Service Date: December 20, 2019

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

IN THE MATTER OF NorthWestern Energy's Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design	)	REGULATORY DIVISION DOCKET NO. 2018.02.012 ORDER NO. 7604u

FINAL ORDER

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SUMMARY

1. This is NorthWestern Energy's ("NorthWestern" or "NWE") first electric rate case before the Montana Public Service Commission ("Commission" or "PSC") as a vertically integrated utility. Prior to this Application, it had been almost ten years since NorthWestern's last electric rate case as a distribution and transmission service provider. *In re NorthWestern's 2009 Application,* Dkt. 2009.9.129. In this intervening period NorthWestern has made significant investments to expand its owned generation assets (Colstrip Unit 4, Dave Gates Generating Station, Spion Kop Wind Farm, PPL hydroelectric purchases, Two Dot Wind Farm). *See In re Colstrip Pre-Approval,* Dkt. D2008.6.69; *In re Dave Gates Pre-Approval,* Dkt. D2008.8.95; *In re Spion Kop Pre-Approval,* Dkt. D2011.5.41; *In re Hydro Asset Pre-Approval,* Dkt D2013.12.85. While NorthWestern established individual revenue requirements for most of those generation assets through Montana's pre-approval statutes, this is the first comprehensive review of NorthWestern's operations as a combined generation, transmission, and distribution electric utility.

2. The Commission approves an overall $6.5 million increase for NorthWestern's electric utility operations in Montana. This represents an $18,414,385 increase to NorthWestern's Transmission and Distribution revenue requirement, yet reduces NorthWestern's Generation revenue requirement by $11,914,385. With this Final Order, NorthWestern will be permitted to recover approximately $600 million annually from Montana electric customers, based on a $2.33 billion electric utility rate base which now includes the 10-megawatt Two Dot wind farm ("Two Dot"). This $600 million annual revenue requirement includes both FERC-jurisdictional and Montana-jurisdictional revenues.

3. This increase is allocated across a variety of customer classes, ranging from a 6.07% decrease for Transmission GS-2 customer classes, to a 5.00% increase for Irrigation customers. Residential and Secondary GS-1 customer classes—which account for the overwhelming majority of NorthWestern's customers—receive a 1.68 and 1.95% increase in rates, respectively. Monthly fixed customer charges also increased 2.00% for Residential customers, increasing the monthly fixed charge to $4.20 from the current $4.10.

4. This increase is based on an overall 6.92% rate of return ("ROR"). This ROR includes a 9.65% Return on Equity ("ROE"), excluding NorthWestern's 10.0% ROE for its

ownership interests in Colstrip Unit 4 ("CU4"), a 4.26% cost of long-term debt, and based on a capital structure comprised of 50.62% long-term debt and 49.38% equity.

5. The Commission also reduces NorthWestern's overall depreciation expense by $9,296,178. This includes a $4,229,142 reduction in NorthWestern's transmission depreciation expense, a $3,838,163 reduction in NorthWestern's distribution expense, and a $1,228,873 reduction in NorthWestern's Dave Gates Generation Station ("DGGS") depreciation expense. Additionally, the Commission observes that NorthWestern is only permitted to adjust its depreciation schedules and expenses as permitted by the Commission.

6. This $6.5 million increase will be effective for rates beginning March 1, 2020. The Commission initially approved a $10,544,411 interim rate increase for NorthWestern on March of 2019. By February 29, 2020, NorthWestern will have collected approximately $3.74 million above the $6.5 million authorized by this Order. This amount will be refunded to customers with interest, over a one-year period.

7. The Commission approves NorthWestern's base supply costs and credits of $138,655,703 for its electricity supply cost tracker. This is comprised of $96,353,668 annual Category One power supply costs and $76,952,206 in Category Two power supply costs, and offset by $34,650,171 of Category One power supply credits. CU4 Variable costs continue to remain NorthWestern's highest Category One power cost at $22,860,046 annually. Qualifying Facility ("QF") Tariff Contracts continue to remain NorthWestern's highest Category Two power cost at $43,811,022 annually. While On-System Market Sales continue to remain NorthWestern's highest Category One power credit at $19,578,957 annually. This $138.6 million amount is in addition to the $600 million approved for NorthWestern's non-PCCAM related revenue requirement, with the actual amount fluctuating annually based on NorthWestern's incurred power supply costs and credits.

8. The Commission finds the annual amortization of ($553,991) in Excess Accumulated Deferred Income Tax ("EADIT") expense is a reasonable agreement between the parties. This amount was within the broad range of advocated-for EADIT expenses, which ranged from $387,065, to ($3,073,309).

9. The Commission refrains from reaching a decision on the Colstrip revenue requirement, as it is neither appropriate nor necessary to selectively approve a single element of the overall generation revenue requirement in order to assess whether the Stipulation results in

just and reasonable rates, and because the provision is an agreement between the parties which does not require additional Commission action.

10. The Commission directs NorthWestern to continue its current Hazard Tree Removal Program with a $3.2 million minimum annual expenditures, and to annually report to the Commission on the status of the program.

11. The Commission continues the current method for crediting retail customers with any Federal Energy Regulatory Commission ("FERC")-jurisdictional transmission revenues. Currently this FERC transmission revenue credit amounts to an approximate $54 million annual credit to retail customers. The FERC is currently considering NorthWestern's transmission rate case, which will likely result in an amended revenue credit. To align NorthWestern's revenues between the two jurisdictional customer-bases, NorthWestern is directed to file a true-up of its current transmission revenue credit with this Commission within 60 days of a final order from the FERC.

12. The Commission approves a Fixed Cost Recovery Mechanism ("FCRM") pilot program. The FCRM will apply to NorthWestern's residential and GS-1 Secondary non-demand-metered classes for a four-year trial period. The FCRM is intended to decouple NorthWestern's recovery of fixed costs from its sales of energy. Although the revenue requirement stipulation provided for a potential 25 basis point reduction to NorthWestern's ROE if the FCRM pilot was adopted, the Commission declines to reduce NorthWestern's ROE in this docket. Rather, the pilot will be governed by various performance metrics, and re-evaluated at the conclusion of the pilot to determine if it should be continued, and to what extent NorthWestern's revenue volatility is mitigated, warranting a potential reduction to NorthWestern's ROE.

13. The Commission declines to establish a new net metering customer class. The current net metering tariff needs revision and the establishment of a net metering rate class is generally warranted. However, because NorthWestern failed to comply with the Commission's Minimum Information Requirements for its net metering benefit-cost analysis and because NorthWestern's proposed rate structure for a new class rests upon a flawed methodology, the Commission denies NorthWestern's request.

14. The Commission rejects an agreement between various parties concerning NorthWestern's Demand-Side Management ("DSM") programs. In doing so, the Commission directs NorthWestern to establish a stakeholder group to evaluate NorthWestern's DSM

programs and make recommendations as necessary. The Commission also rejects a 10% adder for DSM cost-effectiveness measurements, and continues the practice of requiring NorthWestern to expense DSM costs, tracked annually in NorthWestern's electricity supply cost tracker, as opposed to allowing those costs to be capitalized and included within NorthWestern's rate base.

15. The Commission declines to initiate a Colstrip investigation docket, to require community transition funds, and to require additional reporting requirements at this time.

16. The Commission declines to establish a residential crediting mechanism to allow the Federal Executive Agencies ("FEA") to receive credit for power transmitted to NorthWestern by WAPA. The Commission is interested in the proposal, however there is insufficient record evidence to support adopting the mechanism at this time. Rather, the Commission directs the parties to negotiate a mechanism for Commission approval. If the parties cannot agree, the Commission will initiate a subsequent contested case proceeding to address this proposal.

17. The Commission approves a settlement between several parties regarding NorthWestern's E+ Green tariff. This agreement will establish a stakeholder group that will review and assess NorthWestern's E+ Green program to determine if any revisions are warranted.

18. The Commission amends NorthWestern's ELDS-1 Tariff for street lighting customers based on the lighting class revenue requirement for base rate revenues resulting from NorthWestern's ECOS study, adjusted to reflect the Commission-approved stipulation on revenue requirement.

19. The Commission discontinues NorthWestern's annual compliance filing for the Spion Kop wind farm.

20. The Commission declines to establish an after-hours reconnection charge. The Commission also approves a variety of minor, uncontested changes to several NorthWestern tariffs as discussed below.

PROCEDURAL HISTORY

21. On September 28, 2018, NorthWestern filed its Application to Increase Retail Electric Utility Service Rates and for Approval of its Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design ("Application") with the Commission.

22. NorthWestern requested a $34,861,573 increase in annual base electric rate revenue, a 10.65% ROE and an overall 7.42% rate of return (except for CU4 which has a ROE of

10.0% and an overall ROR of 8.25%). The requested increase in annual revenue equates to a 6.64% increase in electric transmission, distribution, and generation revenue. For a typical residential customer using 750 kWh per month of electricity, the total bill impact would be approximately $6.37 per month, or an increase of 7.39%. NorthWestern also requested an interim increase of $13,846,956.

23. The Commission subsequently granted intervention to the Montana Consumer Counsel ("MCC"), Large Customer Group and FEA ("LCG", "LCG/FEA"), Walmart, Department of Environmental Quality ("DEQ"), Human Resource Council District XI and National Resource Defense Council ("HRC/NRDC"), Montana Environmental Information Center and Sierra Club ("MEIC/SC"), Northwest Energy Coalition ("NWEC"), the Northern Cheyenne Tribe ("Northern Cheyenne"), and Vote Solar and Montana Renewable Energy Association ("VS/MREA"). It granted late intervention to Leo and Jeanne Barsanti ("Barsantis"), and Talen Montana, LLC ("Talen").

24. In response, MCC proposed an overall $17.3 million revenue requirement decrease, while LCG/FEA proposed an overall $2.9 million decrease. In rebuttal, NorthWestern proposed a $30.7 million revenue requirement increase. On February 26, 2019, the Commission issued Order 7604r, which authorized a $10,544,411 interim rate increase for NorthWestern's electric services.

25. On November 16, 2018, the Commission issued Procedural Order 7604b, which established a variety of procedural and substantive requirements for this docket.

26. On November 26, 2018, NorthWestern filed a Motion for Reconsideration and Clarification of Procedural Order. NorthWestern proposed that the Commission strike the provisions of Order 7604b authorizing Commission-issued data requests.

27. The Commission issued Order on Reconsideration 7604g, which suspended most of the procedural deadlines in Order 7604b but retained a scheduled on-site audit and deadlines for intervenor data requests. The Commission resolved to refrain from issuing its own data requests pending further consideration of its legal authority. The Commission requested briefing from the parties on the scope of its authority to obtain information from regulated entities and appropriate procedures for doing so.

28. On December 27, 2018, the Commission issued a Notice of Commission Action reinstating the procedural deadlines in Order 7604b and extending the deadline for discovery to

NorthWestern. The Commission also adopted the use of Inquiries pursuant to Mont. Code Ann. § 69-3-106 and Notices pursuant to Mont. Code Ann. § 69-2-102 as its primary information-gathering mechanisms. Accordingly, on January 4, 2019, the Commission issued 102 inquiries to NorthWestern on a variety of subject areas where the Commission determined record evidence was lacking.

29. On January 22, 2019, NorthWestern filed a Motion for Oral Argument regarding the Commission's use of Inquiries and Notices as information-gathering mechanisms. The Commission held oral argument on February 15, 2019. On March 1, 2019, the Commission accepted NorthWestern's representations "that this case is unique in that a significant number of intervenors—more than the typical contested case proceeding before the Commission—are present" and accordingly withdrew its 102 Inquiries and Notices, as this investigatory role was presumed to be performed sufficiently by the parties. Not. of Add'l Issues, ¶ 23. In doing so, the Commission noted that its decision on the issue was not precedential for future Commission proceedings. *Id,* ¶ 22, *citing NorthWestern Corp. v. Mont. Pub. Serv. Comm'n,* Cause No. DV-16-1236 at 5–6 (Mont. 13th Jud. Dist. Ct. 2018).

30. Beginning May 13, 2019, the Commission held a ten-day evidentiary hearing at its offices in Helena, Montana.

31. The Commission received three settlements on various issues from the parties. On May 10, 2019, the Commission received an initial revenue requirement settlement between NorthWestern, MCC, LCG/FEA, and an amended settlement between the same parties on May 13, 2019 ("RR Stipulation"). Appendix A. On May 13, 2019, the Commission also received a settlement agreement between NorthWestern, DEQ, MCC, and Walmart regarding NorthWestern's E+ Green tariff. Appendix B. On May 20, 2019, the Commission received a settlement agreement between NorthWestern and NWEC, regarding NorthWestern's electric DSM programs. Appendix C.

32. During a regularly scheduled work session on October 30, 2019, the Commission approved the Revenue Requirement and E+ Green settlements, and during a regularly scheduled work session on November 25, 2019, the Commission decided various remaining contested issues, as discussed below.

FINDINGS OF FACT

33. This Order includes findings on various revenue requirement issues including NorthWestern's: general revenue requirement and settlement; cost of capital; depreciation expense; excess accumulated deferred income tax expense; electricity supply cost tracker base costs; FCRM pilot; regulatory plant adjustment functionalization; 2018 property taxes; Colstrip; Two Dot acquisition; FERC transmission revenue credits; hazard tree removal; and total revenue requirement and refund.

34. This Order also includes findings on various rate design issues including NorthWestern's: general rate design and settlement; monthly delivery service charges; irrigation customers; net metering customers; WAPA/FEA proposal; E+ Green tariff; street lighting tariff; after-hours reconnection charge; and ancillary tariff revisions.

35. This Order also includes findings on various other contested issues including: three issues related to Colstrip; NorthWestern's DSM programs; the MCC's request for a jurisdictional cost-of-service study; elimination of NorthWestern's annual Spion Kop compliance filing.

