Table 2 below presents the

Settlement Class Revenue Allocation for natural gas customers based on total revenues defined as property tax and base revenues.

Table 2: Settlement Agreement Natural Gas Revenue Allocation					
Revenue Allocation by Customer Class of TotalNatural Gas Revenues					
		Current	Settlement		
		Total	Total		
Customer Class		Revenues	Settlement Revenues	Increase	% Increase
Residential		83,246,960	93,078,528	\$9,831,568	11.8%
Residential Employee		135,459	155,532	\$20,073	14.8%
General Service		44,116,244	49,253,706	\$5,137,462	11.6%
Utilities		503,137	577,693	\$74,556	14.8%
DBU Firm Transportation		2,593,875	2,975,451	\$381,576	14.7%
TBU Firm Transportation		13,924,622	15,988,007	\$2,063,385	14.8%
Storage		3,605,652	4,023,601	\$417,949	11.6%
DBU Interruptible Transportation		49,244	56,488	\$7,244	14.7%
TBU Interruptible Transportation		1,870,483	2,147,656	\$277,173	14.8%
Stipulated Revenue Requirement Increase - MT Natural Gas Tariff		150,045,676	168,256,662	18,210,986	12.1%
*Total Electric Revenues include Property Tax and Base Revenues					

iii. Discussion and Findings

207. The natural gas increase is also allocated across a variety of customer classes. The Residential Employee, Utilities, DBU Firm Transportation, TBU Firm Transportation, the DBU Interruptible Transportation, and TBU Interruptible Transportation all receive an approximately 14% increase. The Residential General Service, and Storage customer classes all receive an increase of approximately 11%.

208. The Commission accepts as reasonable the natural gas customer class allocation as proposed by the Settling Parties in Table 2 of the Settlement Agreement. However, the \$18,210,987 gas revenue requirement is the stipulated 2022 revenue requirement. When final rates are implemented pursuant to this Order, the revenue requirement to be recovered by those rates must reflect the 2023 Production Asset Revenue Requirement Stepdown of \$738,928. Table 2 of the Settlement Agreement spread the natural gas revenue requirement increase to the customer classes using the following percentages:

Customer Class	Percent of Increase
Residential	53.99%
Residential Employee	0.11%
General Service	28.21%
Utilities	0.41%
DBU Firm Transportation	2.10%
TBU Firm Transportation	11.33%
Storage	2.30%
DBU Interruptible Transportation	0.04%
TBU Interruptible Transportation	1.52%
Stipulated Revenue Requirement Increase - MT Natural Gas Tariff	100.00%

209. Using those same percentages and the revised Natural Gas revenue requirement yields the following customer class revenue allocation.

Table 2: Settlement Agreement Natural Gas Revenue Allocation Including 2023 Production Revenue Requirement Stepdown (\$738,928)				
Revenue Allocation by Customer Class of Total Natural Gas Revenues				
Customer Class	Current Total Revenues	Settlement Total Settlement Revenues	Increase	% Increase
Residential	83,246,960	92,679,603	\$ 9,432,643	11.3%
Residential Employee	135,459	155,532	\$ 19,259	14.2%
General Service	44,116,244	49,253,706	\$ 4,929,005	11.2%
Utilities	503,137	577,693	\$ 71,531	14.2%
DBU Firm Transportation	2,593,875	2,975,451	\$ 366,093	14.1%
TBU Firm Transportation	13,924,622	15,988,007	\$ 1,979,661	14.2%
Storage	3,605,652	4,023,601	\$ 400,990	11.1%
DBU Interruptible Transportation	49,244	56,488	\$ 6,950	14.1%
TBU Interruptible Transportation	1,870,483	2,147,656	\$ 265,926	14.2%
			\$ -	
Stipulated Revenue Requirement Increase - MT Natural Gas Tariff	150,045,676	167,857,737	\$ 17,472,059	11.6%
*Total Electric Revenues include Property Tax and Base Revenues				

F. Natural Gas Rate Design

i. Parties' Positions

210. As with the electric rate design, NorthWestern's natural gas rate design proposal began with the cost-based rate design developed by Paul Normand. Test. Fang (ACOS & Rate Design) 21. NorthWestern then reviewed the difference between the structure of current rates and cost-based rates to determine the need for changes. *Id.*

211. NorthWestern asserted it had also limited changes to rate design proposals for its natural gas service customers and proposed only to increase the monthly service charge to all non-residential customers to move towards more cost-based pricing of natural gas service. Test. Fang (ACOS & Rate Design) 22. The utility contended that all of NorthWestern's natural gas monthly service charges were below cost-based levels and that an increase in the monthly service charge would result in a compensating decrease in all other charges to ensure the rates developed were revenue neutral. *Id.* at 26.

212. For residential customers, NorthWestern proposed no change to the current monthly service charge. Test. Fang (ACOS & Rate Design) 27. For customer groups with a fixed charge that is currently more than 50% of cost-based levels, NorthWestern proposed to increase the monthly service charge to cost-based levels. *Id.* This would include the General Service, Utilities, and DBU Firm Transportation customer groups. *Id.*

213. For customer groups with a monthly service charge that is currently below 50% of cost-based, NorthWestern proposed to double the monthly service charge. Test. Fang (ACOS & Rate Design) 27. This would apply to the TBU Firm Transportation customers. *Id.* at 27–28. NorthWestern contended that for this customer group, even after the increase, the proposed monthly service charge would continue to remain below cost-based levels. *Id.*

214. MCC agreed with NorthWestern's proposal to keep residential and employee service charges at their current levels of \$6.50 per month (residential) and \$4.88 per month (employee). Test. Donkin 33.

215. LCG supported NorthWestern's proposed gas rate design methodology for the non-residential rate schedules because it would make gradual movement

towards aligning rates with the underlying cost causation while maintaining the existing rate structure and employing a reasonable level of gradualism to avoid potentially significant intra-class rate impacts. Test. Bieber 55. LCG asserted if the Commission approves a different revenue allocation or revenue requirement, then NorthWestern's proposed gas rate design methodology for the non-residential rate schedules should be applied to determine the final base natural gas service rates. *Id.*

216. Walmart did not oppose the Company's proposed general natural gas service charges. Test. Teague 25.

217. The only changes proposed by NorthWestern in rebuttal were rounding of customer charges and minor changes in natural gas general service customer charges due to corrections to customer counts. Reb. Test. Fang (ACOS & Rate Design) 15, 17.

ii. Settlement Agreement

218. The natural gas rate design is addressed in paragraph 11 and Exhibit D of the Settlement Agreement. The Settling Parties accept the proposed natural gas monthly service charges as set forth in the testimony of Cynthia S. Fang. Settlement Agreement ¶ 11.

iii. Discussion and Findings

219. The Commission accepts as reasonable the natural gas rate design as proposed by the Settling Parties in paragraph 11 of the Settlement Agreement. Under the proposed rate design, residential customers will see no change to their current monthly service charge, and no party challenged NorthWestern's proposed changes to the monthly service charges for non-residential customers.

III. Riders

A. Power Costs and Credits Adjustment Mechanism

i. Parties' Positions

220. NorthWestern recovers certain power supply costs and differences between base power supply revenue and actual costs through its PCCAM. Test. Stimatz 3. Power supply costs and credits covered by the mechanism include wholesale market energy purchases and sales, capacity purchases, and purchases from qualifying facilities (“QFs”). *Id.* at 3. Except for purchases from QFs, the difference between base power supply revenue and actual costs is subject to a 90/10 sharing mechanism wherein NorthWestern recovers 90% of its actual costs that exceed base revenues and refunds 90% of base revenues that exceed actual costs. *In re Comm’n’s Rev. Rates to Recover NorthWestern’s Elec. Supply Costs*, Dkt. D2017.5.39, Order No. 7563c ¶ 69 (Nov. 29, 2018). DSM and PSC and MCC funding fees are also recovered through the PCCAM. Test. Stimatz 3–4.

221. NorthWestern’s current PCCAM base power supply cost of \$138,655,703 was set in 2019. The base power supply cost remains fixed until NorthWestern files a subsequent general rate case. Since the PCCAM base supply costs were set, NorthWestern’s PCCAM actual supply costs have increased and NorthWestern has generally under-collected its PCCAM costs. NorthWestern proposed to update PCCAM base costs to reflect current market and fuel prices and changes in its supply portfolio. Test. Stimatz 16. NorthWestern proposed total PCCAM base costs of \$208,282,098. Reb. Test. Stimatz, Ex. JMS-5 (Mar. 6, 2023).