I. Revenue Requirement

A. General Revenue Requirement & Settlement

i. *Party Positions*

36. In its Application, NorthWestern requested an overall $34,861,573 increase in its annual electric revenue requirement, including a $3,045,750 reduction in its total generation revenue requirement. Test. Glenda Gibson at 3; Ex. NWE GJG-1 at 1; Statement G (Sep. 28, 2018). NorthWestern's overall increase and total generation revenue requirement include:

I: NorthWestern Overall and Generation Revenue Requirements

Overall Revenue Requirement	
Transmission and Distribution	$37,991,919
Total Generation	($3,045,750)
Two Dot	($4,656)
Total Requested Increase	$34,861,573
Generation Revenue Requirement	
CU4	($10,040,467)
DGGS	$1,858,602
Spion Kop Wind	$19,502
Hydroelectric Assets	$1,742,621
Electric Supply: Non-PCCAM	$2,587,049
Montana Generation (RFP)	$786,049
Total Generation	($3,045,750)

37. In response, the MCC recommended an overall reduction of NorthWestern's Revenue Requirement of ($17,320,818), a reduction of ($52,182,391) from NorthWestern's request. Exhibit MCC RCS-1 at 3 (Feb. 12, 2019); Exhibit MCC RCS Sched A at 4. The following table summarizes MCC's recommendation:

II: MCC Overall Revenue Requirement

ROE Adjustments	
Reducing Non-CU4 ROE from 10.65% to 8.75%	($29,607,601)
Rate Base Adjustments	
PSC/MCC T&D Taxes	($289,869)
Accumulated Depreciation	($1,758,458)
Accumulated Depreciation	$335,746
Cash Working Capital	$70,747
Accumulated Deferred Taxes – Pension Liability	($2,614,419)
CU4 – Capitalized Repairs	($47,401)
Total Rate Base Adjustments	($4,303,654)
Net Operating Income Adjustments	
Depreciation Expense T&D – Depreciation Study	($7,496,551)
Depreciation Expense – Restatement from Accum. Depr.	($858,290)
Depreciation Expense – Butte General Office	($89,772)
Depreciation Expense – Capital Invest. Related to CU4	($17,939)
Vegetation Management	($962,896)
Hazard Tree Management	($239,560)
Directors and Officers Liability Insurance	($171,199)
Rate Case Expense	($171,425)
Incentive Compensation Expenses	($3,322,988)
Payroll Tax Expense	($236,264)
Income Tax Expense – Repairs Deduction	($1,644,494)
Interest Synchronization	$183,172
EADIT Amort. Unprotected Rate Base	($2,626,443)
EADIT Amort. Unprotected Non-Rate Base	($616,500)
Total NOI Adjustments	($18,271,148)
Total Revenue Requirement Reduction	
NorthWestern Initial Request	$34,861,572
MCC Response	($17,320,832)
Total Revenue Requirement Reduction	($52,182,404)

38. Similarly, the LCG recommended an overall reduction of NorthWestern's Revenue Requirement of ($2,921,130), a reduction of ($37,782,719) from NorthWestern's initial request. Test. Kevin Higgins at 7 (Feb. 12, 2019). The following table summarizes LCG's recommendations:

III: FEA/LCG Overall Revenue Requirement

ROR, Net Operating Income, and Rate Base Adjustments	
Transmission Revenues	($5,679,117)
MPC/MCC Taxes – Rate Base	($54,997)
MPC/MCC Taxes – Amortization Exp. Adj. Deferral Exp.	($409,480)
Labor Expense	($528,204)
Incentive Compensation Expense	($3,322,990)
Repairs Deduction	($1,573,688)
OCI EADIT Amortization	($585,402)
CAC EADIT Amortization	($1,221,693)
Pension Liability EADIT Amortization	($2,750,796)
Pension ADIT Amortization	($3,297,913
Hazard Trees Expense	($239,560)
Depreciation Expense	($1,170,379)
Interest Synchronization/Cash Working Capital	$456,642
ROE Reduction from 10.65% to 9.35% (excluding 10.0% CU4 ROE)	($17,592,447)
Functional Rate of Return	$186,978
Regulatory Plant Functionalization	$329
Total Expense, Depreciation, and Tax Adjustments	($37,782,719)
Total Revenue Requirement Reduction	
NorthWestern Initial Request	$34,861,572
FEA/LCG Response	($37,782,719)
Total Revenue Requirement Reduction	($2,921,130)

39. In rebuttal, NorthWestern reduced its revenue requirement from $34,861,573 to $30,701,661, and increased its total generation revenue requirement decrease from ($3,045,750) to ($4,859,110). Ex. NWE GJG-6 (Apr. 5, 2019). The following table summarizes NorthWestern's rebuttal revenue requirement:

IV: NorthWestern Rebuttal Overall and Generation Revenue Requirements

Rebuttal Revenue Requirement	
Transmission and Distribution	$35,565,427
Total Generation	($4,859,110)
Two Dot	($4,656)
Total Requested Increase	$30,701,661
Rebuttal Generation Revenue Requirement	
CU4	($10,425,834)
DGGS	$1,796,014
Spion Kop Wind	($146,794)
Hydroelectric Assets	$532,510
Electric Supply: Non-PCCAM	$2,587,045
Montana Generation (RFP)	$797,949
Total Generation	($4,859,110)

ii. ***Commission Finding***

40. On May 12, 2019, NorthWestern, the MCC, LCG/FEA, and Walmart filed the RR Stipulation with the Commission. The parties stipulated to a $6.5 million increase for NorthWestern's electric revenue requirement, consisting of a decrease in generation revenues of $11,914,385 and an increase in transmission and distribution revenues of $18,414,385. RR Stip. ¶ 1 ("For services rendered on or after the date the Commission approves compliance rates pursuant to its Final Order in this docket, NorthWestern shall be authorized to collect an overall revenue increase of $6.5 million for electric service, subject to any ROE adjustment ordered under paragraph 6 below, consisting of a decrease in generation revenues of $11,914,385 and an increase in transmission and distribution revenues of $18,414,385."). The Settlement Revenue Requirement includes:

V: Settlement Revenue Requirement

Settlement Revenue Requirement	
Transmission and Distribution	$18,414,385
Total Generation	($11,914,385)
Total Requested Increase	$6,500,000
Decrease w/potential 25 BP ROE Reduction (FCRM Pilot)	($3,500,000)
Total Revenue Requirement w/Full BP Reduction	$3,000,000

41. Prior to filing of this Settlement, the MCC requested 20 pro-forma revenue requirement adjustments, while the FEA/LCG requested 16. However, the settlement is a "black-box" as there is no analysis of the proposed adjustments in the RR Stipulation. Rather, the

Commission is presented with an overall $6.5 million increase. The Commission finds some, but not all, of the revenue requirement adjustments in the filed proposals of NorthWestern, MCC, and FEA/LCG reasonable. Together, these findings point to a reasonable revenue requirement change ranging from a reduction of ($1.0) million to an increase of $11.9 million, based on the range of ROEs discussed next in the Cost of Capital section. The Commission concludes that the stipulated revenue increase is within a zone of reasonableness. The $6.5 million increase falls in the middle of the fair and reasonable ranges found in the Commission's analysis and also fall in the middle of the range defined by the parties' respective filed positions. The Commission concludes that the stipulated revenue increase is reasonable and sufficient to allow NorthWestern to attract capital and provide adequate service at just and reasonable rates. The Commission, therefore, approves the $6.5 million revenue requirement increase and the allocation of that increase to T&D and generation. As discussed in the FCRM section below, the Commission declines at this time to make any adjustment to the stipulated $6.5 million revenue requirement increase as the result of a possible 25 basis point ROE reduction. *See* RR Stip. ¶ 6. Although the Commission is approving a total "Generation" revenue requirement reduction in this docket, NorthWestern shall keep its books and records such that, as was filed in this docket, separate revenue requirements for each of the generation assets shall continue to be available to the Commission upon request.

B. Cost of Capital

i. *Capital Structure & Costs of Debt*

42. In deriving the ratemaking capital structure, NorthWestern witness Bird used the 13-month average rate base of the NorthWestern's total Montana utility (gas and electric) as the basis for his calculation. Test. Brian Bird at 4 (Sep. 28, 2018). By deducting the Montana-jurisdictional long-term debt associated with the Montana utility from the total rate base, he derived the amount of equity attributable to the Montana utility. *Id.* He states that this methodology is consistent with past Commission orders, citing to Docket No. D2007.7.82. Since the rate base of NorthWestern's Montana utility is $2.79 billion, subtracting $1.41 billion of long-term debt from this amount results in $1.38 billion of equity attributable to the Montana utility. Ex. BBB-1; Ex. BBB-2; Test. Bird at 10. Based on this, NorthWestern's capital structure is comprised of 50.62% debt and 49.38% equity. Test. Bird at 4.

43. Bird determined that NorthWestern's cost of long-term debt is 4.26% by adding the annual interest expense to the amortization of debt discount and issuance costs (expenses), then dividing the total cost (expense) by the outstanding long-term debt balance. *Id.* at 15.

44. In contrast, MCC witness Hill proposed a hypothetical capital structure. In developing his proposed capital structure, he relied on NorthWestern's consolidated capital structure as the basis for his recommended equity and long-term debt components. Test. Stephen Hill at 22 (Feb. 12, 2019). His recommended capital structure contains 47.25% equity which reflects NorthWestern's average equity balance as a percentage of its total capitalization over the last five quarters. Test. Hill at 22; Ex. SGH-1 at 4. Similarly, it contains 50.10% long-term debt which reflects NorthWestern's average total debt balance as a percentage of its total capitalization over the last five quarters, net of his proposed short-term debt percentage. Test. Hill at 22; Ex. SGH-1 at 4; Data Response ("DR") MCC-061 (Nov. 26, 2018). In deriving his recommended short-term debt percentage, he used the average short-term debt of his proxy group, which he concluded to be 2.65%. Ex. SGH-1 at 4. Accordingly, his proposed capital structure contains 47.25% equity, 50.10% long-term debt, and 2.65% short-term debt. *Id*. He adopts NorthWestern's proposed cost of long-term debt (4.62%), and determined NorthWestern's cost of short-term debt to be 3.04%. DR MCC-061.

45. FEA/LCG did not contest NorthWestern's proposed capital structure.

46. In rebuttal, NorthWestern witness Bird addresses the parties' proposed capital structures. He contends that because utility holding companies typically carry a higher amount of debt than operating companies in order to finance their subsidiaries (including unregulated subsidiaries), it is inappropriate to use the average consolidated capital structure of a proxy group consisting of holding companies to assess the ratemaking capital structure for NorthWestern, which is an operating company. Reb. Test. Bird at 8-9 (Apr. 5, 2019). Moreover, he represents that short-term debt is used for working-capital purposes and is not used to finance the long-term assets included in rate base. *Id.* at 11. The proposed capital structures include:

VI: Proposed Capital Structures & Costs of Debt

Proposed Capital Structure			
Party	Long-Term Debt	Short-Term Debt	Equity
NWE/LCG/FEA	50.62%	0.00%	49.38%
MCC	50.10%	2.65%	47.25%

ii. ***Return on Equity and Weighted Average Cost of Capital***

47. NorthWestern's cost-of-capital witness McKenzie relied on a proxy group of similar-risk publicly-traded utilities, to which he applied a number of analytical models to ascertain a reasonable range of ROEs for NorthWestern. The methods he relied upon are: 1) a Constant Growth DCF model which relies on analyst-provided growth estimates; 2) a Constant Growth DCF model which relies on sustainable growth rates; 3) a CAPM model; 4) an Empirical CAPM ("ECAPM") model; 5) a Utility Risk Premium Model; and 6) an Expected Earnings analysis.

48. MCC's cost-of-capital witness Hill relied on a similar sample group of proxy companies to which he applied several analytical ROE estimating models to provide a reasonable range of ROE estimates. The methods he relied upon are: 1) a Sustainable Growth Rate-Constant Growth DCF model; 2) a Gordon Growth Rate- Constant Growth DCF model; 3) a Mechanical Growth Rate- Constant Growth DCF model; 4) the CAPM model; 5) a Modified Earnings-Price Ratio model; and 6) a Market-to-Book Ratio model.

49. LCG/FEA's cost-of-capital witness Gorman relied on a proxy group to which he applied several analytical ROE estimating models to provide a reasonable range of ROE estimates including: 1) the Constant Growth DCF model; 2) the CAPM model; and 3) the Utility Risk Premium model.

50. The results of these analyses can be seen below, either listing average and midpoint results, or overall results:

VII: Proposed ROEs

NorthWestern			MCC		LCG/FEA	
Value Line (DCF)	10.5%	11.7%	DCF	7.97–8.87%	DCF	9.00%
IBES (DCF)	10.1%	11.2%	MDCF	8.37%	CAPM	8.60%
Zacks (DCF)	9.9%	10.4%	CAPM	7.2–7.8%	RP	9.70%
Bloomberg (DCF)	9.5%	10.3%	MEPR	7.45–7.65%		
S&P Capital/IQ (DCF)	10.3%	11.5%	MTB	8.72–8.91%		
Fact Set (DCF)	10.0%	11.9%				
Internal br + sv (DCF)	9.4%	11.6%				
Current Bond Yield (CAPM)	10.9%	10.6%				
Projected Bond Yield (CAPM)	11.2%	10.9%				
Current Bond Yield (ECAPM)	11.7%	11.5%				
Projected Bond Yield (ECAPM)	11.9%	11.7%				
Current Bond Yield (RP)	10.0%					
Projected Bond Yield (RP)	11.0%					
Industry (Expected Earnings)	N/A	10.8%				
Proxy Group (Expected Earnings)	10.9%	11.6%				

51. For NorthWestern, considering these results and giving less weight to the extremes at the high- and low-ends, McKenzie concludes that NorthWestern's cost of equity is within a range of 9.8% to 11%. Test. McKenzie at 16 (Sep. 28, 2018). The midpoint within this range is 10.40%. He then adds a 25 basis points adjustment to the midpoint (10.40%) to account for NorthWestern's lack of risk-mitigating regulatory mechanisms and to offset the impact of attrition in arriving at his final recommended ROE of 10.65%. *Id*. Applying the 4.26% cost of long-term debt and the 10.65 cost of equity capital to the capital structure presented by NorthWestern, the resulting after-tax ROR is 7.42%.

52. For the MCC, Hill considers the results of his DCF analyses as his primary indication of NorthWestern's cost of equity. These results, ranging from 7.97% to 8.87%, provide an average DCF ROE estimate of 8.42%. Considering all the evidence presented in his testimony, Hill concludes that the cost of equity capital for a company facing similar risks as NorthWestern ranges from 8.50% to 8.75%. He then considers the following: a portion of NorthWestern's rate base (Colstrip) has already been authorized by the Commission to earn a

ROE (10%) which is higher than the current cost of capital; interest rates are expected to rise which would support an ROE estimate at the upper end of the range; and NorthWestern's lack of risk-reducing regulatory mechanisms as compared to the proxy group would also support an ROE estimate at the upper end of the range. Test. Hill at 75. Considering these factors, Hill recommends an ROE of 8.75%. *Id.* at 76. Applying the 4.26% cost of long-term debt and the 10.65% cost of equity capital to his proposed hypothetical capital structure, the overall after-tax ROR is 6.35%.

53. For the LCG/FEA, Gorman supports a recommended ROE range of 9.0% to 9.70%. His recommendation is that the ROE established in this proceeding should represent the midpoint of that range, 9.35%. Test. Gorman at 3 (Feb. 13, 2019). Applying the 4.26% cost of long-term debt and the 9.35% cost of equity capital to the capital structure presented by NorthWestern, the resulting after-tax ROR is 6.77%.

54. In rebuttal, NorthWestern witness McKenzie argues that the recommended ROEs of Hill and Gorman are below accepted regulatory benchmarks and should be discounted accordingly. Reb. Test. McKenzie at 2 (Apr. 5, 2019). He claims that Hill's recommended ROE of 8.75% "is especially punitive because it would be the lowest ROE allowed for a major vertically-integrated utility in recent history by a wide margin." *Id.* at 2-3. To illustrate his point he provided a table that summarized the average ROEs allowed by all other state Commission's since 2016. *Id.* at 3. The table indicated that during the past three-year period, the average ROE was 9.75%, with a 9.77% average for 2016, 9.8% for 2017, and 9.69% for 2018. This leads McKenzie to conclude that Hill's recommended ROE of 8.75% is 100 basis points below what other regulatory bodies have determined to be just and reasonable, and that Gorman's recommended ROE of 9.35% is 40 basis points below what other regulatory bodies have determined to be just and reasonable. *Id.* Further illustrating his point, he refers to the proxy groups utilized by Hill and Gorman in their ROE analyses and notes that the average authorized ROE for Hill's proxy group is 9.76% and the average authorized ROE for Gorman's proxy group is 9.82%. Reb. Test. McKenzie at 5. He concludes, "[i]t is unreasonable for the Opposing Witnesses to presume that NorthWestern could attract capital for investment at an allowed ROE that falls substantively below the opportunities available from utilities they themselves found were comparable to NorthWestern." *Id.*

55. Additionally, NorthWestern witness Bird notes that "of the 89 discernable ROEs authorized for electric utilities in the last five years…the lowest was 9.1%" and "26% had an ROE of 10% or better." Reb. Test. Bird at 19-20. In addition, he observes that Hill's recommendation mirrors his recommended ROEs for other utilities in Montana (Energy West, MDU) and states that this "appears coincidental and convenient." *Id.* at 19. Given that "[t]hese three utilities [NWE, MDU, Energy West] are significantly different in terms of size, risks, and portion of non-regulated businesses" he questions Hill's conclusion that they would all have the same ROE. *Id.* These three party positions are presented below.

VIII: Proposed RORs

Capital Structure		**Cost**	**WACC**
NorthWestern			
Long-Term Debt	50.62%	4.26%	2.16%
Equity	49.38%	10.65%	5.26%
Overall ROR			7.42%
MCC			
Long-Term Debt	50.10%	4.26%	2.13%
Short-Term Debt	2.65%	3.04%	0.08%
Equity	47.25%	8.75%	4.13%
Overall ROR			6.35%
LCG/FEA			
Long-Term Debt	50.62%	4.26%	2.16%
Equity	49.38%	9.35%	4.62%
Overall ROR			6.77%

iii. ***Commission Finding***

56. The parties stipulated to NorthWestern's proposed capital structure with an overall 9.65% ROE, excluding CU4's continued 10.0% ROE, and subject to a discretionary potential 25 basis point reduction to NorthWestern's ROE dependent on the Commission's decision to authorize a FCRM pilot program. RR Sett. ¶¶ 5-6.

57. Regarding capital structure, NorthWestern proposes to use its actual Montana jurisdictional long term debt and rate base in calculating its capital structure, FEA/LCG does not propose any adjustment to the NWE capital structure, and the MCC proposes the use of a hypothetical capital structure which includes short term debt. The method used by NWE is consistent with past Commission practice and is not opposed by any party other than the MCC. *See* Order 6852f, Dkt. No. D2007.7.82 at 17 (Jul. 1, 2008). The Commission is not convinced by

the MCC arguments that a hypothetical capital structure is preferable in this docket. The Commission finds that the capital structure proposed by NorthWestern is acceptable.

58. Regarding ROE, the proposed ROEs in this docket ranged from a high of 10.65%, proposed by NWE, to a low of 8.75% proposed by the MCC. The FEA/LCG proposed ROE was 9.35%. Paragraph 1 of the RR Stipulation proposes a ROE of 9.65%. The RR Stipulation is silent on how the 9.65% was derived. Based on the Commission's analysis of record evidence in this case, an ROE in the range of 9.2% to 10.0% is fair and reasonable. The 9.65% ROE falls in the middle of the fair and reasonable ranges found in the Commission's analysis and also falls in the middle of the range defined by the parties' respective filed positions. The Commission approves the 9.65% ROE, excluding CU4 which has an approved ROE of 10.0%. The Commission declines at this time to adjust downward the 9.65% ROE as the result of the Commission approval of the FCRM. Overall, the Commission finds that ¶ 5 of the RR Stipulation is approved (ROE and capital structure). Shown below is the 6.92% approved overall ROR for NorthWestern (excluding CU4) approved in this docket.

IX: Approved Weighted Cost of Capital

	Capital Structure	Cost	Weighted Average Cost
Long-Term Debt	50.62%	4.26%	2.16%
Equity	49.38%	9.65%	4.77%
Overall Rate of Return			6.92%

C. Depreciation Expense

i. *General Depreciation*

59. NorthWestern engaged Dr. Ronald White to conduct a 2018 depreciation study for electric and common properties subject to the Commission's jurisdiction. Depreciation rates currently used by NorthWestern for electric and common properties serving Montana customers were adopted during the second quarter of 2013, consistent with a letter of understanding filed with the Commission on July 8, 2013. The implemented rates were developed in a 2012 depreciation study of electric, gas and common utility plant accounts. Current depreciation rates provide for an annual depreciation expense of $89,275,183. The proposed 2018 depreciation study rates provide for annual depreciation expense of $89,961,799. Test. Ronald White at 2 (Sep. 28, 2018).

60. In response, MCC witness David Garrett states that he used the same plant balances as White to develop his proposed depreciation rates. Both Garrett and White have grouped the specific depreciation accounts into plant function. Test. David Garrett at 6 (Feb. 12, 2019). Garrett used the straight line method, the average life procedure, the remaining life technique, and the broad group model to analyze NorthWestern's actuarial data. *Id.* at 11. Garrett states that the majority of depreciation analysts and regulatory jurisdictions rely on the remaining life technique to develop depreciation rates. *Id*. at 12. In Garrett's opinion, "White's approach with regard to manual reserve rebalancing is not in conformance with authoritative depreciation texts or the approach utilized by the majority of depreciation analysts." Test. Garrett at 13. The MCC's adjustments result in an $81,867,505 depreciation accrual, an $8,094,284 reduction from NorthWestern's proposed depreciation expense.

61. Regarding net salvage, Garrett recommends adjustments to two accounts, Account 355 (Poles and Fixtures) and Account 365 (Overhead Conductors and Devices). For Account 355, NorthWestern's net salvage estimate of negative 110% is double the historical net salvage data from the account. Garrett believes that a more reasonable salvage estimate for this account would be negative 90%. This estimate represents a good balance between the average historical net salvage rate observed in this account and the trending net salvage rates observed more recently. Test. White at 32. For Account 365, Garrett believes that NorthWestern's net salvage estimate of negative 100% is incorrect.

62. In response, White states the 2018 study was conducted without any intention of either increasing or decreasing depreciation expense. While Garrett does not claim that the 2018 study was conducted to increase depreciation expense, he should not burden NorthWestern with the burden of proof that no utility could meet. *Id.* at 5. White states the depreciation rate reduction advocated by Garrett produces a reduction of $8.1 million (or about 9.0%) in 2018 annualized depreciation expense from that requested by NorthWestern. *Id.* at 3. In total, White responds that the MCC is: rejecting widely accepted Commission permitted practice of rebalancing recorded depreciation reserves; modifying service-lives or net salvage rates for seven plant accounts; replacing a Commission-approved vintage-group procedure with a broad-group procedure for selected plant accounts; and eliminating amortization accounting. *Id.* Additionally, White observes that "the statistical technique used by Foster Associates is not the same as the 'visual curve fitting' exercise relied upon by Garrett to reduce depreciation

expense." *Id.* at 10. Regarding net salvage, White states that, "Garrett has significantly understated future net salvage rates by examining the wrong historical net salvage data." *Id.* at 12.

63. A summary of the party positions can be found in the table below.

X: Depreciation Accrual Comparison by Plant Function

Plant Function	Plant Balance (12/31/2017)	NorthWestern Accrual	MCC Accrual	MCC Adjustment
Steam Production	$91,523,075	$2,889,378	$2,890,616	$1,238
Hydraulic Production	$517,958,201	$9,280,237	$9,277,523	($2,804)
Other Production	$263,140,036	$10,680,253	$10,715,884	$35,631
Transmission GS-2	$782,164,759	$20,092,856	$15,863,714	($4,229,142)
Distribution	$1,385,048,678	$44,283,866	$40,445,703	($3,838,163)
General	$57,351,329	$2,735,119	$2,674,075	($61,044)
Total	$3,097,186,078	$89,961,799	$81,867,505	($8,094,284)

ii. ***Dave Gates Generating Station Depreciation Rates***

64. The Commission established a straight line depreciation schedule over a 30-year asset life for DGGS. Order 6943a, Dkt. D2008.8.95, ¶ 115 (May 19, 2009). However FEA/LCG witness Brian Andrews challenges NWE's depreciation study for DGGS. Andrews recommends depreciating the DGGS to be retired in 2045, resulting in an operating life of 35 years. Test. Brian Andrews at 13 (Feb 12. 2019). This is the mid-range compared to similar plants according to White. *Id.,* at 11. Andrews also recommends the survivor curve used for Account 343 should reflect 85-SC, which allows for an estimated $16.6 million of retirements through 2045, and is sufficient to account for two major turbine overhauls. *Id.* at 14. The FEA/LCG proposal of Andrews results in a reduction of $1,228,873 to the NWE proposed DGGS depreciation expenses. Test. Andrews at 15.

65. In response, NorthWestern witness Crystal Lail refers to Order 6943a, and disagrees with Andrews because he does not provide sufficient evidence to change the Commission's decision. Reb. Test. Crystal Lail at 12 (Apr. 5, 2019). Lail also states that Andrews did not base the depreciation life on an updated engineering study or alternate evidence as to the life, but rather the mid-point, of a potential range of lives. *Id*. NorthWestern and FEA/LCG's proposed depreciation rates are summarized below.

XI: DGGS Depreciation Rates

Account	NorthWestern	FEA/LCG
341	3.75%	3.10%
342	3.75%	3.10%
343	4.13%	3.38%
345	3.75%	3.09%
346	3.87%	3.19%

iii. ***Stipulation***

66. Paragraphs 7 and 8 of the RR Stipulation addressed depreciation issues:

> ¶7. NorthWestern's proposed depreciation rates, as presented in the testimony of Crystal D. Lail, shall be adjusted to include the extended depreciable lives for NorthWestern's Montana transmission and distribution assets (as proposed by the MCC) and the Dave Gates Generating Station (as proposed by the LCG and FEA), as detailed in Exhibit B.
>
> ¶8. NorthWestern agrees that any future adjustment of NorthWestern's depreciation rates shall require Commission approval.

67. These two provisions result in a reduction to NorthWestern's proposed depreciation expense of $9.3 million, as shown in the following table. RR. Stip., Ex. B.

XII: Summary of Stipulated Depreciation Expense Reductions

Depreciation Expense	Amount
MCC Reduction in Transmission Expense	($4,229,142)
MCC Reduction in Distribution Expense	($3,838,163)
LCG/FEA Reduction in DGGS Expense	($1,228,873)
Total	($9,296,178)

iv. ***Commission Finding***

68. The MCC and the FEA/LCG were the only parties to address depreciation in this proceeding. The Commission's analysis finds that the depreciation adjustments proposed by these parties are reasonable. The Commission approves ¶ 7 of the RR Stipulation and the related adjustments to NorthWestern's proposed depreciation expense.

69. Paragraph 8 of the RR Stipulation results from investigation by the MCC witness Smith, who testified that NorthWestern implemented new, reduced depreciation rates without Commission approval in 2013. Test. Ralph Smith at 17-24 (Feb. 12, 2019). As a result, NorthWestern's test year accumulated depreciation account was understated in its Application by approximately $26.6 million, according to MCC witness Smith. In turn, rate base was overstated by the same amount. Consequently, the MCC proposed a reduction to rate base of $26.6 million.

70. The Commission agrees that utility depreciation rates should be approved by the Commission before they are reflected in utility cost accounting for ratemaking purposes. The Commission approves ¶ 8 of the RR Stipulation.

D. Excess Accumulated Deferred Income Tax Expense

i. ***Background***

71. Excess Accumulated Deferred Income Tax ("EADIT" or "ADIT") is the result of temporary differences between how certain items are treated for regulatory accounting purposes versus how they are treated for income tax purposes. Those differences are created by the use of straight line depreciation for ratemaking versus accelerated depreciation for income tax purposes. For example, years in which deductions (expenses) for income tax purposes exceed actual income tax expense, NorthWestern records a deferred income tax liability. This liability represents revenues recovered by rates that were not paid to the taxing authorities. Eventually, for any single item, that difference will reverse and the regulatory accounting expense will be less than the associated income tax deduction. When this happens, NorthWestern will pay more in taxes than it is recovering in rates. Thus, deferred income tax liabilities are amortized (i.e., reversed) over time. Therefore, ADIT represents NorthWestern's total deferred income tax liability to be paid to the taxing authorities at some point in the future. For ratemaking purposes, deferred income taxes are viewed as a source of zero-interest capital as they have been contributed by customers but have not yet been used for their intended purpose (i.e., to pay income taxes). Because of this, ADIT has permitted utilities to make greater investment in utility plant without having to raise new capital. In addition, ADIT benefits customers because it reduces rate base.

72. Because of the 2017 Tax Cuts and Jobs Act ("TCJA"), which reduced the federal income tax rate from 35% to 21%, a utility will no longer be required to spend its entire ADIT liability balance on income taxes in the future. Because the ADIT liability was accrued assuming future federal income taxes would be paid at the 35% income tax rate and, because of the TCJA, they will only need to be paid at the post-TCJA 21% FIT rate, the 14% difference (35%-21%=14%) becomes excess ADIT ("EADIT") that a utility will no longer be required to pay to the taxing authorities. The EADIT should then be returned to ratepayers.

73. EADIT can be separated into three categories:

a. Protected (Plant/Property) EADIT. This results from accelerated depreciation for income tax purposes. This type of plant/property is subject to Internal Revenue Service ("IRS") normalization requirements, which means that for regulatory accounting purposes it must be depreciated on a straight-line basis but for tax purposes accelerated depreciation is used. 26 U.S.C. § 168. This book/tax difference permits the utility to recover more taxes in rates than they actually pay to the IRS (in the current year), thus creating a deferred tax liability. The IRS requires a public utility to amortize this type of EADIT using the Average Rate Assumption Method ("ARAM") over the life of the Protected Plant.

b. Unprotected (Plant/Property) EADIT. This results from tax timing differences which are not protected pursuant to IRS normalization rules. The Commission approves the amortization period for Unprotected Plant/Property EADIT which consists of items such as tax repair deductions, meter costs deductions, production tax credits, etc.

c. Unprotected Non-Plant EADIT. This results from tax timing differences which are not protected pursuant to IRS normalization rules. The Commission approves the amortization period for Unprotected Non-Plant EADIT which includes deferred gas and power costs, property taxes, customer advances, regulatory assets/liabilities, pension timing differences and other small items.

ii. ***Party Positions***

74. NorthWestern represented that its total unprotected and protected EADIT annual amortization was an increase in deferred tax expense of $387,065. Test. Aaron Bjorkman at 5-6 (Sep. 28, 2018); Stmt. J Work Paper B at 2. NorthWestern calculates the 2018 impact of the Protected Plant EADIT amortization, using ARAM, with a reduction in deferred taxes of ($1,403,791). The amortization period for the two unprotected EADIT categories is at the discretion of the Commission and NWE proposes a five-year amortization, which increases 2018 deferred tax expense for the two categories by $1,790,856.