222. NorthWestern proposed adding interest to the deferred balances (i.e., the difference between actual costs and actual revenues from PCCAM base rates accrued between rate adjustments). Test. Fang (Policy) 33 (Aug. 8, 2022). NorthWestern proposed to apply an interest rate to deferred balances equal to one-twelfth the interest rate on three-month commercial paper for the previous month, as reported in the Federal Reserve Statistical Release, H. 15, or its successor publication. *Id.* at 34–35.

223. NorthWestern proposed to update PCCAM base costs on an annual basis going forward with monthly, rather than annual, rate adjustments for deferred balances. Test. Fang (Policy) 30–31. NorthWestern argued those changes will better align PCCAM rates with the cost of service. *Id.* at 34.

224. NorthWestern proposed to exclude the costs of contracts for capacity from the PCCAM sharing mechanism. Test. Fang (Policy) 31. NorthWestern stated that given its capacity deficit and the fixed-cost nature of capacity resources, any incentives to control costs do not apply. Test. Stimatz 33. NorthWestern proposed to adjust capacity costs in each annual PCCAM filing. Test. Durkin 70.

225. None of the intervening parties contested NorthWestern's proposed PCCAM base power supply cost. MCC stated that it did not oppose NorthWestern's interest rate proposal if the Commission rejected NorthWestern's proposal to implement monthly PCCAM rate adjustments. Data Resp. PSC-063e (Feb. 24, 2023). MCC opposed monthly PCCAM rate adjustments, which it contended would erode the positive effects of regulatory lag and weaken financial incentives to control costs. Test. Dismukes 116–117. MCC recommended denying NorthWestern's proposal to exclude capacity costs from sharing. *Id.* at 75. MCC stated such an exclusion could result in procurement inefficiencies and higher costs for customers. *Id.* at 75.

226. LCG supported interest on deferred balances at the three-month commercial paper rate so long as interest applied symmetrically to under- and over-collections. Test. Higgins 48. LCG opposed monthly PCCAM rate adjustments, asserting that it would cause rate volatility and increase the complexity of the mechanism. *Id.* at 46. LCG proposed retaining the current PCCAM method. *Id.* at 48. LCG opposed excluding capacity purchases sharing mechanism due to concerns about the effect on contracts that include negotiable terms for both capacity and energy. *Id.* at 47.

227. FEA supported adding an interest component to the deferred balance. Test. Greg R. Meyer 29 (Dec. 19, 2022). FEA opposed monthly rate adjustments. *Id.* FEA asserted that NorthWestern already benefits from more timely cost recovery as a result of the PCCAM and changing to monthly rate adjustments would require more resources and complicate the process. *Id.* at 49. FEA opposed NorthWestern's proposal to exclude capacity purchases from sharing and argued NorthWestern should share in any capacity costs that are not included in base costs through a

general rate case. *Id.* at 29. FEA stated NorthWestern could plan its rate case activity around its long-term needs and coordinate its capacity decisions. *Id.* at 30.

228. MEIC supported interest on deferred balances. Test. Karl R. Rabago 39 (Dec. 19, 2022). MEIC argued that updating PCCAM base supply costs annually was reasonable. *Id.* at 41. MEIC asserted that monthly rate adjustments could result in too much rate volatility. *Id.* at 39. MEIC instead proposed interim PCCAM adjustments on a semiannual basis. *Id.* at 39. MEIC supported application of the sharing mechanism to capacity costs because it provides incentives to diligently forecast and plan for the future, and to negotiate aggressively on behalf of customers in procuring capacity contracts. *Id.* at 40.

229. HRC/NRDC/NWEC opposed excluding capacity costs from sharing because it would remove the incentive to minimize costs and increase the risk of unexpectedly high power costs. Test. Amanda Levin 42–45 (Dec. 19, 2022). HRC/NRDC/NWEC testified that excluding capacity costs from the sharing mechanism would insulate NorthWestern from its responsibility to keep capacity costs reasonable and pursue a “holistic,” least-cost approach to managing load in high-cost hours. *Id.* at 44.

ii. Settlement Agreement

230. The Settlement Agreement sets PCCAM base supply costs of \$208,282,098, effective July 1, 2022. Settlement Agreement ¶ 13. That amount matches NorthWestern’s proposed PCCAM base cost. Reb. Test. Stimatz, Ex. JMS-5 (Mar. 6, 2023). The Settlement Agreement also includes interest on deferred balances. Settlement Agreement ¶ 14. During the hearing, NorthWestern clarified on behalf of the parties to the Settlement Agreement that interest would be applied symmetrically to the deferred balance (both positive and negative balances). Hr’g Tr. 250:15–25; 251:1–14.

231. The Settlement Agreement adopts quarterly PCCAM rate adjustments for over- or under-collections to minimize the deferred balance. Settlement Agreement ¶ 14. The Settlement Agreement retains the process of setting PCCAM

base costs in general rate cases, with the exception of a one-time adjustment once the YCGS is in service. *Id.* ¶ 14–15. This one-time adjustment contemplated by the Settlement Agreement is discussed in greater detail later in this Order.

232. The Settlement Agreement does not address the application of the sharing mechanism to capacity costs. During the hearing, NorthWestern testified that because the Settlement Agreement does not specify that capacity costs are excluded from sharing, the sharing mechanism will continue to apply to capacity costs. Hr’g Tr. 205:4–25; 206:1–8.

iii. Discussion and Findings

233. For purposes of evaluating the Settlement Agreement, the Commission finds that NorthWestern’s proposed PCCAM base power supply cost is reasonable. No party offered testimony regarding an alternative to the PCCAM Base Costs. The record shows that the PCCAM base cost of \$138,655,703 approved in Docket 2018.02.012 is insufficient to recover expected costs, which are estimated to be \$220.7 million for the period July 2022 through June 2023. Data Resp. PSC-070 (Mar. 30, 2023). Based on this uncontested evidence, the Commission finds NorthWestern’s proposed PCCAM base of \$208,282,098 to be reasonable.

234. The Commission finds reasonable the symmetrical application of interest on PCCAM deferred balances at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor publication.

235. The amount of under-collected supply costs over the past several years under the PCCAM is concerning. The deferred balance for the period July 2021 through June 2022 was approximately \$52.8 million. The Commission finds that quarterly updates as provided for in the Settlement Agreement will help mitigate the potential for unreasonably large, deferred balances in the future. Accordingly, the Commission finds the quarterly updates provided for in the Settlement Agreement reasonable. The Settlement Agreement maintains the status quo regarding modifications to PCCAM base supply costs and rates. In rebuttal and

through the Settlement Agreement, NorthWestern effectively withdrew its request to adjust PCCAM base costs annually and, therefore, no findings are necessary. *See* Reb. Test. Fang (Policy) 24; Settlement Agreement ¶ 14.

236. The record indicates that as part of the compromise embodied in the Settlement Agreement, the 90/10 PCCAM sharing mechanism will continue to apply to capacity costs. Hr’g Tr. 205:4–25; 206:1–8. Because the sharing mechanism is intended to provide incentives to minimize PCCAM costs and risks, the Commission finds that applying the mechanism to capacity costs is reasonable.

B. One-Time PCCAM Base Adjustment

i. Settlement Agreement

237. In paragraph 15 of the Settlement Agreement, the Settling Parties agreed to a one-time PCCAM base adjustment. The Settlement Agreement set the following parameters for the one-time adjustment:

a. NorthWestern may request a one-time PCCAM Base Costs and property tax base reset to be effective on the date the Yellowstone County Generating Station (“YCGS”) is placed into service;

b. The filing will reflect the inclusion in PCCAM Base Costs of those costs that are normally eligible for PCCAM recovery including gas transmission reservation charges included in FERC Account 547 that are estimated to be \$8.4 million annually;

c. The filing will request a prudence review and a determination by the Commission of whether or not the plant is in the public interest;

d. If YCGS is deemed prudent, capital cost recovery will be addressed in the next general rate case;

e. If NorthWestern makes a filing to modify the PCCAM Base Costs and property tax base, the Settling Parties agree to a temporary modification to the PCCAM tariff to allow for inclusion in PCCAM Base Costs, and subsequent tracking and sharing, operating and maintenance costs, as described and estimated in Exhibit ADD-17; and

f. The modification to the PCCAM to allow for operating and maintenance costs recovery related to YCGS will be limited to the time

period between the date the plant is placed in service and the implementation of new rates following NorthWestern's next general rate case.

Settlement Agreement ¶ 15.

238. The estimated operating and maintenance costs to be included in the one-time PCCAM Base Costs update are as follows: Variable non-fuel O&M expenses of \$1.3 million annually included in FERC Account 553 (maintenance of generating and electric plant); Variable engine maintenance expenses of \$2.3 million annually included in FERC Account 553 (maintenance of generating and electric plant); and Fixed O&M expenses of \$2.7 million annually included in FERC Account 546 (operation, supervision, and engineering) and FERC Account 549 (miscellaneous other power generation expenses). Settlement Agreement ¶ 15.

ii. Discussion and Findings

239. Paragraph 15 is permissive regarding a future PCCAM filing by NorthWestern associated with the completion of the YCGS. The Settling Parties merely agree NorthWestern may request a one-time PCCAM Base Cost and property tax reset. NorthWestern is not required to make such a filing, nor is the outcome of such a filing guaranteed. This provision of paragraph 15 is important since paragraph 14 of the Settlement Agreement states that the Settling Parties agree that the PCCAM Base Costs will not be reset until the next general rate case. Paragraph 15 is an exception to this rule, and it only applies to the procedural arguments that the Settling Parties may make in the potential future filing. It does not bind the Non-Settling Parties.

240. Paragraph 15 states that the filing will request a prudence review and a determination by the Commission of whether the plant is in the public interest. At the hearing, NorthWestern acknowledged that if the Commission requires a prudency process similar to the requirements of a preapproval docket, NorthWestern would comply. Hr'g Tr. 263:10–17. In addition, NorthWestern indicated that nothing in this docket would preclude any party from disputing the

prudence of YCGS. *Id.* at 256:8–25, 257:1–7.

241. Paragraph 15 of the Settlement Agreement reflects an understanding between the Settling Parties, and the Commission accepts it as such. In approving the Settlement Agreement, the Commission does not foreclose any procedural arguments from any other party, including arguments about the propriety of a one-time PCCAM base adjustment outside of a general rate case.

242. If NorthWestern files an application pursuant to paragraph 15 of the Settlement Agreement, the Commission expects a full and extensive prudence review will be conducted. In Docket 2021.02.022, NorthWestern’s Application for Preapproval of Capacity Resources (later withdrawn by NorthWestern) NorthWestern provided testimony and evidence on the following topics:

- a. Regional capacity deficit and the Electric Load Carrying Capability study;
- b. NorthWestern Resource adequacy;
- c. Western Imbalance Market;
- d. Short-term Request for Production (“RFP”);
- e. Effect of YCGS NorthWestern’s supply portfolio;
- f. Effect on NorthWestern’s PCCAM;
- g. Effect on the Revenue Credit NorthWestern’s retail customers receive;
- h. The role of the RFP sponsor;
- i. The RFP process, including how the RFP was structured to address NorthWestern’s need for long-duration capacity;
- j. The RFP selection process;
- k. The contracting process;
- l. Aion’s role as the RFP Administrator and with a thorough description of the RFP process;
- m. The latest Integrated Resource Plan (“IRP”);
- n. The modeling of the economic dispatch performance of proposals and portfolios of proposals submitted in response to the RFP;
- o. The construction and operation of the YCGS;
- p. NorthWestern’s transmission system in relation to our capacity need;

- q. Electric interconnection of resources;
- r. Natural gas transmission for resources;
- s. The required Carbon Offset Plan; and
- t. The revenue requirement including the anticipated return on equity, debt costs, and capital structure for the YCGS and the related rate design and rate impact.

243. At a minimum, NorthWestern must be prepared to address all of the topics listed above, and any other concerns that intervenors may reasonably raise in compliance with Commission rules.

C. Reliability Rider

i. Parties' Positions

244. NorthWestern proposed a reliability rider ("RR") to track and recover costs for critical, new reliability assets between rate reviews on an interim basis starting on the in-service date of the new asset. Test. Fang (Policy) 24. These interim rates would then be subject to an adjustment following a prudence review in a future rate case. *Id.* NorthWestern stated its RR proposal was intended to reduce regulatory lag from Montana's current regulatory structure and make new reliability assets available to serve critical customer needs. *Id.* at 25. NorthWestern intended for the RR to apply to the costs for any investments aimed at improving reliability for electric service customers. *Id.* at 26.

245. NorthWestern asserts that customers would be protected under the RR because recovery for investments made outside a test year would be on an interim basis until a prudence review occurs in the next rate review. *Id.* 26. NorthWestern proposes that such rate reviews would occur no later than three years from the in-service date of the reliability assets.

246. The intervening parties in this docket generally opposed the creation of the RR. Test. Dismukes 113; Test. Higgins 35; Test. Robago 2, 19; Test. Levin 3, 23; Test. Jeff Smith 18 (Dec. 19, 2022); Test. Sashwat Roy 20, 58 (Dec. 19, 2022); Test. Teague 5; Test. Roger Schiffman 13–18 (Dec. 19, 2022). Only Walmart did not

oppose the creation of the RR, but recommended allocating costs on a dollar-per-kilowatt basis. Test. Teague 5. The intervening parties expressed concern regarding the RR being single-issue ratemaking, not satisfying the National Regulatory Research Institute (“NRRI”) criteria for cost tracking recovery and violating the matching principle. Test. Levin 36; Test. Jeff Smith 3; Test. Meyer 15; Test. Higgins 7, 26; Test. Dismukes 23–24, 38–39. Furthermore, the potentially long interim rate period may prove complicated to undo later if the Commission decides the acquisition was not prudent. Test. Schiffman 18. Overall, the parties argued the RR was too broad, lacked support, and would hinder or override the Commission’s ability to oversee, review, and ensure that utility investments are prudent and just and reasonable. Test. Dismukes 17; Test. Higgins 36; Test. Levin 39–40.

247. In rebuttal, NorthWestern proposed to include a contested case process in the RR to address the concerns expressed by parties regarding the adequacy of the regulatory process. Reb. Test. Fang (Policy) 15. That process would involve an application for approval of the acquisition of the resource no more than 180 days after implementation of interim rates. The application would include a comparison of projected and actual costs over the first 12 months of interim recovery. *Id.* at 15–16.

ii. Settlement Agreement

248. The Settling Parties agreed in paragraph 15 of the Settlement Agreement that the RR will not be approved in this proceeding.

iii. Discussion and Findings

249. Through the Settlement Agreement, NorthWestern has withdrawn its request for approval of the RR and, therefore, no findings are necessary on this issue.

D. Wildfire Mitigation Rider

i. Parties’ Positions

250. NorthWestern proposed an Enhanced Wildfire Mitigation Plan (“Wildfire Plan”) rider to address growing wildfire risks. Appl. 2. NorthWestern is currently taking steps to reduce wildfire risk through the Distribution System Infrastructure Plan (“DSIP”), an evolving Hazard Tree Program, and the Vegetation Management Program. Test. Curtis Pohl 12 (Aug. 8, 2022).

251. The original scope of the Hazard Tree Program was to remove hazard trees outside of the rights of way along approximately 1,030 miles of transmission and distribution lines. Test. Pohl 15. The original program cost was estimated at \$18.5 million and started in May of 2018. *Id.* As part of the last electric rate review, Docket 2018.02.012, NorthWestern was allowed approximately \$3.2 million annually in the revenue requirement, which was the actual amount spent in 2018. *Id.* At the end of 2021, NorthWestern had removed approximately 1,207 miles of hazard trees, including the 1,030 miles in the original scope of the program. *Id.* The total cost was \$18.8 million or an average of \$4.7 million per year over the past four years. *Id.* The original Hazard Tree Program has evolved and is now referred to as the Risk Tree Program due to the introduction of additional risk factors. *Id.* at 15–16. The Risk Tree Program works in conjunction with the broader Vegetation Management Program, each providing specific benefits toward reducing known risks. *Id.*

252. The Wildfire Plan rider was designed to capture and coordinate all of NorthWestern’s activities associated with wildfire risk mitigation, while also enhancing and building upon this foundation to increase effectiveness. Test. Pohl 16. According to NorthWestern, the more robust Wildfire Plan rider would result in: acceleration and expansion of system hardening activities; expansion of vegetation management activities beyond the approved Hazard Tree Program; and establishment of programs related to situational awareness and communications and public outreach. Test. Fang (Policy) 19.

253. NorthWestern argued the Wildfire Plan rider would allow the utility to align costs more closely with the benefits received by current customers, as well as offer stability in monthly bills and help customers avoid rate shock. Test. Jennifer

E. Nelson 46 (Aug. 8, 2022). NorthWestern estimated the Wildfire Plan costs to be approximately \$193 million in capital investments and \$95 million in operations and maintenance expenses for 2024 through 2028. Test. Gregory F. Bailly 4 (Aug. 8, 2022).