75. The MCC proposes several adjustments. First, the MCC adjusts the Amortization of Unprotected EADIT for Rate Base items, and removes the EADIT amortization related to Pension Liability items. The MCC asserts that NWE's Pension Liability is not being reflected in rate base and, if it were, it would reduce rate base. Therefore, the MCC states that the related ADIT has been removed from rate base as has the amortization of the related EADIT. This reduces the deferred income taxes by ($1,929,224), equating to a revenue requirement effect of ($2,626,443). Exhibit No.__(RCS-1), Schedule A at 4, column H. Second, the MCC makes two adjustments for the Amortization of Unprotected EADIT for Non-Rate Base items. The MCC

reduces the EADIT by $22,843 by eliminating the EADIT associated with the Contributions Carryover. The MCC asserts that because donations and charitable contributions are not allowed to be included in the cost of service, income tax impacts of such contributions should also be excluded. The MCC also reduces NWE's proposed income tax expense by $430,000 for its Other Comprehensive Income ("OCI") Adjustment. NWE acknowledged, in response to DR LCG-080(d), that the OCI Adjustment was not a cost of service or income statement item and should be removed. These two adjustments reduced the Amortization of Unprotected EADIT for Non-Rate Base items by $452,843, equating to a revenue requirement effect of ($616,500). *Id.*

76. Similarly, LCG makes three adjustments to the Amortization of Unprotected Non-Plant EADIT. First, it excludes the OCI adjustment as referenced in the MCC testimony above. This reduces deferred income tax expense by $430,000. Second, it excludes the EADIT Non-Plant balance associated with Customer Advances for Construction ("CAC"). LCG asserts that while the change in tax rates has resulted in a substantial shortfall related to past CAC payments, it is not reasonable to transfer this cost burden to all customers. CAC payments are designed to hold all other customers harmless, and NWE's proposal to include CAC EADIT violates that principle. The LCG states that NWE calculated a Non-Plant CAC EADIT balance of $4,659,782 amortized over five years. LCG's third adjustment to the Amortization of Unprotected Non-Plant EADIT removes the Pension Liability EADIT balance. LCG states that NWE calculates the EADIT balance associated with the rate based pension liability ADIT is $10,492,083 which NWE proposes to amortize over five years. The LCG makes several technical arguments regarding the accounting for pension expense and why charging customers for the Pension Liability EADIT is not appropriate. KCH Ex. 7–9.

77. In rebuttal, NorthWestern agrees with the MCC and the LCG that the EADIT amortization related to OCI should be eliminated. This increases deferred taxes by $430,000. In addition, NWE agrees with the MCC that the $23,843 in charitable contributions EADIT should also be eliminated. NWE does not agree to the EADIT pension-related adjustments proposed by both the MCC and the LCG. Aaron Bjorkman asserts that because the underlying pre-tax expenses causing these deferred taxes are included in the cost of service for ratemaking purposes, the pension-related EADIT asset should also be recoverable and that if NWE is not allowed recovery of pension–related EADIT, it would not be permitted to recover the full after-tax pension cost of pension expenses. Bjorkman states that NWE does not agree with the LCG to

exclude the amortization of the EADIT CAC balance. First, Bjorkman states that the LCG asserts that the cost causer, not all customers, should bear the costs associated with the taxability of CAC. Bjorkman contends that while correct in theory, it would be impractical to process the deferred tax impact on a customer by customer basis. CAC collections were received at various different points in time and the refundable portion back to customers is often dictated by how many additional customers have joined the extension/improvement. Bjorkman asserts that deferred taxes on CAC are not tracked at the individual customer level, and while some refunds to customers could possibly be accomplished, some customers would not receive a refund and would in theory bear an additional cost previously unknowable after the CAC completion date. He also contends that CAC is a reduction in rate base which benefits all customers, not just the CAC cost causers.

78. The party proposals are summarized below.

XIII: Proposed EADIT Adjustments

Category	Method	NorthWestern	MCC	FEA/LCG	NorthWestern Rebuttal
Protected Plant	ARAM	($1,403,791)	($1,403,791)	($1,403,791)	($1,930,755)
Unprotected Non-Plant Rate Base	5-Year Amortization	$2,864,338	$935,114	($166,035)	$2,888,558
Unprotected Non-Plant, Non-Rate Base	5-Year Amortization	($1,073,482)	($1,526,325)	($1,503,483)	($1,511,714)
Total EADIT		**$387,065**	**($1,995,002)**	**($3,073,309)**	**($553,911)**

iii. ***Stipulation***

79. Paragraph 9 of the RR Stipulation concerns the rate treatment of EADIT as follows:

> ¶9. The Stipulating Parties accept NorthWestern's amount of Excess Accumulated Deferred Income Taxes and amortization as proposed in Aaron J. Bjorkman's rebuttal testimony.

iv. ***Commission Finding***

80. The parties' various annual EADIT amortization range from a $387,065 increase as initially proposed by NorthWestern, to a $3,073,309 reduction as proposed by FEA/LCG. In contrast, the RR Stipulation reflects the ($553,911) annual reduction proposed by NorthWestern

in rebuttal testimony. NorthWestern's rebuttal proposal reflects its acceptance of several adjustments proposed by the MCC and FEA/LCG.

81. Regarding the appropriate amortization period, there are two types of EADIT: *Protected* Plant, which is quantified in the table above, must be amortized using the ARAM under IRS rules; the amortization period for *Unprotected* Plant may be determined by the Commission. NorthWestern proposed a five year amortization period for unprotected EADIT, which was accepted by the MCC and FEA/LCG and is included in the RR Stipulation.

82. The Commission finds that NorthWestern's ($553,911) annual reduction in EADIT amortization is reasonable based on the record.

E. PCCAM Base Costs

i. ***Party Positions***

83. NorthWestern witness Joe Schwartzenberger develops baseline electricity supply rates and associated bill impacts for recovery of electricity supply costs under NorthWestern's Power Costs and Credits Adjustment Mechanism ("PCCAM"). Test. Joe Schwartzenberger at 12-16, Exhibit__ (JS-2) (Sep. 28, 2018). Schwartzenberger applies class loads and line losses to $134,707,594 in base supply costs to design rates. The base supply costs were calculated by Kevin Markovich who testifies that through the PCCAM, NorthWestern will track its actual electric supply costs and credits against the PCCAM Base Costs approved in this docket. Test. Kevin Markovich at 3 (Sep. 28, 2018). He calculates baseline electricity supply costs and credits of $134,707,594 and recommends approval of that amount in this docket. *Id*. at 5. Markovich testifies that the PCCAM base reflects normalized expectation of NWE's actual costs and credits. *Id*. at 3.

84. MCC witness David Dismukes does not directly address the NWE proposed base costs of $134.7 million. Rather Dismukes recommends the Commission adopt a minimum floor for baseline transmission sales of 1.8 MWh per year, based on the historic average from 2013-2017. Test. David Dismukes at 31-36 (Feb. 12, 2019). Dismukes asserts that this will de-risk transmission related credits and ensure that ratepayers are not paying for unnecessary wholesale related transmission investment. *Id.* at 34-35. Dismukes admits that NWE does not track transmission revenue credits in the PCCAM, and that the 1,976,687 MWh reflected in Exhibit__(KJM-1) p. 3 of Markovich's direct testimony are associated with electricity sales and production tax credits rather than transmission sales. DR NWE-037; NWE-039. He also admits

that these volumes are not used to calculate annual transmission revenue credits. DR NWE-040. Dismukes clarifies that "[t]he Company uses its transmission system in part to deliver wholesale sales recovered through the PCCAM to wholesale customers. Setting a minimum floor in the volumes included in the PCCAM base will ensure that ratepayers will continue to receive a minimum financial benefit from wholesale sales even if NorthWestern ceases to find these wholesale opportunities." DR NWE-044.

85. FEA/LCG witness Kevin Higgins asserts that when NorthWestern incorporates the value of production tax credits into the PCCAM base, it is necessary to gross-up this value for income taxes. Test. Kevin Higgins at 27 (Feb. 13, 2019). He asserts that NWE fails to account for tax gross-up and overstates PCCAM base costs. *Id*. at 27-28.

86. In response, Schwartzenberger noted that no party contested NWE's proposed method for designing PCCAM base rates. Reb. Test. Joe Schwartzenberger at 8 (Apr. 5, 2019). In its compliance filing, NWE will compute PCCAM base rates using this method and Markovich's base costs that were revised in rebuttal. *Id*. Markovich describes revisions to PCCAM base rates owing to compliance with Final Order 7563c in Docket D2017.5.39, and to updating historical data and market prices with recent data. Reb. Test. Kevin Markovich at 2-3 (Apr. 5, 2019). In general, Markovich updates five-year historical data from 2013-2017 to 2014-2018, and updates forward market prices from May 2018 to March 2019. *Id*. at 3.

87. In compliance with Order 7563c, Markovich eliminated Category II costs, and moved Category II costs, including QF Tier II and QF-1 Tariff costs to Category I costs. Category II MPSC-MCC taxes are not moved to Category I, but will instead be collected through a deferred account one year in arrears. *Id*. at 8-9.

88. Markovich updates forward market prices to forecasts from March 26, 2019. The forecasts in direct testimony were from May 21, 2018. *Id*. at 4. Forward natural gas prices are based on forecasts from March 26, 2019. *Id*. at 5. He updates on-system market purchases to reflect current volumes and prices, and the new market purchases needed to balance supply and load. *Id*. at 4.

89. The volumes and variable cost forecasts at Basin Creek are now based on 2½ years of data under Reliability Based Control directives rather than the two years of data in direct testimony. *Id*. at 5. DGGS volumes are also updated to a 2½ year period. *Id*. CU4 volumes are based on a five-year availability average in the period from 2014-2018. *Id*.

90. Markovich agrees with Higgins that the base credit for production tax credits should be grossed-up for income taxes. The adjustment is $1,504,568. *Id*. at 7. Markovich calculates that total adjustments increase the base by $3,948,109, from $134,707,594 to $138,655,703. *Id*. at 8.

91. Markovich recommends rejection of Dismukes' proposal to establish a minimum floor for baseline supply sales. *Id*. at 10-12. He testifies that a floor may provide incentive for the utility to buy and resell power that is not needed to meet load in order to benefit from excessive transmission sales, and that an artificial floor violates the spirit and intent of the PCCAM. *Id*.

ii. ***Stipulation***

92. Paragraph 3 of the RR Stipulation addresses the base supply costs and credits used in NorthWestern's PCCAM. Regarding base supply costs and credits, the stipulation states:

> ¶3. Except as provided in paragraph 13, the baseline electricity supply costs and credits for NorthWestern's Power Costs and Credits Adjustment Mechanism shall be as proposed in Kevin J. Markovich's rebuttal testimony.

93. The RR Stipulation adopts the base costs in the rebuttal testimony of NorthWestern witness Markovich. Through the PCCAM, NWE will track actual electric supply costs and credits against the base costs and credits established in this proceeding. The approved base costs and credits will apply to the tracking period beginning July 1, 2019. Reb. Test. Kevin Markovich at 3.

94. In their prefiled testimonies the MCC proposed including a minimum supply sales value as part of the PCCAM base and the FEA/LCG proposed an adjustment of ($1,546,251) for the gross up of Production Tax Credits. Test. Dismukes at 34; Test. Kevin Higgins at 49. In rebuttal testimony, NWE opposed the MCC adjustment and incorporated the LCG adjustment. Rebuttal Test. Kevin Markovich at 10 (Apr. 5, 2019). The RR Stipulation similarly includes the FEA/LCG adjustment, but not the MCC adjustment. The table below summarizes the stipulated base supply costs and credits of $138,655,703.

XIV: Stipulated PCCAM Base Costs

PCCAM Base Cost Summary	
Category One Power Costs	$96,353,668
Category One Power Credits	($34,650,171)
Category Two Power Costs	$76,952,206
Total PCCAM Base Costs	**$138,655,703**

Total Category One Power Costs	
Off-System Fixed Price Purchases	$13,665,600
CU4 Variable Costs	$22,860,046
DGGS Variable Costs	$6,169,172
Judith Gap	$14,946,021
Other Non-QF	$3,622,846
On-System Market Purchases	$16,116,174
NWE Transmission Costs	$2,936,008
Wind Other Costs	$1,615,000
Basin Creek Variable Costs	$2,101,726
Basin Creek Fixed Costs	$5,949,378
Operating Reserves	$1,183,624
INC Purchases	$5,188,073
Sub-Total	**$96,353,668**

Total Category One Power Credits	
Off-System Market Sales	($7,867,369)
On-System Market Sales	($19,578,957)
Spion Kop	($4,238,387)
Hydro Assets	($432,393)
Two Dot	($1,042,974)
YNP Contract Sales	($1,490,091)
Sub-Total	**($34,650,171)**

Total Category Two Power Costs	
GQ Tier II	$33,141,184
QF-Tariff Contracts	$43,811,022
Sub-Total	**$76,952,206**

iii. ***Commission Finding***

95. The only two parties that addressed NWE's proposed PCCAM Base Costs (LCG and MCC) are signatories to the RR Stipulation. Based on its analysis of the proposed Base Costs, the Commission finds the settled value reasonable, and approves the Base Cost amount in RR Stipulation ¶ 3.

F. Fixed Cost Recovery Mechanism

i. ***Party Positions***

96. HRC/NRDC proposed an experimental FCRM pilot that would apply to the residential and GS-1 Secondary non-demand-metered classes for a four-year trial period. The FCRM is intended to decouple NorthWestern's recovery of fixed costs from its sales of energy. HRC/NRDC proposes that test-year fixed transmission and distribution costs allocated to these classes in this proceeding would be used to establish an allowed revenue-per-customer, which would be used to adjust volumetric rates between rate cases based on a comparison of actual revenue to allowed revenue-per-customer multiplied by actual customer counts. Sales volumes between rate cases would not be weather normalized for purposes of determining actual, annual

sales revenue. At the end of the four-year trial period, NorthWestern would be required to make a filing to renew, modify, or terminate the FCRM.

97. Differences between actual fixed cost revenue, from volumetric rates, and allowed fixed cost revenue would be reconciled through a decoupling surcharge or rebate. Accruals would be trued-up annually, with a soft cap of 3% to limit customer impacts (this would limit surcharges or rebates to approximately $2.56/month for average residential customers and $2.00/month for average GS1-Secondary non-demand customers). HRC/NRDC also proposes requiring a third-party audit of the FCRM after three years, customer service and reliability standards, and commitments from NorthWestern to present alternative rate designs such as time-of-use and inclining block rates in its next rate case filing.

98. HRC/NRDC states that the FCRM considers both savings and increased usage per customer, and ensures that customers are not overpaying between rate cases if a utility succeeds in promoting electrification. Hr'g Tr. at 2373-2374. HRC/NRDC states that utilities that adopt decoupling mechanisms such as the FCRM have seen greater cost control, with lower increases in operations and maintenance expenses post-decoupling. With decoupling, utilities earn less than authorized if costs are higher than expected. *Id.* at 2380.

99. MCC opposes the FCRM and argues that if the FCRM is adopted, NorthWestern's ROE should be reduced by 25 basis points. MCC states that if decoupling lowers risk for NorthWestern, then its cost of capital also lowers with decoupling. *Id.* at 2266

100. MCC likens the FCRM to single issue ratemaking, since it adjusts certain fixed costs on an annual basis while other costs remain tied to the historical test year used in the most recent rate case. MCC Resp. Br. at 5-7 (Jul. 31, 2019). MCC also argues that decoupling would reduce NorthWestern's incentive to control costs, as it would guarantee NorthWestern a certain amount of revenue regardless of sales losses. *Id.* at 8-9. MCC believes that NorthWestern is already pursuing a sufficient amount of cost-effective energy efficiency programs, and that no incentives are required. *Id.* at 11.

101. NorthWestern supports the FCRM as proposed by HRC/NRDC; however, NorthWestern witness Bird stated that NorthWestern would not support the FCRM if it were accompanied by any reduction in ROE. Hr'g Tr. at 107. Bird points out that, of the utilities in the region that have adopted decoupling, only Avista has had a reduction in ROE of 10 basis points (Avista adopted decoupling in 2016). *Id.* at 304 (clarified at 363).

102. NorthWestern also suggested the following details regarding the FCRM:

a. The allowed and actual revenues for the FCRM adjustment should not include taxes covered by the annual property tax tracker or PCCAM-related revenues. Reb. Test. Schwartzenberger at 22.

b. The start date for the FCRM pilot should be May 1, 2020, to coincide with the end of peak usage season and to allow for time to complete year-end closing and related-activities before focusing resources on the FCRM filing. *Id.* at 23.

c. Deferred account balances in the FCRM adjustment will consist of the accumulation of the monthly FCRM balances for the months for which actual data is available for the current FCRM year and an estimate of the differences for the remaining months. The balances will also include unamortized balances from prior years including those resulting from estimates and potentially those due to application of the soft cap. *Id.* at 24.

d. The carrying charge applied to the deferred account balances should be the final ordered overall rate of return in this proceeding (excluding the ROR for CU4), until a rate of return is ordered in NorthWestern's next electric rate review. *Id*.

e. The annual FCRM filing should be a compliance filing that includes allowed and actual rate revenues by class and function by month, with estimated data for months where actual data is not available. *Id*. at 25.

f. NorthWestern agrees that an advisory stakeholder group, as recommended in HRC/NRDC response to NWE-129a, should be formed to establish questions and metrics for the third-party audit, assist in the development of the RFP for the FCRM audit, review the RFP responses and provide input on the selection of the third-party auditor, and provide input during the drafting of the audit. *Id.* at 28-29.

g. The cost of the third-party audit should not be capped at $150,000, but should be determined by the scope of the audit and the third-party consultant retained. The advisory stakeholder group and the Commission would have input to the audit costs, and NorthWestern should be allowed 100% recovery of audit costs. *Id.* at 29.

h. Fixed transmission and distribution costs should be adjusted after issuance of a FERC final order to determine allowed revenues for the customer classes under the FCRM pilot. Both the rate and allowed revenue adjustments would be applied from the effective date of the rates established by the FERC final order. *Id.* at 29-30.

103. NWEC supports the implementation of the FCRM with no reduction in ROE, and states that a cost-of-capital study can be done after the pilot period. Hr'g Tr. at 1720.

104. DEQ supports adoption of a pilot FCRM. The Legislature prioritizes acquisition of DSM resources and energy efficiency in statute, and DEQ believes that the FCRM would align customer and utility interest in acquisition of cost-effective DSM. DEQ Resp. Br. at 11-12 Aug. 1, 2019). DEQ supports requiring NorthWestern to propose a residential time-of-use rate in its next rate case regardless of whether the Commission approves the FCRM. *Id.* at 13. DEQ also supports quantitative targets for utility acquisition of cost-effective energy efficiency if the FCRM is approved. *Id*.

ii. ***Commission decision***

105. The Commission finds that a four-year decoupling experiment is reasonable and in the public interest. The Commission has repeatedly encouraged NorthWestern to more fully evaluate DSM options. *See Montana Public Service Commission Comments in Response to NorthWestern Energy's 2015 Electricity Supply Resource Plan*, Dkt. N2015.11.91 (Feb. 2, 2017); and *Comments*, Dkt. N2013.12.84 (May 26, 2015). Additionally, the Montana Legislature has signaled the need for additional encouragement for utilities to adopt DSM measures with the adoption of HB 597 in 2019. HB 597 (effective July 1, 2020). The Commission finds that the FCRM should complement encouragement from the Legislature and the Commission to fully explore cost-effective energy efficiency options.

106. Regarding the MCC's concern that the proposed FCRM shifts risk from NorthWestern to customers, the Commission concludes that both NorthWestern and customers face risk from significant deviations from normal weather, so it is unclear if the FCRM would <u>shift</u> additional weather risk to consumers. *Id.* at 16-17, 30. To the extent changes in economic conditions impact the utility's sales, some business risk may be shifted. However, as changes in economic conditions can also affect the number of customers, and since electricity demand, especially for residential customers, tends to be inelastic in the short run, it is unclear whether any shifted economic risk is significant. MCC did not present evidence of the potential magnitude of shifted risk. *See* the Regulatory Assistance Project's *Revenue Regulation & Decoupling: A Guide to Theory and Application* (2011); referenced in RAP's *Electricity Regulation in the US: A Guide*, Levin Test. at 5, footnote 1.

107. MCC is also concerned that decoupling abandons test period ratemaking and violates the "matching principle". However, under the proposed FCRM, allowed revenue recovery is matched to test-year cost of service and billing determinants from the most recent

rate case; the fixed-cost-per-customer rate, which determines allowed transmission and distribution revenue, would not adjust between rate cases based on any changes to fixed costs or revenue examined in the rate case.

108. Nor is the Commission convinced that incentives for NorthWestern to control costs would be reduced, as evidence in the record does not demonstrate this outcome for electric utilities that adopted decoupling. Additionally, the basis for NorthWestern's allowed revenue between rate cases remains linked to rates based on test-year cost of service, so the impacts of regulatory lag also remain. As increases in energy sales between rate cases would not be a way to increase earnings with the FCRM, focus on cost control may, in fact, increase.

109. The Commission declines to adopt a reduction to the authorized ROE at this time. The stipulated ROE is reasonable because it is based—at least in part—on the observable market data of similarly-situated utilities (i.e., proxy groups). NorthWestern demonstrated that roughly two thirds of the proxy groups used in its analyses have either full or partial decoupling mechanisms. Ex. AMM-3 (Sep. 28, 2018). Similarly, roughly two-thirds of the proxy groups used by FEA/LCG and one-third of the proxy groups used by MCC have either full or partial decoupling mechanisms. Ex. AMM-3 and Ex. MPG-3 (Feb. 13, 2019), Ex. AMM-3 and Ex. SGH-2 (Feb. 12, 2019).

110. The Commission is not convinced that a reduction in weather-related risk translates directly to a reduction in NorthWestern's cost of capital. While NorthWestern's book-value earnings may be less volatile as a result of decoupling, it is premature to conclude that this reduction in book-value risk would automatically translate to the capital markets. The Commission finds that it is appropriate to revisit any increase or decrease in cost of capital after the pilot period concludes. At that time, the market and its participants will have had time to respond to the FCRM. Because any decision by the Commission at that time would be based on observable market data, any ROE adjustment would not be bound by the 25-basis-point parameter defined in the RR Stipulation.

111. The annual true-up of actual and allowed fixed cost revenue should occur when other true-up mechanisms may result in rate adjustments in the opposite direction (e.g., the PCCAM). Therefore, the Commission finds that it is reasonable to have the annual FCRM adjustments coincide with NorthWestern's PCCAM filing. The first FCRM adjustment should

coincide with the PCCAM adjustment filing in September of 2021, and will apply to the period of July 1, 2020, through June 30, 20201.

112. The Commission approves the FCRM pilot as proposed by HRC/NRDC, without any reduction in ROE. The Commission directs NorthWestern to provide a compliance filing, including a tariff schedule for the decoupling adjustment. This compliance filing should include the relevant calculations to determine the actual and allowed annual fixed cost revenue, details of how the performance metrics approved by the Commission will be reported, and a description of the billing metrics for how the FCRM rates will appear on customer bills. Additionally, the FCRM pilot shall adhere to the following conditions:

a. NorthWestern will submit a third-party audit of the FCRM to the Commission after a three-year period. The audit shall include an evaluation of energy efficiency and peak-demand reduction measures, including how any measures have changed since the adoption of the FCRM pilot. The audit shall also include an analysis of the FCRM's impact on observable market data to determine any impact of the FCRM on NorthWestern's cost of capital.

b. NorthWestern must file a rate case before the end of the four-year pilot to renew, modify, or terminate the FCRM. The rate case at the end of the pilot period shall include an analysis of time-of-use rates and other alternative rate designs such as inclining block rates, in addition to any rate designs NorthWestern chooses to propose. If NorthWestern files a rate case at any time prior to the completion of the pilot period, it must include justification as to why the FCRM should be continued or discontinued.

c. The Commission reserves the authority to order a review of the FCRM at any time, should it feel that the mechanism is not operating as intended.

d. The Commission adopts the customer service and reliability standards proposed by HRC/NRDC.

e. NorthWestern's clarifications for the FCRM are approved, with the exception of the adjustment date in part b. Instead, the FCRM filing should coincide with NorthWestern's annual PCCAM filing.

G. 2018 Property Taxes

113. The parties stipulated to the inclusion of property tax revenue resulting from Docket D2018.11.80. RR Stip. ¶ 4 ("The settlement rate increase is incremental to $7,463,894 of property tax revenue reflected in rates effective January 1, 2019, pursuant to Docket No. D2018.11.80. Therefore, the rates shown in Exhibit A to the Amended Stipulation do not reflect those changes to rates. If the Commission approves this Amended Stipulation, the resulting electric customer rates would be the rates shown in Exhibit A to the Amended Stipulation,

adjusted for any changes to final rate design approved by the Commission, plus the rate increases approved in Docket No. D2018.11.80 to reflect 2019 estimated property taxes. For purposes of future property tax tracker filings, the base level of property taxes from this rate case shall be the actual level of property taxes in 2018.”).

114. The RR Stipulation recognizes that the stipulated $6.5 million revenue requirement increase is incremental to a $7,463,894 property tax tracking rate adjustment effective January 1, 2019, and that the base level of property taxes for future property tax trackers should be actual property taxes in 2018. Notice of Commission Action (Nov. 6, 2019). NWE filed its December 7, 2018, tax tracker for 2019 rates in Docket No. D2018.11.80. The tax tracker rate increases were effective January 1, 2019. NWE’s original Application in this case was filed September 28, 2018. NWE subsequently filed its rebuttal testimony on April 5, 2019. The total revenues shown in the rebuttal exhibits of NWE did not include the January 1, 2019, property tax increase. Reb. Test. Glenda Gibson. Exh GJG-6 at 8 (Apr. 5, 2019) (used in this Order to establish the NWE Electric Utility Total Revenue Requirement).

115. The $6.5 million increase in rates, as the result of approval of the RR Stipulation, is incremental to the tax tracker rates, and the Commission approves ¶ 4 of the RR Stipulation.

H. Colstrip

i. *Stipulation*

116. Paragraph 11 of the RR Stipulation states:

> ¶11. With the exception of the functionalization of the Regulatory Plant Adjustment, the Stipulating Parties accept the Colstrip Unit 4 revenue requirement as proposed by NorthWestern.

ii. *Commission Finding*

117. NorthWestern’s total electric utility revenue requirement can be segregated into four key elements: transmission and distribution, generation, Two Dot, and base net power supply costs used in the PCCAM. Test. Gibson at 3. The level of base costs for the PCCAM can be distinguished from the other elements of the revenue requirement as it does not involve any rate base. As shown below, NorthWestern’s Application requested approval of three separate revenue requirements.

XV: NorthWestern's Revenue Requirement Summary

Revenue Requirement	Initial	Rebuttal	Difference
Trans. & Dist.	$37,912,136	$35,565,427	($2,346,709)
Total Generation	($3,045,760)	($4,859,110)	($1,813,360)
Two Dot	($4,656)	($4,656)	$0
Total Electric Utility	**$34,861,730**	**$30,701,661**	**($4,160,069)**

118. As described above, in its rebuttal testimony NorthWestern proposed a reduction to the total generation revenue requirement of ($4,859,110), which is comprised of the six component revenue requirement changes listed in the following table.

XVI: Stipulated Changes to Generation Revenue Requirement

Category	Rebuttal Generation Revenue Requirement	Stipulation Revenue Requirement	Difference
CU4	($10,425,834)	($10,425,821)	$0
DGGS	$1,796,014	N/A	N/A
Spion Kop Wind	($146,794)	N/A	N/A
Hydroelectric Assets	$532,510	N/A	N/A
Montana Generation	$797,949	N/A	N/A
Non-PCCAM	$2,587,045	N/A	N/A
Generation Excluding CU4	$5,566,841	($1,488,564)	($7,055,405)
Total Generation	**($4,859,110)**	**($11,914,385)**	**($7,055,274)**

119. The Commission approves the $6.5 million revenue requirement increase in the RR Stipulation which includes the ($11,914,385) reduction to the total generation revenue requirement. The RR Stipulation does not contain a breakdown of how that reduction impacts each of the component revenue requirements, although ¶ 11 indicates the parties "accept" the CU4 revenue requirement proposed by NorthWestern. The RR Stipulation reduces the overall generation revenue requirement by an additional ($7,055,274) compared to NorthWestern's rebuttal testimony. Since the RR Stipulation specifies that the parties accept NorthWestern's rebuttal CU4 revenue requirement, the ($7,055,274) reduction in the total generation revenue requirement must come from changes to the revenue requirements of the other five components, although those changes are not specified.