254. MCC recommended the Commission reject the Wildfire Plan rider because the proposal for recovery did not satisfy NRRI criteria for the creation of a tracker. Test. Dismukes 41. MCC argued the costs were not substantial relative to total costs, were not outside the control of the utility, and were neither volatile nor unpredictable. *Id.* MCC argued NorthWestern's wildfire expenditures were not expected to exceed the Commission's 5% of net income threshold for materiality used in evaluating requests for deferred accounting orders. *Id.* at 40. MCC noted that NorthWestern has indicated that its total wildfire mitigation costs are expected to decrease by \$31.6 million over the next five years under the Wildfire Plan. *Id.* Consequently, MCC argued that the costs intended for recovery under the proposed rider are not so substantial that traditional ratemaking practices cannot be employed. *Id.*

255. MCC further contended NorthWestern has direct control over its spending because the Company has been able to budget a five-year plan. Test. Dismukes 41. MCC also cited the five-year budget as evidence that they were, to an extent, predictable. *Id.* MCC recommended rejecting NorthWestern's Wildfire Plan rider because it failed to satisfy any of the three NRRI-recommended evaluation criteria for the establishment of a tracker. *Id.*

256. LCG did not have a specific objection to the Company's Wildfire Plan but recommended denying a rider to recover the costs. Test. Higgins 27. LCG asserted the Wildfire Plan costs should be recovered through conventional ratemaking. *Id.* LCG stated that the proposed rate design would double-recover the plan's transmission-related costs from choice customers, who are subject to these same costs in their FERC-jurisdictional transmission rates. *Id.* LCG further argued the Wildfire Plan would improperly recover distribution costs from customers taking service at transmission voltage and unreasonably recover distribution and

transmission costs from demand-billed customers through an energy charge rather than through a demand charge. Test. Higgins 27–28.

257. LCG asserted the Wildfire Plan rider is an example of single-issue rate making—it ignores the multitude of other factors that otherwise influence rates, some of which could, if properly considered, move rates in the opposite direction from the single-issue change. Test. Higgins 28. LCG maintains that setting rates based on a single cost item runs contrary to the basic principles of traditional utility regulation. *Id.* LCG contends that rate riders have traditionally been considered when costs are volatile, unpredictable, and beyond the utility’s control, however, the costs of the Wildfire Plan exhibit none of these characteristics. *Id.*

258. Although FEA did not fully support NorthWestern’s regulatory treatment of the Wildfire Plan, FEA acknowledged the greater risk posed by wildfires due to recent experiences in the Western United States. Test. Meyer 22. FEA supported increasing Wildfire Plan expenditures that can be justified and recognized that current rates do not recover the proposed increased expenses. *Id.* 22.

259. FEA asserted the weather station expense of \$2.5 million and the ground assessments expense of \$3.5 million should be disallowed. Test. Meyer 22. Based on NorthWestern’s response to Data Request FEA-075, FEA argued there is not sufficient information to allow recovery of weather station expense at this time. *Id.* at 22–23. According to FEA, NorthWestern did not quantify the number of weather stations that are operating in Montana, and therefore cannot predict if weather stations are needed. *Id.* Further, FEA questioned NorthWestern’s reliance on third-party vendors’ data and analysis since they are motivated to sell their products. *Id.* at 23. Regarding ground assessments, FEA proposed that 50% of the sub-transmission system be assessed by the ground each year, rather than NorthWestern’s proposal of performing 100% ground assessments of sub-transmission and distribution systems and 20% of transmission systems annually. *Id.* 24; Ex. GFB-1 14. FEA stated the lack of information regarding the \$3.5 million in ground assessments justified FEA’s recommended modified assessment. *Id.*

260. Overall, FEA acknowledged that, “given the heightened concerns over wildfires and NorthWestern’s lack of specific knowledge to address this operational problem, the use of a rider should be endorsed until a more definitive direction in wildfire mitigation can be learned.” Test. Meyer 25. Further, FEA stated that FEA had, “previously proposed use of a tracker by another utility when dealing with increased expenses for compliance with a Commission rule on vegetation management and infrastructure inspections.” *Id.* 27.

261. HRC/NRDC/NWEC recommended the Commission reject the Wildfire Plan rider proposal. HRC/NRDC/NWEC instead recommended the Commission require NorthWestern to complete a stakeholder process that would allow parties to discuss and work towards a consensus. HRC/NRDC/NWEC believed NorthWestern should invest in wildfire mitigation, but in a manner that allowed due diligence, transparency, prudence, and an overall good process. Test. Levin 4.

262. HRC/NRDC/NWEC expressed concern that there was not enough information as to the activities, cost of the activities, projected timeline, long-term needs, or expected use and length of the Wildfire Plan to warrant approval. *Id.* at 32. HRC/NRDC/NWEC would prefer NorthWestern identify clear deficiencies in the test year wildfire mitigation budget; provide estimated costs for incremental wildfire mitigation activities based on already-completed analysis and expertise that provides greater certainty to the scope and cost of the plan; and design a term-limited rider that would build out wildfire mitigation programs in the near term. *Id.* at 35.

263. Walmart opposed the creation of the Wildfire Plan rider. If the Commission approves the rider, however, Walmart recommended allocating the costs on a dollar per customer basis, rather than on an energy basis. Test. Teague 18–19. Walmart stated the Wildfire Plan rider did not have a finalized plan or scope behind it and without either of those, it was difficult to ascertain the need for a rider to recover the costs. *Id.*

264. 350 Montana noted that NorthWestern justified its Wildfire Plan rider by citing increased fire events and extreme weather. 350 Montana considered these

justifications illogical because NorthWestern did not include climate or wildfire trends, modeling, or carbon/methane emission impacts in its decision to build a gas plant. Test. Steven Running 14 (Dec. 19, 2022).

265. With the understanding that wildfire mitigation needs and risks continue to grow, NorthWestern asserted the Wildfire Plan rider was adequately developed and crucial for the Commission to approve. Test. Fang (Policy) 16. NorthWestern refuted MCC's claim that wildfire costs were not sufficient to require a rider, as the costs occur outside of the timeline for costs addressed in the current rate review. *Id.* at 17. NorthWestern also refuted FEA's claims that NorthWestern will not have new capital costs to include in the rider. NorthWestern pointed out that of the \$288 million in estimated costs, \$193.3 million were expected to be capital. *Id.*

266. In response to Walmart and NRDC/HRC/NWEC's claims, NorthWestern asserted the Wildfire Plan rider's scope was defined, and the next steps were to further refine the scope for each year. NorthWestern stated that it would be burdensome, inefficient, and potentially dangerous to establish an assessment plan year in advance that would detail exact dates. NorthWestern stated that allowing the operations department flexibility to meet objectives throughout a given time period, as the Wildfire Plan rider provides, would be the most cost effective and safest way to program success. Test. Bailly 4, 5.

267. NRDC/HRC/NWEC expressed concern regarding the length of the rider. In response, NorthWestern asserted the plan was for items identified to be completed by the end of 2028, and the five-year plan struck a good balance between risks and achievable timeframe. Test. Bailly 5. In addition, NorthWestern stated it intended to develop subsequent versions of the Wildfire Plan that would include further estimated costs and timelines that address the continuing wildfire risks. *Id.*

268. NorthWestern further disagreed with FEA's recommendation to exclude \$2.5 million of weather station expense and \$3.5 million of ground assessment expense. First, NorthWestern noted the two categories of weather station expense include hiring of a third-party vendor and installation of additional

weather stations if necessary. NorthWestern's plan was to hire a third-party vendor who specializes in micro-level weather forecast models for remote areas to help determine if existing weather stations are sufficient. NorthWestern noted that the third-party vendors under consideration did not sell weather stations. Test. Bailly 3.

269. Second, NorthWestern argued it was very important to conduct both ground and aerial assessments to reduce wildfire risk. Once the five-year cycle is complete, NorthWestern would re-evaluate the necessity of all aspects of the assessments. NorthWestern stated that vantages from both the air and the ground level provide opportunities to identify exceptions that could cause an ignition source. NorthWestern claimed a trained line worker was necessary to identify asset life issues and a certified arborist was necessary to determine potential vegetation issues. Test. Bailly 3, 4.

ii. Settlement Agreement

270. Paragraph 16 of the Settlement Agreement addresses the Wildfire Plan rider as follows:

The Wildfire Mitigation Rider will not be approved in this rate review. The [Settling Parties] agree that NorthWestern will defer incremental wildfire expenses, capped annually pursuant to the table attached as Exhibit E, with these costs eligible for recovery, subject to a prudence determination, in NorthWestern's next general rate review.

Settlement Agreement Exhibit E. - Wildfire Deferred Accounting Caps			
Incremental Wildfire Mitigation - Annual Expenses			
Year	Operating Expenses	Estimated FERC Credit	Total
2023	\$1,623,113	(\$332,069)	\$1,291,044
2024	\$17,130,462	(\$3,723,272)	\$13,407,190
2025	\$22,979,890	(\$6,073,309)	\$16,906,581
2026	\$21,809,694	(\$7,324,882)	\$14,484,812
2027	\$16,962,782	(\$7,743,634)	\$9,219,148
2028	\$14,948,520	(\$8,526,676)	\$6,421,844
Total	\$95,454,461	(\$33,723,842)	\$61,730,619
Incremental Wildfire Mitigation - Cumulative Expenses			
	Operating Expenses	Estimated FERC Credit	Total
2023	\$1,623,113	\$1,623,113	\$1,623,113
2024	\$18,753,575	(\$4,055,341)	\$14,698,234
2025	\$41,733,465	(\$10,128,650)	\$31,604,815
2026	\$63,543,159	(\$17,453,532)	\$46,089,627
2027	\$80,505,941	(\$25,197,166)	\$55,308,775
2028	\$95,454,461	(\$33,723,842)	\$61,730,619
This chart appears as Exhibit ADD-15.			

iii. *Discussion and Findings*

271. Wildfire mitigation and safety has been a priority for this Commission. In Docket 2018.02.012, the Commission approved NorthWestern's Hazard Tree Removal Program to remove mountain pine beetle impacted tress along 1,030 miles of NorthWestern's Transmission and Distribution system to prevent the beetle killed trees from falling onto the power lines and sparking wildfires. The Commission ordered NorthWestern to continue its Hazard Tree Removal program with minimum annual expenditures of \$3.2 million citing the benefits of the program to both NorthWestern and the health and safety of Montana residents. *In re NorthWestern Energy's Appl. to Increase Elec. Rates*, Dkt. 2018.02.012, Order No. 7604u ¶ 150 (Dec. 19, 2019).

272. The Commission approves the deferred accounting for wildfire

mitigation costs as agreed to by the Settling Parties in paragraph sixteen of the Settlement Agreement. This approval does not bind the Commission to approve those expenses for recovery but does allow NorthWestern to track those expenses and ask for recovery in the next general rate case (subject to the caps as proposed in Exhibit E. to the Settlement Agreement).

273. In paragraph 16 of the Settlement Agreement, the Settling Parties agreed that the Wildfire Plan rider would not be approved in this rate case, so no findings are necessary on this issue.

E. Business Technology Rider

i. Parties' Positions

274. NorthWestern requested approval of a new rate mechanism that would recover certain Business Technology and Cyber Security expenses on an annual inflation-adjusted basis indexed to the GDP deflator index ("BT Rider"). Test. Nelson 5. NorthWestern found 2021 actual costs adjusted for 2022 known and measurables to not adequately reflect costs going forward. Test. Fang (Policy) 22. NorthWestern asserted adequately funding business technology programs are critical to providing safe and reliable service to customers. *Id.* 23. NorthWestern proposed to re-examine the trends in business technology costs in its next regulatory rate review to determine whether the inflation-adjusted increase remains warranted in future recovery of the costs. Test. Nelson 5.

275. MCC argued against the BT Rider asserting that the costs are not substantial enough that they cannot be recovered using traditional rate making methods. Test. Dismukes 43. In addition, MCC argued that the types of costs associated with the BT Rider do not have the characteristics that are appropriate for recovery through a cost tracker that would shift more risk onto ratepayers. *Id.* at 44.

276. LCG also recommended against the BT Rider an example of single-issue ratemaking and that NorthWestern management should be expected to cope with normal business risk and the operation of economic forces without resorting to

single issue ratemaking. Test. Higgins 34.

277. FEA did not support the BT Rider as the FEA found it was single-issue ratemaking and addressed inflationary pressures on only one aspect of NorthWestern's operations. Test. Meyer 9.

278. HRC/NRDC/NWEC asserted the details of the BT Rider and the rationale behind the rider's actual construction are lacking. Test. Levin 36. In particular, HRC/NRDC/NWEC stated NorthWestern provided little support as to the selection and use of inflation as an index to escalate cost recovery. *Id.*

279. Walmart expressed concern that the business technology costs proposed to be recovered through the rider do not appear to represent a new or unique need that would justify rider recovery versus base rate recovery. Test. Teague 18.

ii. Settlement Agreement

280. In paragraph 17 of the Settlement Agreement, the Settling Parties agreed that the BT Rider would not be approved in this rate case.

iii. Discussion and Findings

281. Through the Settlement Agreement, NorthWestern has withdrawn its request for approval of the BT rider and, therefore, no findings are necessary on this issue.

IV. Other Contested Issues

A. Demand Side Management

i. Parties' Positions

282. NorthWestern currently recovers DSM costs through the PCCAM. NorthWestern stated that DSM is defined as a supply resource. Test. Berzina 24 (citing Mont. Admin. R. 38.5.8202). NorthWestern stated that DSM reduces the need to purchase or build alternative electric supply resources by reducing customer demand through efficiency gains. Test. Diane L. Williams 3 (Aug. 8, 2022).

Therefore, according to NorthWestern, DSM should be treated as an investment and included in rate base. Accordingly, NorthWestern proposed to defer DSM expenditures with the accumulated balance included in rate base and amortized over a 14-year period. *Id.*

283. MCC opposed NorthWestern's proposal. MCC stated the Commission has previously rejected similar proposals by NorthWestern. Test. Dismukes 78 (citing Commission Dockets 2017.5.39 and 2018.2.012). MCC asserted that DSM capitalization is rare because only nine regulatory jurisdictions allow it. *Id.* at 81. MCC asserted seven of those nine jurisdictions are served by multiple electric utilities and just one of those utilities has been permitted to capitalize DSM expenditures. *Id.* at 80–81. MCC argued amortizing DSM costs will benefit shareholders because NorthWestern will receive a return on and a return of the balance of the regulatory asset. *Id.* at 79. Conversely, MCC argued that treating DSM expenditures as a regulatory asset will lead to higher costs for ratepayers and not be in the public interest. *Id.* at 81 (citing *In re NorthWestern Energy's Appl. to Increase Elec. Rates*, Dkt. 2018.02.012, Order 7604u (Dec. 20, 2019)). MCC asserted the DSM costs should continue to be recovered dollar-for-dollar through the PCCAM. *Id.* at 86.

284. HRC/NRDC/NWEC also opposed NorthWestern's DSM capitalization proposal. Specifically, HRC/NRDC/NWEC expressed concerns with the process and mechanics of the proposal. Test. Brendon Baatz 64 (Dec. 19, 2022). HRC/NRDC/NWEC argued that NorthWestern's proposed 14-year amortization period is excessive and that its proposal would require a significant addition to rate base in the next rate case. *Id.* at 62–64. HRC/NRDC/NWEC proposed that DSM costs should be discussed in stakeholder discussions outside of this rate case. *Id.* at 5.

285. In rebuttal, NorthWestern disputed the testimony of HRC/NRDC/NWEC that capitalizing DSM expenditures will cause significant rate impacts. NorthWestern stated that the rate impact from capitalization would be less than recovery through the PCCAM due to the amortization period. Reb. Test.

Jeffery B. Berzina 22 (Mar. 6, 2023). NorthWestern supported that conclusion with an analysis showing that under the status quo, DSM costs recovered through the PCCAM in 2027 would be about \$10.8 million compared to a total DSM revenue requirement of about \$7.7 million if the same DSM expenditures were capitalized.⁴ *Id.* at 22–23. NorthWestern maintains that its 14-year amortization period reflects an appropriate estimate over which DSM investments produce benefits.

ii. Settlement Agreement

286. The Settling Parties agreed that DSM costs will not be capitalized and will continue to be recovered through the PCCAM. Settlement Agreement ¶ 19.

iii. Discussion and Decision

287. Through the Settlement Agreement, NorthWestern has withdrawn its request to capitalize DSM costs and, therefore, no findings are necessary on this issue.

B. Other DSM Considerations

i. Parties' Positions

288. HRC/NRDC/NWEC states NorthWestern is proposing to continue its current DSM offerings but has not updated program designs, underlying data, budget projections, or savings projections for several years. Test. Baatz 5.. HRC/NRDC/NWEC's primary concern was that NorthWestern is operating its programs based on significantly outdated information and that the utility is undervaluing energy efficiency as a resource due to flawed cost effectiveness analysis. *Id.* at 6. HRC/NRDC/NWEC argued that NorthWestern is underutilizing DSM resources to meet customer demand and that instead of procuring cost effective energy efficiency, the utility is relying on more expensive resources. *Id.*

289. HRC/NRDC/NWEC stated that NorthWestern has not updated its energy savings forecast in six years. *Id.* at 15. HRC/NRDC/NWEC argued the

⁴ \$4,108,490 (Amortization expense) + \$3,607,590 (ROR) = \$7,716,080.

forecast is severely outdated and no longer a useful guide for program delivery. *Id.* HRC/NRDC/NWEC asserted that NorthWestern uses a total resource cost test, but the test NorthWestern uses does not meet industry standards. *Id.*

HRC/NRDC/NWEC also argued that NorthWestern's avoided costs create an unequal playing field for energy efficiency because these costs minimize the utility system benefits of the resource. *Id.* HRC/NRDC/NWEC contended NorthWestern's recent marketing expenses associated with DSM programs inhibit the effectiveness of DSM programs because customers are unaware of the programs. *Id.*

290. HRC/NRDC/NWEC recommended NorthWestern's DSM Advisory Group, which was established on a temporary basis by Commission order in NorthWestern's last electric general rate case, should be made permanent. *Id.* at 57. HRC/NRDC/NWEC asserted the DSM Advisory Group should be tasked with a top to bottom review of NorthWestern's energy efficiency acquisition efforts. *Id.* at 57–58. HRC/NRDC/NWEC also proposed the DSM Advisory Group file a report with the Commission detailing the work of the Group and retain an independent third-party facilitator to lead the discussions. *Id.* at 58.