120. A similar situation arose in NorthWestern's last natural gas general rate case, Docket D2016.9.68. In that case, NorthWestern had three gas production assets: Battle Creek, Bear Paw (NFR), and Bear Paw (Devon). In that case, the Commission consolidated the three

individual gas asset revenue requirements into one revenue requirement called the production asset revenue requirement. Dkt. D2016.9.68, Order 7522g ¶¶ 51-52, (Aug. 15, 2017). There was a stipulation filed in this docket on May 5, 2017 between NWE and the MCC which set the Phase I revenue requirement for natural gas utility delivery service and production service. There were no revenue requirements established for each individual production asset.

121. The Commission refrains from making a decision on the CU4 revenue requirement for two reasons. First, the proposed change in the Generation revenue requirement is in a range of -$21.4 million to -$4.9 million. Based on that range, the Commission finds that the proposed change of -$11.9 million for the total Generation revenue requirement is reasonable. However, based on the record and in the context of the RR Stipulation, the Commission is unable to find that NorthWestern's proposed CU4 revenue requirement is either reasonable or unreasonable. It is neither appropriate nor necessary to selectively approve a single element of the overall generation revenue requirement in order to assess whether the RR Stipulation results in just and reasonable rates. If the Commission approves the total revenue requirement increase, and the specified adjustments to the transmission and distribution and generation revenue requirements in ¶ 1 of the RR Stipulation, there is no further need to approve any of the individual components of the generation revenue requirement. Second, because the settlement language regarding the Colstrip rate base valuations is merely an agreement between the parties to accept the CU4 revenue requirement change, the Commission determines no further action was required.

122. Accordingly, the Commission approves the overall Transmission and Distribution and Generation Revenue Requirements agreed-to in the settlement. This revenue requirement, in addition to NorthWestern's rebuttal, and the MCC and FEA/LCG's proposed revenue requirements are provided for context.

XVII: Generation and T&D Revenue Requirements

Party	T&D	Generation	Two Dot	Total
NorthWestern Rebuttal	$35,525,427	($4,859,110)	($4,656)	$30,701,661
MCC	$4,377,047	($21,432,482)	($365,383)	($17,320,818)
FEA/LCG	$12,785,504	($15,706,634	N/A	($2,921,130)
Stipulation	$18,414,385	($11,914,385)		$6,500,000

I. Two Dot Acquisition

123. In its initial Application, NorthWestern requested that the Commission authorize the inclusion of Two Dot Wind Farm in rate base and the proposed revenue requirement in base rates. NorthWestern App. at 5 (Sep. 28, 2018).

124. NWE witness Bleau LaFave presented testimony regarding the acquisition of the Two Dot Wind Farm. LaFave testifies that Two Dot is a wind farm located in Wheatland County, approximately six miles west of Harlowton, Montana. It consists of six General Electric ("GE") 1.6 MW, XLE turbines totaling at the time of contracting, 9.72 MW of nameplate capacity. Two Dot connects directly to NWE's transmission system and, prior to NWE's purchase, sold its output to NWE as a QF. LaFave states that, prior to the purchase, NWE has recovered its Two Dot costs by including them as QF power purchases in its electric tracker dockets. Test. Bleau LaFave at 2 (Sep. 28, 2018).

125. Since it began commercial operation on June 19, 2014, Two Dot has had a net capacity factor of 36.82%, or annual average production of 32,585 MWh. GE has maintained the turbines through a Facilities Maintenance Agreement. NWE is not aware of any issues related to Two Dot's operations and maintenance history. *Id.* at 3.

126. Regarding NWE's contractual obligations for the purchase of power from Two Dot, NWE executed the original PPA on August 19, 2011, which included a commercial operation date ("COD") of December 31, 2012, with a 25-year term following the COD at a rate of $59.00/MWh. This rate was based on the rate that existed in the Commission-approved rate set forth in NWE's Electric Tariff, Schedule QF-1.

127. On January 2, 2013, NWE executed an amendment to the original PPA, changing the COD to December 31, 2013, and adding a provision giving NWE a Right of First Refusal ("ROFR"). The ROFR provision required the seller to offer to sell Two Dot to NWE under the

same terms and conditions as offered by a third-party buyer before it could sell the facility to the third-party buyer.

128. On May 16, 2014, NWE executed another amendment to the original PPA. Two Dot requested the second amendment to transition from the original rate of $59/MWh to an equivalent tiered rate of $49/MWh for the first 10 years of the PPA and $75.78/MWh for the remaining 15 years. The second amendment also changed the seller's information to reference NJR Clean Energy Ventures II Corporation ("NJR"). *Id.* at 4.

129. On November 27, 2017, NJR notified NWE that the ROFR provision in the PPA had been triggered and that NWE had 30 days, or until December 27, 2017, in which to either accept or decline to buy Two Dot at the purchase price of $18.5 million.

130. LaFave explained, in analyzing the purchase, NWE modeled the costs and benefits of NWE owning Two Dot versus continuing with the PPA purchases, with a specific focus on comparing the costs of ownership versus the cost of the remaining payments NWE was legally obligated to make under the PPA. In addition, NWE conducted due diligence on the facilities that included review of environmental issues, operational issues, land and easements, technology, regulatory matters, and other potential contractual obligations. The results of the purchase evaluation were that the purchase had benefits for both customers and NorthWestern. Based on that evaluation, NWE notified NJR that it accepted the offer to purchase Two Dot for $18,541,706, or $1,907,582/MW.

131. LaFave testifies that NWE received FERC's approval for the purchase in May 2018, and the purchase closed on May 31, 2018. NWE took operational control on June 1, 2018, and then rolled the asset into its parent company, NorthWestern Corporation. Since June 1, 2018, Two Dot has operated as expected and NWE has not experienced any issues and the facility is producing similar to previous years. *Id.* at 10.

132. After the purchase was complete, NWE requested, and the Commission approved, recovery of the costs of owning Two Dot on an interim basis in its annual electricity supply tracker in Docket No. 2017.07.057, Interim Order No. 7606. The interim bridge rate is equivalent to the QF PPA rate of $49.00/MWh for the output of Two Dot until a new rate is established in this case. NWE proposed that if the new approved rate is lower than $49.00/MWh, the interim rate be trued-up to the approved rate and the over-collection refunded to customers; if the

approved rate is higher than $49.00/MWh, the interim rate be approved as final. Test. LaFave at 15.

i. ***Commission Finding***

133. No party to this docket contested the inclusion of Two Dot in rate base or the revenue requirement in base rates. The overall impact of the purchase has been simply to reclassify Two Dot QF costs in the monthly electric supply tracker to Two Dot fixed costs in the same tracker, with no overall change in rates or customer impact. The change in the total electric utility revenue requested by NorthWestern was an increase of $30,701,661. The revenue requirement filed for Two Dot shows a required reduction in its total revenue requirement of ($4,656), a *de minimis* change. *Id.* at Exh. GJG-7. The Commission approves NorthWestern's request to include Two Dot wind in rate base and its revenue requirement in base rates.

134. Additionally, NorthWestern requested a fixed revenue requirement for Two Dot of $2,732,522 and variable rate Production Tax Credits ("PTCs") of $1,706,359 for a net revenue requirement of $1,706,359. *Id*. at 14. Dividing the net revenue requirement by the annual production of 32,585 MWh yields a Two Dot rate of $52.37/MWh. Per the testimony of LaFave, because the rate of $52.37 is higher than the interim bridge rate of $49.00/MWh, the Commission approves as final the interim bridge rate approved in Interim Order 7606.

J. FERC Transmission Revenue Credits

135. NWE proposes to continue to follow precedent established by Commission approval of electric utility revenue requirements in which NWE files 100% of its Montana transmission system costs in its revenue requirement calculations made at both the FERC and the Commission. *See* Dkt. D2007.7.82, Order 6852F; and Dkt. D2009.9.129, Order 7946h. The FERC regulates rates and services for electric transmission and electric wholesale power sales in interstate commerce. The FERC calculates transmission rates for customers taking service under the FERC Open Access Transmission Tariff ("OATT"). The Montana jurisdictional revenues generated under the OATT tariff are then credited against the Montana revenue requirement.

136. NWE filed a transmission revenue requirement application with the FERC on May 1, 2019. FERC Docket Nos. ER 19-1756-000, EL 18-104-000 The FERC revenue credit filed in this docket is $54,245,506. Reb. Test. Gibson at Exh. GJG-6. NWE states that once FERC issues a final order in response to NWE's application, NWE proposes to true-up the revenue credit in this proceeding, effective upon the rate-effective date established in the FERC

final order. NorthWestern would apply the updated FERC rates to the transmission volumes that were the basis for the normalized revenue credits in this proceeding. Test. Michael Cashell at 17, 20 (Sep. 28, 2018).

137. The Commission approves the continuation of the FERC revenue credit methodology as approved in previous dockets. NWE must file with the Commission the adjusted FERC revenue credit and proposed rate design such that required rate changes to Rate Schedule Revenues shall be effective within 60 days of the final FERC order. In addition, NorthWestern shall true-up the FERC revenue credit for the period from the July 1, 2019, FERC refundable rate effective date until the date adjusted MPSC rates go into effect. Any over- or under-collection will be refunded to, or collected from, customers over a one-year period.

K. Hazard Tree Removal Program

138. The Commission is extremely cognizant of the wildfire nightmare which has unfolded in California over the last several years leading to disastrous loss of life and property. The Commission is concerned about how a wildfire involving utility equipment and hazard trees due to pine beetle kill could lead to a similar situation and associated risks to NWE and its customers in Montana.

139. On January 29, 2019, Pacific Gas and Electric ("PG&E) filed for bankruptcy to deal with billions of dollars in wildfire liability. The following is from the January 14, 2019, *New York Times* article:

> Fire investigators determined PG&E to be the cause of at least 17 of 21 major Northern California fires in 2017. It is also suspected in some of the 2018 wildfires that have been described as the worst in state history, including one that killed at least 86 people and destroyed the town of Paradise.
>
> PG&E said it faced an estimated $30 billion liability for damages from the two years of wildfires, a sum that would exceed its insurance and assets. The bankruptcy announcement, in a filing with federal regulators, led the company's shares to plunge more than 50%.
>
> The shares had already lost almost two-thirds of their value since a wave of wildfires in early November, and its bond rating had been downgraded to junk status by two rating agencies.

140. The wildfires in California have led to catastrophic property losses and loss of life, and the bankruptcy of the largest utility in the State. To avoid that situation in Montana, NWE witness Curtis Pohl addressed the hazardous tree issue in his direct testimony. Pohl

testified that the Mountain Pine Beetle ("MPB") infestation in Montana has impacted NWE's system for quite some time. Pohl states that as part of its normal vegetation management program, NWE routinely removes trees from within its rights-of-way. However, by 2016, NWE realized that, given the sheer number of MPB-impacted trees found outside of its rights-of-way, NWE needed to find a solution beyond the scope of its normal vegetation management plan to address this risk. Test. Curtis Pohl at 11-12 (Sep. 28, 2018).

i. ***Party Positions***

141. Pohl testifies that NWE began working with the appropriate groups, including the U.S. Forest Service, to develop a plan to remove these hazard trees. NWE identified approximately 1,030 miles of transmission and distribution lines as severely impacted by the MPB. NWE determined that the only way to mitigate fire and reliability risk along these miles was to clear-cut all of the trees on either side of the electric lines that could hit the lines, if they fell. In most cases, this amounts to approximately 100 feet on either side of the lines or a 200-foot-wide corridor. Pohl states that normal rights-of-way vary, but are generally 20 feet to 40 feet wide on distribution lines and 40 feet to 100 feet wide on transmission lines. NWE's plan to address these 1,030 miles was not finalized until the first quarter of 2018, and work started in April 2018. NWE's initial plan is estimated to cost $18.5 million and take three years to address the immediate concern of the 1,030 miles. However, NWE expects to be dealing with this hazard tree issue for quite some time beyond that. The MBP, along with other infestations, will continue to affect more areas, and NWE's vegetation management crews will need to make multiple trips through these areas to remove trees as they become hazard trees. *Id*. at 16 (other hazardous infestations include Spruce Bud Worm or the Douglas Fir Beetle). Pohl states this will be an ongoing effort until NWE can clear-cut all of the hazard trees that threaten our lines.

142. NWE has proposed a revenue requirement adjustment to include $3.5 million annually for hazard tree removal to mitigate the potential for disastrous wildfires. Test. Glenda Gibson, Ex. GJG-1 at 4 Column Q.

143. On November 9, 2018, the MCC, the LCG, HRC/NRDC, and the MEIC/NWEC filed a settlement agreement in the Commission's investigation of the TCJA and NorthWestern Energy. Page 5, Section e. of the settlement agreement stated:

> In Docket No. D2018.2.12, Northwestern has proposed an expense adjustment of $3.5 million in the test period for hazard tree removal, as a known and measurable change based on the total estimate 2018 spending. In Docket No. D2018.2.12, the

> Stipulating Parties other than Northwestern agree not to oppose an adjustment for known and measurable change equal to actual 2018 expenditures for hazard and tree removal not to exceed $3.5 million.

144. In response to MCC-247, NWE indicated its 2018 actual expenditures on hazard tree removal were $3,190,879.

145. The Commission issued a Notice of Additional Issues on March 1, 2019, which asked parties to address several issues regarding hazardous tree mitigation and potential liability. Importantly, the Commission asked NWE if it is able to insure itself and ratepayers against the risk posed by wildfire liability.

146. Regarding insurance, NWE states that it purchases a tower of liability insurance, currently totaling limits of $300 million for all liability. NWE's liability insurance includes coverage for wildfire liability. The total premium for that insurance is $4,395,576 for the July 2018 to June 2019 policy period. NWE's primary insurance carrier is AEGIS. Four excess carriers provide NWE coverage over the limit that AEGIS insures. During the 2018 renewal, NWE and AEGIS negotiated an endorsement that allows a depleted aggregate to be replenished for a pre-determined price. That is, NWE may elect to add a second wildfire limit, if there is a large loss. To Brian Bird's knowledge, NWE is the only utility that has negotiated this additional coverage with AEGIS. In recent conversations, AEGIS representatives gave expressed caution about wildfire risks, but indicated that it is not reducing coverage at this time. Addl. Issues Test. Brian Bird at 5-6 (Mar. 22, 2019).

147. Bird states that regarding the situation in California where PG&E has said that it faces an estimated $30 billion liability for two years of wildfires, NWE considers additional liability insurance every year. However, with California fire losses, wildfire coverage has become less available and more expensive. As part of its insurance renewal process, which is just starting, NWE represented it is going to pursue purchasing higher limits. Bird states that NWE has already been notified that one of its excess carriers is reducing its offered limits for all utilities with wildfire risks. NWE asserts that, given the losses in California, it may be difficult to continue to replace much less increase the limits that NWE purchases for wildfire coverage. *Id.*

ii. ***Commission Finding***

148. No party to this docket has opposed expenditures for the Hazard Tree Removal Program. As described above, several parties in this docket are on the record as not opposing further spending not to exceed the actual amount spent in 2018.