291. HRC/NRDC/NWEC further recommended that in the first PCCAM docket after the completion of NorthWestern's conservation potential assessment that NorthWestern be required to develop and file a DSM program plan, if the Commission declines to approve both the utility's capitalization proposal and HRC/NRDC/NWEC's recommendation regarding the DSM Advisory Group in this docket. *Id.* 59.

292. NorthWestern disagreed with HRC/NRDC/NWEC's assertion that the DSM program is not cost-effective by arguing NorthWestern reviews cost-effective measures with its administrator to estimate the total amount of energy savings for each cost-effective measure. Reb. Test. Williams 3. NorthWestern argued it reevaluates and administers its program offerings on an annual basis and has used the total resource cost test as a standard for determining DSM cost-effectiveness since 2004.

293. NorthWestern also disagreed that the avoided costs are flawed because

the utility's energy supply department provides updated avoided costs values. Furthermore, NorthWestern asserted this issue is outside the scope of this proceeding, as NorthWestern did not seek cost recovery of specific DSM expenditures in this docket. *Id.* NorthWestern argued marketing efforts at the current expense levels have been reasonable and sufficient as NorthWestern exceeded its annual DSM acquisition goals and forecasted incremental program expenses over the last four years. *Id.* at 7–8.

ii. Commission Decision

294. The Commission finds HRC/NRDC/NWEC's request reasonable. The Commission discusses HRC/NRDC/NWEC's general recommendation for a stakeholder process to discuss alternative regulatory mechanisms, including DSM, in its findings below concerning the fixed cost recovery mechanism.

C. Fixed Cost Recovery Mechanism

i. Parties' Positions

295. The FCRM is a temporary pilot rate adjustment mechanism approved in Docket 2018.02.012 designed to decouple electric fixed cost revenue from energy sales. *In re NorthWestern Energy's Appl. to Increase Elec. Rates*, Dkt. 2018.02.012, Order 7604u (Dec. 20, 2019). Implementation of the FCRM, which applies to the residential and small commercial (GS-1 Secondary non-demand metered) classes, was supposed to occur on July 1, 2020.

296. In August 2020, the Commission granted a request by NorthWestern to delay the start of the FCRM pilot by one year. *In re Public Serv. Comm'n's Investigation into Potential Impacts of COVID-19 on NorthWestern Energy's Fixed Cost Recovery Mechanism*, Dkt. 2020.05.064, Order 7742 (Aug. 19, 2020). In July 2021, the Commission approved a request by NorthWestern to delay implementation by another year. *In re Public Serv. Comm'n's Investigation into Potential Impacts of COVID-19 on NorthWestern Energy's Fixed Cost Recovery Mechanism*, Dkt. 2020.05.064, Order 7742a (July 29, 2021). In June 2022, the

Commission approved a request by NorthWestern request to defer implementation until after this proceeding so NorthWestern could propose modifications to the design of the mechanism. *Id.* Order 7742c (June 9, 2022).

297. In this proceeding, NorthWestern argued that a properly designed decoupling mechanism should make a utility indifferent to the volume of its energy sales by breaking the link between energy sales and the utility's ability to recover its fixed costs. Test. Fang (Policy) 39. NorthWestern stated that, as structured, the FCRM does not achieve this result. *Id.* NorthWestern proposed several changes to the FCRM. *Id.* at 40.

298. MCC proposed that the Commission abandon the FCRM Test. Dismukes 57. MCC contended that the FCRM shifts risk from shareholders to customers and does not provide any customer benefits. *Id.* at 51. MCC stated that NorthWestern's FCRM design changes are not tied to any specific incremental energy efficiency program commitments and savings. *Id.* at 54. MCC asserted that an FCRM without program commitments effectively decouples the problem from the solution because the premise for an FCRM is to remove disincentives to promoting efficiency. *Id.*

299. LCG opposed NorthWestern's FCRM design changes and proposed, as an alternative, eliminating the FCRM altogether. Test. Higgins 40. LCG stated that it opposes decoupling mechanisms generally because the impacts typically extend beyond neutralizing the disincentives to pursue energy efficiency programs. *Id.* at 41. LCG asserted that successful energy efficiency programs are possible without decoupling. *Id.*

300. According to LCG, NorthWestern's design changes, which include applying the mechanism to all customers, stray from the original goal of addressing energy efficiency disincentives, noting that Choice customers are ineligible for NorthWestern's energy efficiency programs. *Id.* at 41–42. LCG maintains that it is common to exclude large customers from decoupling mechanisms. *Id.*

301. HRC/NRDC/NWEC opposed NorthWestern's FCRM design changes but supports decoupling mechanisms. Test. Levin 47. HRC/NRDC/NWEC

recommended that the Commission not approve NorthWestern’s proposed FCRM in this rate case. It believed, however, that a new FCRM could be discussed in a stakeholder process outside of this rate case. *Id.* at 4, 52. HRC/NRDC/NWEC suggested that the Commission utilize the National Association of Regulatory Utility Commissioners (“NARUC’s”) Stakeholder Engagement Decision-Making Framework to guide the development of a stakeholder process. *Id.* at 4, 21–22 (describing scope, facilitation, and engagement processes in a stakeholder process). Specifically, HRC/NRDC/NWEC requested that the stakeholder process establish a set of regulatory objectives, create discussions of different alternative rate making mechanism options and result in a public, actionable report. *Id.* at 24–25.

ii. Settlement Agreement

302. The Settling Parties agreed to eliminate the FCRM. Settlement Agreement ¶ 18.

iii. Discussion and Findings

303. Through the Settlement Agreement, NorthWestern has withdrawn its request to update the FCRM, and, therefore, no findings about NorthWestern’s changes to the FCRM program are necessary.

304. As discussed above in the sections concerning both DSM and the FCRM, HRC/NRDC/NWEC requested that the Commission require a “stakeholder process to discuss and put forward consensus-based solutions around alternative ratemaking approaches, principles, and mechanisms.” Test. Levin 4. The Commission finds value in such discussions.

305. The Commission finds that the NARUC stakeholder process outlined by Amanda Levin on pages 22 and 23 of her testimony, while potentially useful, is more than this Commission is able to take on at this time. Rather, the Commission believes that NorthWestern should lead this stakeholder process. NorthWestern already has an advisory committee designed to assist NorthWestern in its planning processes. *See* Mont. Admin. R. 38.5.2023; *see also* Mont. Code Ann. § 69-3-1208.

Therefore, the Commission believes that such an advisory committee could potentially act as a viable forum for such discussions and, in fact, is consistent with the Legislature's intent when requiring the advisory committee. The Commission also encourages NorthWestern not to limit discussions to the advisory committee but to include a broad range of stakeholders, based on consultation with its advisory committee.

306. The Commission requires that NorthWestern file quarterly reports about the stakeholder process, which must include a set of regulatory objectives, a summary of the discussions about different alternative rate-making mechanism options, and the next steps identified by the stakeholders. The Commission understands that large stakeholder processes may not always result in agreement. In the event stakeholders and NorthWestern agree on the next steps at the end of this process, the Commission would evaluate proposed mechanisms in a subsequent proceeding. In the event no agreement is reached, the Commission will evaluate the results of the stakeholder discussions and determine the appropriate next steps. Ultimately, the Commission recognizes the importance of continued evaluation of opportunities that NorthWestern may have to implement alternative ratemaking approaches. Such approaches mandate stakeholder input, and by adopting the approach outlined above, the Commission believes the process will bear positive results.

D. Deferred Accounting for Small Natural Gas Production Acquisitions

i. Parties' Positions

307. NorthWestern proposed to defer and accumulate costs associated with any strategic natural gas production asset. Test. Berzina 34. NorthWestern requested a deferred accounting order for purchases of natural gas assets that cost less than \$3 million ("Small Natural Gas Assets"). Test. Lafave 19. Through deferred accounting, NorthWestern would accumulate the revenue requirement of such facility, O&M costs, depletion expenses, taxes, and return on rate base from

the time of the asset purchase until included within the utility revenues through a subsequent natural gas rate review. Test. Berzina 34. NorthWestern asserted that continued acquisition of its own natural gas production assets will help provide a reliable natural gas supply at reasonable and stable prices that reflect market conditions. *Id.* at 35.

308. NorthWestern provided several justifications for its deferred accounting proposal for natural gas production assets. NorthWestern argued current ratemaking practices discourage the acquisition of small natural gas production assets. Test. Berzina 34. NorthWestern argued that it does not have a regulatory mechanism to recover the costs of the natural gas production assets before those assets deplete. *Id.* NorthWestern asserted that natural gas reserves are high at the beginning of well use but wells deplete quickly. Test. Lafave 18. According to NorthWestern, this “front-end” depletion means that the asset is depleted early in its life, and to a large degree before NorthWestern can obtain cost recovery through a general rate review. *Id.* NorthWestern requested deferred accounting of its natural gas production assets in order to recover acquisition costs already depleted and expensed prior to a rate review filing. Test Berzina 37.

309. NorthWestern argued under current rules, that if NorthWestern were to acquire a small natural gas production facility, it would capitalize the asset and begin depleting the asset immediately while receiving no recovery of the acquisition itself, depletion, or operating costs. Test. Berzina 36–37. NorthWestern asserted its customers would essentially receive free natural gas for these volumes since this natural gas would replace more expensive volumes that NorthWestern would have otherwise purchased on the market. *Id.* at 37. NorthWestern stated it would not receive any recovery of its costs until it files a subsequent general rate filing. *Id.* Depending on the timing of any subsequent general rate filing, NorthWestern may recover some of the costs associated with the acquired asset, but NorthWestern would never recover acquisition costs already depleted and expensed prior to a rate review filing. *Id.*

310. NorthWestern asserted that its current owned natural gas supply

resources alone are not sufficient to continue to provide reliable service.

NorthWestern stated that it has seen a decline in natural gas volumes from its own and contracted natural gas supply sources. *Id.* NorthWestern asserted the observed decline in natural gas volumes on NorthWestern's system appears to be a function of expected production declines as wells become depleted or are shut-in, and a lack of drilling investment to maintain or enhance production. *Id.* NorthWestern stated that since the last natural gas rate case in 2016, it has acquired additional gas production and reserve assets including small to medium-sized interest in its existing owned assets and other minor interest from individuals wanting to sell their mineral rights and working interests associated with NorthWestern's reserve assets. NorthWestern argues that the acquisition of additional assets addresses the problem of lack of supply from other sources. *Id.* at 17. In addition, the supply of natural gas is firm; meaning that it is available during critical or high demand periods. *Id.* Finally, NorthWestern asserted natural gas production assets located within its own system lessen deliverability risk to NorthWestern customers. *Id.* NorthWestern asserted it is able to operate its wells in ways that ensure production is as reliable as possible. *Id.*

311. NorthWestern stated that natural gas that is purchased through a third party is recovered through the natural gas tracker. *Id.* at 19. However, when a reserve is purchased, it is removed from recovery through the tracker. *Id.* This means the natural gas serves customers without any recovery from customers for the costs until the reserve is added to the rate base at a later time. *Id.* NorthWestern asserted the inability to recover costs for the initial years of a well's production creates a disincentive to acquire the resource because cost recovery for the acquisition is not available. *Id.* Consequently, any transactions between rate reviews, including small transactions, are discouraged due to the magnitude of non-recovered gas value. *Id.*

312. NorthWestern stated the transactions to purchase the Small Natural Gas Assets are measured by the same standards as the guidelines used for large transactions that were published in the 2020 Natural Gas Procurement Plan filed

in Docket 2020.04.046. *Id.*

313. NorthWestern explained that at the point in time when NorthWestern files a subsequent natural gas general rate review, it would include the accumulated balance of the deferred costs in rate base and amortize that balance over a period of three years. NorthWestern argues that three years is a reasonable amortization period for these costs for two reasons: (1) NorthWestern would generally file subsequent natural gas general rate reviews in a cycle of approximately that time and (2) amortization over three years would not lead to significant rate pressures. Test. Berzina 34–35. NorthWestern asserted that deferred accounting and amortization provide NorthWestern the opportunity to fully recover its associated costs and eliminate the existing economic disincentive resulting from the current regulatory mechanisms. *Id.* at 38.

314. At the Hearing, MCC opposed the deferred accounting for the acquisition of natural gas production assets. MCC argued that deferred accounting for small natural gas acquisitions should be addressed in a separate proceeding. Hr’g Tr. 1568:7–12. Also, MCC expressed concern that the NorthWestern proposal includes capital costs. *Id.* at 1567:21–24. MCC asserted that the Commission has never allowed for deferred accounting treatment of capital costs and normally deferred accounting treatment is used for operating expenses. Hr’g Tr. 1567:15–1568:3.

ii. Settlement Agreement

315. The Settlement agreement does not resolve NorthWestern’s request for deferred accounting of small natural gas production assets. Settlement Agreement ¶ 21.

iii. Discussion and Decision

316. The Commission does not find MCC's arguments regarding NorthWestern’s request for deferred accounting of small natural gas production assets persuasive. The record evidence does not support MCC’s position. The

Commission finds that NorthWestern did not request that the Commission approve a regulatory asset. Hr’g Tr. 1373:18–25, 1374:1–25, 1375:1–3. Rather, NorthWestern requested that the Commission approve the ability to defer and accumulate the appropriate costs to bring to the Commission for approval in a future general rate case. Test. Berzina 34.

317. The Commission finds NorthWestern’s arguments persuasive. The Commission finds that NorthWestern’s acquisition of natural gas production assets provide greater reliability for customers, addresses the problem of lack of supply from other sources, provides a firm supply of natural gas, and lessens deliverability risk to NorthWestern customers.

318. The Commission finds that deferred accounting for the small natural gas production assets is appropriate in this instance. The Commission finds that NorthWestern is economically disincentivized to acquire small natural gas production assets using the current method of cost recovery. The Commission finds that deferred accounting treatment of these assets provides better incentives to NorthWestern. The costs accumulated through deferred accounting may include the revenue requirement of such facility, allowing for accumulation and eventual recovery of O&M costs, depletion expense, taxes, and return on rate base for each asset purchase until the costs are included within the utility revenues through a subsequent natural gas general rate review. The Commission finds the three-year amortization period is reasonable. The cost of capital to be utilized in the analysis shall be the overall weighted cost of capital as found previously in this Order, 6.67%.

319. The Commission approves the deferral of costs for the acquisition of small natural gas production assets as requested by NorthWestern. The Commission is not approving the approval of a regulatory asset. The proper accounting treatment of the deferred costs is appropriate to be decided by NorthWestern, depending on NorthWestern’s internal analysis regarding the probability of recovery.

320. Any filing made by NorthWestern in a subsequent general rate review

shall provide sufficient information for the Commission to evaluate each natural gas production asset acquisition for which NorthWestern seeks cost recovery.

NorthWestern shall provide information showing that the prices paid by NorthWestern customers for natural gas from these acquisitions will be commensurate or less than the market prices paid by NorthWestern for natural gas.

E. Sleepy Hollow

i. Parties' Positions

321. NorthWestern acquired the Sleepy Hollow natural gas system in 2022. Test. Berzina 30. NorthWestern stated it will true up the beginning and ending of year simple-average of the estimated \$0.6 million net book value using actuals. *Id.* NorthWestern asserted the \$0.6 million dollar figure is derived from the net book value of approximately \$0.5 million and an outstanding balance of \$0.1 million from Sleepy Hollow for unpaid natural gas supply costs provided by NorthWestern. *Id.*

322. In addition, NorthWestern sought recovery of any and all expenses related to necessary maintenance and operation of the system. *Id.* at 38. NorthWestern stated a known and measurable adjustment will be included within the revenue requirement for the actual 2022 expenses incurred. *Id.* 39 NorthWestern anticipated ongoing expenses for the acquisition past 2022 and therefore proposes to defer and accumulate any costs incurred in excess of the included 2022 known and measurable adjustment. *Id.* Upon a subsequent natural gas general rate review, NorthWestern stated it would include in its revenue requirement the amortization of the accumulated balance of the deferred costs, utilizing an amortization period of three years. *Id.*

323. MCC expressed concerns with rate basing the remaining book value, the ratemaking treatment for the cost of gas supplied, and future operation and maintenance expenses. MCC argued Sleepy Hollow is not worth the remaining net book value prior to the owner filing bankruptcy. Test. Ralph Smith 95-96. MCC argued that based on the deteriorated condition of the system and the fact that the system had no value under the previous ownership, NorthWestern should be

recording the existing net book value of zero or the \$1 acquisition price

NorthWestern paid for the system. *Id.* at 98

324. MCC contended that if the previous owner's net book value is rate based, existing NorthWestern customers would be harmed by having an amount added to rate base well beyond what NorthWestern paid to acquire Sleepy Hollow. *Id.* at 97–98. Therefore, MCC recommended the rate base amount for Sleepy Hollow reflect the amount NorthWestern paid for the system. *Id.* at 98.