149. The stipulated revenue requirement increase of $6.5 million in this docket is a "black box" settlement. That is, there is no information available to the Commission regarding whether the final stipulated revenue requirement for the NWE Electric Utility included any agreement regarding the Hazard Tree Program. The Commission is cognizant of NWE's past efforts to address the hazard tree dangers in its service territory and is also aware of the plans to continue those efforts in future years.

150. Because of the significant importance of the Hazard Tree Program to both NWE and the health and safety of Montana residents, the Commission orders NWE to continue its Hazard Tree Program with minimum annual expenditures equal to the $3.2 million spent in 2018. The Hazard Tree program is to be funded out of the revenue requirement approved by the Commission on October 30, 2019, where NWE was granted a $6.5 million increase in its total revenue requirement. The Commission also orders NWE to present to the Commission, no later than 90 days after the issuance of the Final Order in this docket, the current status of its Hazard Tree Program and its future plans for 2020 and beyond. NWE shall file annual program progress updates, including annual expenditures, no later than January 31 of each year beginning in 2021.

L. Total Revenue Requirement & Refund

151. The ultimate result of a revenue requirement proceeding is to establish the Total Revenue Requirement of the utility. The table below indicates the total NorthWestern Revenue Requirement as approved by the Commission in this docket. The Total Rate Schedule Revenue Requirement of $541,443,921 reflects the total revenues impacted by the $6.5 million revenue requirement increase approved in this docket. The Total Revenue Requirement reflects the revenues used to calculate the overall return in this docket. The primary component of the $59,394,921 in Other Revenue is the FERC Revenue Credit of $54,245,506. A probable change in the FERC Revenue Credit amount in 2020, as discussed previously in this Order, will require a corresponding change in the Rate Schedule Revenue Requirement.

XVIII: NorthWestern's Total Electric Utility Revenue Requirement

As Filed Adjusted 2017 Test Year	T&D	Generation	Two Dot	Total Excluding PCCAM
Rate Schedule Revenues	$263,531,298	$261,216,207	$2,732,522	$527,480,027
Sales for Resale	$108,861			$108,861
Transmission (FERC Revenue Credit)	$54,245,506			$54,245,506
Miscellaneous Revenues	$3,492,605	$1,547,144		$5,039,749
Gross Revenues	**$321,378,270**	**$262,763,351**	**$2,732,522**	**$586,874,143**
Rate Schedule Revenues Adjusted for Property Tax & $6.5 million increase				
Rate Revenues Without Stipulated Change	$263,531,298	$261,216,207	$2,732,522	
May 12, 2019 Amended Stipulation	$18,414,385	($11,914,385)		$6,500,000
Stipulation Rate Revenue Requirement	$281,945,683	$249,301,822	$2,732,522	$533,980,027
Jan. 1, 2019 Property Tax Increase	$6,723,259	$740,635		$7,463,894
Total Rate Schedule RR	**$288,668,942**	**$250,042,457**	**$2,732,522**	**$541,443,921**
Other Revenue Items	$57,846,972	$1,547,144	$0	$59,394,116
Total Revenue Requirement	**$346,515,914**	**$251,589,601**	**$2,732,522**	**$600,838,037**

152. On March 3, 2019, the Commission authorized NorthWestern to collect on an interim basis an additional $10,544,411 annually in electric revenue based on a ROE of 9.8%. Order 7604r. This increase was attributed solely to delivery service rates. *Id.* ¶ 6. The interim rate increase resulting from the RR Stipulation is $4,044,411 less than the interim rates that took effect April 1, 2019.

153. By February 29, 2020, NorthWestern will have collected approximately $3.74 million of this amount since April 1, 2019. The Commission directs NorthWestern to refund to customers the difference between the current amount collected in interim rates that have been in effect since April 1, 2019, and the final rates approved in this docket that will take effect March 1, 2020, with 9.80% interest. This refund should be credited to customers monthly, over a one-year period beginning from the effective date of rates approved by the Commission in this

decision. The un-refunded balance shall continue to accrue interest at 9.80%. This will result in a reduction of approximately $0.46 per month in the typical residential bill.

II. Cost Allocation and Rate Design

A. Cost Allocation

i. *Party Positions*

154. NorthWestern witness Schwartzenberger introduced NorthWestern's moderated cost of service allocations and rate design proposals. Test. Schwartzenberger at 3. Embedded and marginal cost studies ("ECOS" and "MCOS") were provided by Normand, with details of the studies provided in Statement L. Test. Paul Normand at 1-2 (Sep. 28, 2018). Normand did not rely on his MCOS results as a basis for his cost allocation and rate design proposals. *Id*. at 5-6.

155. Normand allocates the cost of production plant according to monthly generation in 2017, based on the proportion of each customer classes' monthly sales adjusted for losses. *Id*. at 12. Normand allocates transmission costs using a simple average of class contributions to monthly coincident peaks. *Id*. at 13. He allocates primary and secondary distribution costs using monthly non-coincident peak ("NCP") contributions. *Id*. at 13-14. He allocates the cost of meters and services based on the typical cost per customer including installation for each rate class. *Id*. at 14-15. This estimate is multiplied by the number of customers to find a total cost for each class. The allocation factors are the ratios of class cost to total meter and service costs for all classes. *Id*. Normand allocates customer service costs using an average factor weighted 75% to customer numbers and 25% to sales. *Id*. at 15.

156. Normand moderates the uniform rate of return allocations in his class cost of service study to find proposed class allocations that may be used to design rates. His moderation algorithm includes: 1) limiting the revenue increase to 10% for any class; and 2) recovering the consequent shortfall from all classes that would receive a decrease under uniform rate of return, except for the GS-2 Transmission class, which was held constant due to its excessive rate of return in the cost of service study. *Id*. at 45-47.

157. In contrast, MCC witness Dismukes disagrees with Normand's cost of service NCP allocation of distribution plant, because Dismukes believes the allocation places too much emphasis on localized peak loads. Test. Dismukes at 44-46. Instead Dismukes recommends a 50/50 weighting of NCP and coincident peak ("CP") demands, and that the rate increase to any customer class be limited to 1.25 times the increase to the revenue requirement. *Id*. at 45, 56.

This limits the maximum revenue increase to any class to 8.26%, compared to NorthWestern's proposed maximum increase of 10%. *Id*. Dismukes also recommends that the Commission hold rates constant for all classes currently over-earning, rather than NorthWestern's proposal to freeze rates for only one class, the GS-2 Transmission class. *Id*. Dismukes presents his allocations under the proposed NorthWestern increase to revenue requirement in Exhibit DED-7. *Id*. at 57.

158. Similar to the MCC, FEA/LCG witness Higgins contests Normand's allocation of distribution poles, conductors, and transformers at 100% to NCP demand, arguing that the cost of these items has a significant customer component. Test. Higgins at 33. Higgins asserts that the NARUC cost allocation manual supports a partial customer allocation of these costs, and recommends that NorthWestern file a minimum system or zero intercept study, as described in the NARUC manual, in its next general rate filing. *Id*. at 35.

159. Higgins contests Normand's allocation of customer service expenses 75% to customer numbers and 25% to energy usage. He sees no rationale for assigning any of these expenses to energy determinants, and proposes allocating 100% to customer numbers. *Id*. Higgins also disputes Normand's allocation of generation plant entirely to energy usage. He believes this allocation should consider the capability of generation plant to meet system peak demands. *Id*. at 36. Higgins recommends allocating generation plant using either a 12-CP method or an Average and Excess demand method. *Id*. at 37-38. Higgins uses an Average and Excess Demand allocation in this proceeding because it allocates a portion of plant to energy usage. *Id*. at 38.

160. Higgins also expresses concern that due to moderation guidelines, Normand's moderated allocation of costs to class results in a draconian increase to Choice customers. *Id*. at 41. For instance, the increase to the GS-2 Substation Choice class is 37.95%, even though Normand's cost of service study suggests an increase of only 3.87%. *Id*. at 41-42. Under Normand's allocation, the GS-2 Substation Non-Choice customer class receives an 8.24% decrease. *Id*. at 42. The difference in allocation to GS-2 Substation choice and non-choice customers is due to the decrease in generation costs relative to transmission and distribution costs. *Id*. Since Higgins believes the increases to Choice customers above cost are due to the attempt to restrict increases to other classes to 10% and to prevent large increases to the allocations of Choice customers, Higgins recommends that rates for each rate schedule should be

set equal to cost, with one adjustment to moderate the impact to the irrigation class. *Id*. at 43-44 (Higgins recommends that the increase to Irrigation be limited to one-half of the cost based increase).

161. While Higgins believes that his own cost of service study, as shown in Exhibit KCH-18, represents cost allocations to class most accurately, in the interest of gradualism he recommends that the Commission adopt Normand's cost of service study to allocate costs to classes. *Id*. at 45. He recommends that Normand's study be corrected for errors that Higgins discovered. *Id*. at 8, 45; Exhibit KCH-21. Higgins presents his recommended allocations at NorthWestern's proposed revenue requirement in Exhibit KCH-19.

162. Walmart does not oppose NorthWestern's proposed cost of service class allocations at its proposed revenue requirement. Test. Steve Chriss at 4 (Feb. 12, 2019). If the Commission finds that a reduction to NorthWestern's proposed revenue requirement is warranted, Chriss proposes that 50% of the reduction be applied to reduce allocations to the subsidizing classes in equal proportion, and the remainder be applied to reduce the proposed increases in allocation to all classes, provided that no subsidizing class moves to subsidized. *Id*. at 4-5. Walmart also proposes that demand rates for the GS-1 Secondary Demand class be increased to recover all of NorthWestern's proposed increase to the GS-1 Secondary Demand allocation, even if the Commission approves a lesser allocation. *Id*. at 5. Chriss testifies that according to NorthWestern's methodology, all distribution costs are allocated to demand, with none of these costs allocated to energy. *Id*. at 14. Because only 79% of distribution costs for this class are currently recovered through demand charges, higher load factor customers are currently overpaying for these costs. *Id*. at 14-17.

163. In rebuttal, NorthWestern witness Normand strongly disagrees with the cost allocation recommendations of Higgins and Dismukes, and contends that their proposals do not reflect the capacity planning process and cost causation. Reb. Test. Paul Normand at 3-4 (Apr. 5, 2019). Normand contends that considering social policy objectives in a cost of service study reduces the value of the study as an unbiased measure of class contribution to costs. *Id*. at 9. Using the cost study results, the Commission can consider the impact of alternative pricing policies while developing moderated cost allocations and rate designs. *Id*. at 10. Normand states that there is no logical basis to suggest that social policies should influence the selection of allocation factors in the initial cost of service study. *Id*.

164. Similarly, Normand testifies that meters and service lines are plant-related investments at a specific location that generally cannot be used or shared with other customers, and so it is appropriate to reflect the cost of these investments in a fixed monthly customer charge. *Id*. at 19. Normand does not agree with Higgins that an Average and Excess study will provide an appropriate allocation of production costs. *Id*. at 21. Normand states that NorthWestern's generation facilities reflect energy generators with large energy users the major beneficiaries. *Id*. Finally Normand reasserts that his allocation of distribution costs on the basis of non-coincident class peak demand reflects that local loads are the primary determinant of facility planning with high load requirements in winter and summer. *Id*. at 22-23. Normand disagrees with Dismukes' proposal to introduce one-hour coincident peak demand because the coincident peak is largely unrelated to local loads. *Id*. at 23-24.

165. A summary of all party cost allocations and rate designs are included in the table below.

XIX: Comparison of Recommended Allocations to Class at NorthWestern's Proposed Revenue Requirement

Customer Class	Current	NWE	Percent Change	MCC	Percent Change	FEA/LCG	Percent Change
Residential	$224,428,436	$246,871,280	10.00%	$42,967,853	8.26%	$257,466,403	14.72%
Secondary GS-1	228,242,821	237,414,322	4.02%	243,825,163	6.83%	231,922,280	1.61%
Primary GS-1	24,565,861	25,552,994	4.02%	24,565,861	0.00%	23,056,610	-6.14%
Substation GS-2	19,254,414	20,028,116	4.02%	19,254,414	0.00%	17,870,274	-7.19%
Transmission GS-2	7,281,817	7,281,817	0.00%	7,281,817	0.00%	5,846,792	-19.71%
Irrigation	8,923,944	9,816,339	10.00%	9,661,127	8.26%	11,190,782	25.40%
Lighting	14,782,726	15,376,742	4.02%	14,782,726	0.00%	15,175,775	2.66%
Total	$527,480,019	$562,341,610		$562,338,961		$562,528,916	

ii. ***Settlement***

166. Paragraph 2 of the RR Settlement discussed how the $6.5 million revenue increase was allocated to customer classes, and included various additional rate design issues. Specifically:

> ¶2. The overall revenue increase of $6.5 million for electric service shall be allocated to NorthWestern's customer classes as shown on Exhibit A to this

Amended Stipulation in the sections labeled Settlement Revenue Allocation and Settlement Class Revenue Allocation on pp. 1-2 of the exhibit. The functional revenue changes shall be as shown on Exhibit A to this Amended Stipulation in the section labeled Functional Revenue Changes on p. 3 of the exhibit. For the General Service 1 Secondary Demand Non-Choice rate class, the General Service 1 Primary Demand and Non-Demand and Choice and Non-Choice rate classes, the General Service 2 Substation Choice and Non-Choice rate classes, and General Service 2 Transmission Choice and Non-Choice rate classes the rates shall be as shown in Exhibit A to this Amended Stipulation in the section labeled Rate Summary Proposed Rates on pp. 4-7 of the exhibit. For all other rate classes, the rates shown in Exhibit A on the section labeled Rate Summary Proposed Rates are illustrative as the rate design for those rates is not being settled in this Amended Stipulation. NorthWestern is not precluded from adjusting the rate components between the "Base w/o Tax" and "Property Tax Charge" in Exhibit A on a revenue neutral basis for any subclass, as may be necessary to recover the target property tax revenue requirement.

167. The table below shows the stipulated revenue allocation from the RR Stipulation, Ex. A at 2 (May 12, 2019). The table includes NorthWestern's equalized rate of return allocations, and the allocation proposals of the stipulating parties at hearing, with exception of Walmart, scaled to the total stipulated increase. The allocation proposals included Class increases capped at 1.54% (1.25x the system increase), with residual distributed across GS-1 & 2 classes. Test. Dismukes at 56, 57, 68. The allocation proposals also included Residential and Lighting classes at cost, Irrigation capped at a half-cost increase, with the residual amount distributed to GS-1 and 2 classes. Test. Higgins at 44–49.