325. With regard to the ratemaking treatment for the cost of gas supplied, MCC proposed the customers who used that gas should pay for it, not NorthWestern's existing ratepayers. *Id.* Therefore, MCC proposed a surcharge and carrying charge for Sleepy Hollow customers. *Id.*

326. In addition, MCC disagreed with NorthWestern's proposal to defer any costs incurred in excess of the included 2022 known and measurable adjustment. *Id.* at 100. Moreover, MCC contended it is premature to pre-determine for a future rate case the ratemaking treatment and asserted it would be more appropriate to determine any increased costs in NorthWestern's next natural gas rate case. *Id.* at 101.

327. NorthWestern opposed MCC's proposals, arguing MCC's recommendations ask the Commission to treat Sleepy Hollow as if it were like any other acquisition although nothing about the acquisition was business as usual. Reb. Test. Fang (Policy) 24. NorthWestern noted that aside from the bankruptcy of the majority owner of the parent company and the failure of its day-to-day operations, Sleepy Hollow had failed to meet regulatory compliance requirements since 2020, posing a safety risk to the community. *Id.* at 25. NorthWestern asserted the only way to ensure customers of Sleepy Hollow had natural gas service was for an experienced system operator to take over. *Id.* Further, NorthWestern asserted that it only seeks the ability to rate base the fair market value of the Sleepy Hollow assets, the outstanding balance in unpaid natural gas supply costs, expenses related to operations and maintenance, and the measurable adjustments incurred in 2022. *Id.*

328. NorthWestern argued against assigning all costs directly to the citizens of Sleepy Hollow, claiming costs would be punitive given the size of the community. *Id.* at 26. Instead, NorthWestern asserted it is in the public interest to share the costs with NorthWestern's entire natural gas customer base. *Id.* For these reasons, NorthWestern recommended rejecting MCC's adjustments.

ii. Settlement Agreement

329. In the Settlement Agreement, the Settling Parties agreed to NorthWestern's proposed rate base and operating maintenance expenses reflected in the rebuttal testimony of Jeffrey B. Berzina and the deferred cost treatment discussed in the direct testimony of Jeffrey B. Berzina. Settlement Agreement ¶ 7. The Stipulating Parties acknowledged that there is no acquisition premium being claimed or recovered by NorthWestern. *Id.*

iii. Discussion and Decision

330. The Commission finds that including the rate base and operating expenses associated with Sleepy Hollow in the natural gas TD&S revenue requirement is reasonable. In addition, the Commission approves the deferred accounting treatment as proposed by NorthWestern witness Jeffrey Berzina. At the Hearing, NorthWestern clarified that the rates agreed to in the Stipulation are detailed in Data Resp. MCC-337. Hr'g Tr. 738:17–739:13. In response to MCC-337, NorthWestern provided the updated actual net plant addition and expenses for Sleepy Hollow to be included in the gas revenue requirement as follows:

Total Plant Added in 2022 for th Sleepy Hollow Purchase	
376.1 Gas Distribution Mains	\$155,811.72
381.0 Gas Distribution Meters	\$23,902.86
392.9 Gas Trailers	\$9,682.10
393.0 Gas General - Stores Equipment	\$9,682.10
398.0 Gas General - Miscellaneous	\$12,320.08
Total	\$211,398.86
Increase to Rate Base*	\$105,699.43
*Rate Base is calculated on a simple average so the increase to rate base is one-half of the total plant additions.	
Distribution Operations Expense	\$25,060
Source: NorthWestern Response to MCC-337	

Data Resp. MCC-337 (Mar. 30, 2023).

331. The Commission finds the Stipulation reasonable regarding the inclusion of capital and expense impacts of Sleepy Hollow on the gas revenue requirement as presented in the above table from the response to Data Request MCC-337.

F. Jurisdictional Cost of Service Study

332. In Docket 2018.02.012, the Commission directed NorthWestern to file a jurisdictional cost-of-service study in its next rate case to evaluate whether the FERC revenue credit approach produces reasonable results for retail customers. *In re NorthWestern Energy's Appl. to Increase Elec. Rates*, Dkt. 2018.02.012, Order 7604v, ¶¶ 121–128 (May 20, 2020). The Settlement Agreement requires NorthWestern to file a comprehensive jurisdictional cost of service study of all costs associated with providing wholesale services in its next general electric rate review. Settlement Agreement ¶ 6.

i. Discussion and Findings

333. The Commission finds paragraph 7 of the Settlement Agreement reasonable and consistent with the Commission's decision in Docket 2018.02.012.

G. Lighting Tariff Changes

i. Settlement Agreement

334. In the Settlement, the Settling Parties accepted the proposed lighting tariff changes as set forth in the testimony of Cynthia S. Fang. Settlement Agreement ¶ 9. The Commission finds those changes reasonable and appropriate.

Conclusions of Law

335. All findings of fact that are properly construed as conclusions of law are incorporated herein and adopted as such.

336. The Commission has full power of supervision, regulation, and control of public utilities. Mont. Code Ann. § 69-3-102 (2021). NorthWestern is a “public utility” subject to regulation by the Commission as it provides electric service within the state of Montana. Mont. Code Ann. § 69-3-101.

337. Procedural due process is flexible and calls for such procedural protections as the particular situation demands. *Geil v. Missoula Irrigation Dist.*, 2002 MT 269, ¶ 58, 312 Mont. 320, 59 P.3d 398. “The fundamental requirement of due process is the opportunity to be heard at a meaningful time and in a meaningful manner.” *Id.* ¶ 61 (internal quotation marks and citations omitted). The Commission concludes it has provided adequate public notice of this proceeding and an opportunity for all interested parties to be heard.

338. The rates charged by a utility must be just and reasonable. Mont. Code Ann. § 69-3-330. Determining “just and reasonable rates” involves a balancing of investor and consumer interests. *Fed. Power Comm’n. v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1942). The Settlement Agreement was a result of compromise between NorthWestern, the representative of several large customers (LCG), the representative of federal agencies (FEA), Walmart, and the representative of the interests of the consuming public (MCC). These were the primary parties offering testimony, evidence, and expert analysis of the financial aspects of this case. The fact that these parties have reached a settlement suggests that the result is a just and reasonable balancing of interests. Having reviewed the Settlement Agreement and the record in its entirety, the Commission concludes that the Settlement

Agreement results in rates that reasonably and fairly balance the interests of NorthWestern and its customers.

339. A utility is entitled to an opportunity to earn a fair return on the value of its investment. *Bluefield Water Works & Improvement Co. v. Public Serv. Comm’n*, 262 U.S. 679, 690 (1923) (citing *Smyth v. Ames* 169 U.S. 466, 547 (1898)). The return should be commensurate with returns on investments in other enterprises having corresponding risks. *Hope Nat. Gas Co.*, 320 U.S. at 603. The Commission concludes that the ROE approved in this Order is commensurate with the returns on investments in other enterprises having corresponding risks.

340. In determining just and reasonable rates, the Commission is not bound “to the use of any single formula or combination of formulae.” *Id.* at 602. Rather, the Commission should review the impact of the rates in their entirety to determine whether they are just and reasonable. *Id.* The Commission concludes that the rates proposed in the Settlement Agreement are just and reasonable because, as discussed in detail above, the revenue requirements described in the Settlement Agreement fall within a range of reasonableness. The Commission also concludes that the rate design and the class allocation in the Settlement Agreement are reasonable. Together, the revenue requirement, the rate design, and class allocation result in just and reasonable rates.

Order

341. NorthWestern’s Application is approved as described above.

342. NorthWestern is directed to file tariffs in compliance with this Order as soon as is practicable, and no later than October 30, 2023.

343. The rates approved in this settlement will be effective for service rendered on and after November 1, 2023.

344. NorthWestern shall, when implementing final rates from this Order, utilize the 2023 stepped-down revenue requirement from the table shown in paragraph 128 of this Order.

345. Any party may petition for reconsideration of this Order as provided in

Mont. Admin. R. 38.2.4806.

DONE and DATED September __, 2023, by the Montana Public Service
Commission by a vote of __ to __.

DRAFT