XX: Comparison of Stipulated Allocations, NorthWestern Equalized Rate of Return, and Intervenor Allocations to Class Scaled to Stipulated Revenue Requirement

Customer Class	Current	Stipulated Allocations	Percent Change	NWE Equalized ROR	Percent Change	MCC	Percent Change	FEA/LCG	Percent Change
Residential	$224,428,436	$228,199,195	1.68%	$244,422,490	8.91%	$227,885,404	1.54%	$244,422,490	8.91%
Secondary GS-1	228,242,821	232,693,556	1.95%	217,910,620	-4.53%	230,430,813	0.96%	219,532,346	-3.82%
Primary GS-1	24,565,861	24,025,412	-2.20%	21,661,588	-11.82%	24,801,355	0.96%	21,799,087	-11.26%
Substation GS-2	19,254,414	17,887,351	-7.10%	16,791,348	-12.79%	19,438,992	0.96%	16,912,396	-12.16%
Transmissi on GS-2	7,281,817	6,839,811	-6.07%	5,586,303	-23.28%	7,351,622	0.96%	5,591,891	-23.21%
Irrigation	8,923,944	9,370,141	5.00%	12,695,665	42.27%	9,061,403	1.54%	10,809,805	21.13%
Lighting	14,782,726	14,964,554	1.23%	14,912,007	0.87%	15,010,431	1.54%	14,912,007	0.87%
Total	**$527,480,019**	**$533,980,020**	**1.23%**	**$533,980,021**	**1.23%**	**$533,980,021**	**1.23%**	**$533,980,021**	**1.23%**

iii. ***Commission Finding***

168. The Commission approves the stipulated revenue allocation and customer charge rates. With the exception of the Barsantis' objection to street lighting rates, the non-stipulating parties did not object to the various RR Stipulation provisions. Signatories to the Stipulation include the utility and all parties that evaluated NorthWestern's cost studies and presented alternative allocation proposals. The Commission finds that the mix of interests represented among the stipulating parties is sufficiently diverse to produce class revenue allocations that are just and reasonable. Absent insight into the hierarchy of priorities for each of the stipulating parties, or the trade-offs made by the parties during settlement negotiations, the Commission has no reason to think an alternative allocation would improve upon the negotiated outcome in this case.

B. Rate Design

i. ***Party Positions***

169. NWE witness Normand proposes monthly customer charge increases for each class equaling 25% of the difference between current levels and full cost of service levels. *Id*. at 50. The only exception is the irrigation class, in which he capped the increase at 10% due to excessive customer impacts. *Id.* at 51. Within the general service classes, Normand proposes that customer charge increases for demand and non-demand customers should be approximately equal. *Id*. Normand asserts that his proposed increases to customer charges properly recover meter and service lateral costs, and reduce the current high level of cross subsidy that exists due to excessive energy rates. *Id*. at 52.

170. MCC witness Dismukes recommends that the Commission reject all of NorthWestern's proposed increases to monthly customer charges, because that high customer charges are not consistent with energy efficiency objectives and that they shift the within-class cost recovery burden to lower use customers. *Id*. at 59-62, 68, Ex. DED-10.

171. HRC/NRD witness Dr. Thomas Power recommends the Commission reject NorthWestern's proposed increase to the residential customer charge and retain the charge at its current level. Test. Thomas Power at 12, 14 (Feb. 13, 2019). Dr. Power states that the proposed increase of 37% to the residential customer charge is five times the size of increase in the average residential bill. *Id*. A disproportionate increase discourages energy efficient practice and disproportionately burden low volume and low income consumers. *Id*. at 13. Further, Power

states that the argument that fixed costs should be collected in fixed charges is a play on words without economic justification. Test. Power at 13. He testifies that the term “customer costs” is not well defined and may refer to only those costs avoided by the utility when a customer terminates service, but has also been used to refer to additional costs up to a%age of all electric delivery costs. *Id*. at 13-14. A fixed monthly charge can be set anywhere in this range, and its level is a policy choice for the Commission, not a problem that accountants or economists can solve. *Id*. Power recommends that the fixed charge be based on the incremental costs incurred or avoided when a customer seeks or leaves electric service. Since the current charge is sufficient to cover these costs, he recommends the Commission retain the charge at its current level. *Id*. at 14.

172. NWEC witness F. Diego Rivas disagrees with NorthWestern’s proposals to increase customer charges to the residential and GS-1 secondary and primary non-demand customer classes. Test. F. Diego Rivas at 26 (Feb. 12, 2019). Rivas asserts that reductions to volumetric rates reduce customer control and dilute incentives to energy efficiency. *Id*. at 26-27. The cost effectiveness of energy efficiency measures would also be reduced, which would potentially increase the utility’s cost to serve load. *Id*. at 27. Rivas contends that increasing customer charges is unfair to customers who have made substantial investments in energy efficiency, and customers who use less electricity, including low income households. *Id*. He provides examples of rulings from the Minnesota and Missouri public utility commissions in 2015 that express the values of preserving customer control over bill impact and avoiding disparate impact to low volume users. *Id*. at 27-28. Rivas asserts that while cost of service studies provide useful benchmarks for establishing class allocations, the studies are not useful to identify the type of rates that will be established to recover the revenue. *Id*. at 28-29. Rivas recommends retaining the current level of fixed charges for the residential and GS-1 non-demand customers. *Id*. at 29.

173. In rebuttal, NWE witness Schwartzenberger testifies that as recently as December 31, 2016, the residential customer charge was $5.30/mo. Therefore an increase from the current level to $5.60/mo. should not be a shock to residential customers. Reb. Test. Schwartzenberger at 5. He compares the proposed rate of $5.60/mo. to the $4.60/mo. customer charge in 2001, which escalated for inflation, would be $6.50/mo. today. *Id*. at 6. Similarly Normand rejects the proposals of other parties to reduce his proposed residential customer charge. He contends that these recommendations reflect result-oriented analysis designed to support increased

concentration on a volumetric rate that currently recovers 95% of residential class revenue. Normand asserts that overpricing volumetric charges does not achieve economic efficiency; it shifts cost recovery.

174. The HRC/NRDC recommends no change to the residential customer charge, while NWEC recommends no change to the residential and GS-1 non-demand charges.

175. The RR Stipulation indicated that the parties stipulated to NorthWestern's proposed monthly delivery service charges, with the exception of customer charges for the Residential class, certain GS-1 classes, and the irrigation and lighting classes.

ii. ***Commission Finding***

176. In this case, the Commission approves the stipulated rates. Regarding monthly customer charges for the residential and GS-1 Secondary Non-Demand classes, various theories of regulatory economics and ratemaking exist which support a range of customer charges that would recover anywhere from 0% to 100% of delivery service costs. In this case, the Commission's objective is to set a customer charge that is supported by substantial record evidence and aligns with Commission priorities. Relatively low customer charges provide increased customer control over their bills and greater incentives for energy efficiency. More of the costs allocated to the class are recovered from high-usage customers, who also tend to have relatively higher incomes. Relatively higher customer charges provide increase revenue stability for the utility, reduce customers' ability to affect their bills through consumption decisions, and recover relatively more of the allocated costs from low usage customers.

177. With these rate design concepts in mind, the Commission determines it is appropriate to require a 2% increase to pre-interim charges for the Residential and GS-1 Secondary Non-Demand classes, rounded to the nearest dime. This increase is reasonable and approximates the stipulated increases to the class revenue allocations. This increase results in a $4.20 monthly charge for residential customers and $6.00 monthly charge for GS-1 Secondary Non-Demand customers.

178. For the non-stipulated GS-1 Secondary and Irrigation rate classes, rate changes shall reflect the proportionate stipulated changes to class revenues, as shown on page 1 of Exhibit A, rounded to the nearest dime.

C. Net Metering Customer Class

i. *System benefits of net metering resource; compliance with Minimum Information Requirements*

179. House Bill 219, enacted by the 2017 Legislature, amended Montana's net metering laws and established Mont. Code Ann. §§ 69-8-610 and -611. *An Act Revising Net Metering Laws*, HB 219, 65th Legislature (2017), *codified at* Mont. Code Ann. §§ 69-8-610 and -611 (2017). House Bill 219 required NorthWestern to submit a study of the benefits and costs of net metering to the Commission before April 1, 2018, for the purpose of allowing the Commission to consider, as part of a general rate case, whether net metering customers should be served by NorthWestern under a separate classification of service. Mont. Code Ann. §§ 69-8-610 and -611 (2017).

180. House Bill 219 authorized the Commission to establish minimum information requirements to be addressed in NorthWestern's benefit-cost study of net metering systems. The Commission opened Docket No. D2017.6.49 to establish the minimum information requirements for the study. After soliciting stakeholder comment on the parameters of a benefit-cost study, the Commission issued Minimum Information Requirements on August 9, 2017. Notice of Commission Action, Dkt. D2017.6.49 (Aug. 9, 2017).

181. The benefit-cost study was completed for NorthWestern by Navigant Consulting, Inc., and submitted by NorthWestern to the Commission on March 30, 2018. NorthWestern entered the study in the record of this docket, as an exhibit in the testimony of NorthWestern witness Eugene L. Shlatz, an employee of Navigant Consulting, Inc. ("Navigant").

- *Avoided energy cost*

182. VS/MREA argues that NorthWestern used PowerSimm production cost modeling to calculate avoided energy costs, not the QF-1 tariff method mandated by the Minimum Information Requirements. Corrected Test. Brianna Kobor at 53-57 (Mar. 4, 2019); VS/MREA Resp. Br. at 5-8 (Jul. 31, 2019); DEQ Resp. Br. at 5-6 (Jul. 31, 2019); Hr'g Tr. 1519-1520. NorthWestern counters that the QF-1 method is incompatible with the requirement that NorthWestern must study a range of NEM adoption rates, as the QF-1 method cannot measure system impacts of adding various amounts of NEM generators. Reb. Test. John Bushnell at 13 (Apr. 5, 2019); NWE Repl. Br. at 30 (Aug. 28, 2019). MCC testified that NorthWestern's benefit-cost study is generally in compliance and that the difference between the Minimum Information Requirements and NorthWestern's methods is likely not significant. DR VS/MREA-

155(a) (Apr. 1, 2019). DEQ states that NorthWestern failed to comply with the Commission's Minimum Information Requirements in that it disregarded the requirement to use the QF-1 method and instead used the proprietary PowerSimm model. DEQ Resp. Br. at 6. Because NorthWestern did not make PowerSimm licenses available to intervenors, NorthWestern's calculation of avoided cost, the largest component of the benefit-cost analysis, was done without the opportunity for public oversight. DEQ argues that the divergent calculations of avoided cost by NorthWestern and VS/MREA, respectively, highlight the problem caused by NorthWestern's failure to observe a Commission requirement.

183. The Commission's directive on this topic, i.e., to use the Commission's approved method for estimating avoided energy costs in setting standard QF-1 rates, was explicit. Notice of Commission Action, Dkt. D2017.6.49 attachment 1. Further, there is no record of NorthWestern notifying the Commission during the benefit-cost study process about its decision to utilize an alternative method, i.e., PowerSimm modeling, not specified in the Commission's Minimum Information Requirements. While there may be some validity to NorthWestern's rationale for not using the QF-1 approach and utilizing PowerSimm modeling as an alternative method, the QF-1 method is not burdensome, and the Minimum Information Requirements represent minimum requirements that NorthWestern could have fulfilled and supplemented by providing and advocating for a preferred alternative methodology. The Commission concludes that NorthWestern did not comply with the Minimum Information Requirements in the benefit category of avoided energy cost.

- *Avoided capacity cost*

184. VS/MREA states that NorthWestern used the Southwest Power Pool ("SPP") method to calculate avoided capacity costs, not an Effective Load Carrying Capability ("ELCC") or similar assessment required by the Minimum Information Requirements. VS/MREA further states that the Commission declined to adopt NorthWestern's recommendation, made in Docket No. D2017.6.49, to use the SPP method for determining avoided capacity costs. Corrected Test. Kobor at 61-71; Hr'g Tr. 1471. NorthWestern does not directly address VS/MREA's assertion that it did not perform an ELCC assessment or equivalent, but defends its use of the SPP method. NorthWestern surmises that an ELCC analysis would yield a result close to the QF-1-based capacity value of 6.1% of a facility's nameplate capacity, which is based on the SPP method and

which Navigant used in the benefit-cost study. Reb. Test. Tim Stanton at 4-5 (Apr. 5, 2019); Reb. Test. John Bushnell at 16-17 (Apr. 5, 2019); Hr'g Tr. 1476-1478.

185. The Commission's requirement states that NorthWestern "must perform an Effective Load Carrying Capability or similar assessment of the capacity contribution of solar customer-generators." However, NorthWestern used the QF-1 SPP method, and did so despite the Commission's decision not to adopt NorthWestern's recommendation for that approach during the Commission's development of the Minimum Information Requirements. *Id*. at 16-17. Without detailed explanation, Navigant contends that an ELCC analysis would yield a capacity value for NorthWestern closer to the 6.1% value from the QF-1 SPP calculation than the 21.5% value based on a capacity factor calculation used by VS/MREA. Rebut. Test. Stanton at 4-5. The Commission concludes that NorthWestern did not comply with the Minimum Information Requirements in estimating the avoided capacity cost benefit.

186. VS/MREA's alternative capacity value for NEM solar of 21.5% is unreliable because it is based on a method originally developed using wind resources outside NorthWestern's service area and, therefore, is not clearly similar to the ELCC analysis the Commission sought. Consequently, the Commission is left with no avoided capacity value calculation that complies with the Minimum Information Requirements or is derived from a methodology supported by substantial record evidence.

- *Avoided transmission and distribution costs*

187. VS/MREA asserts that NorthWestern used neither detailed marginal cost information for transmission and distribution costs nor the regression method developed by National Economic Research Associates ("NERA"), as the Commission required. VS/MREA Resp. Br. at 11-12; Hr'g Tr. 1486-88; *see also* Hr'g Tr. 1487:20-1489:11.Additionally, NorthWestern's distribution analysis applied an arbitrary cap to solar growth, required a 10% capacity exceedance for NEM customers, and was limited to substation capacity additions, which accounts for only 20% of total growth-related distribution investment. VS/MREA Resp. Br. at 12-13; Corrected Test. Kobor at 77-78. With regard to the 10% capacity exceedance, VS/MREA argues that NorthWestern does not apply such a standard to itself when evaluating traditional wired solutions for meeting capacity needs. VS/MREA Resp. Br. at 13; Corrected Test. Kobor at 76-77; DR VS/MREA-099(c). VS/MREA further asserts that NorthWestern's study assumes maximum avoidable substation investment of only $7.4 million per year, which is only 37% of

the annual expected growth-related substation investment of $19.7 million identified in the MCOS study and 16% of the $46.4 million in annual growth-related investment forecasted for NorthWestern's distribution system.

188. NorthWestern states that its methodology is more accurate and rigorous than the NERA method and that it did not include avoided distribution feeder costs because NEM solar cannot meet firm capability requirements. Hr'g Tr. at 1486, 1504-1505. NorthWestern argues that it established a 10% capacity exceedance for NEM customers per substation to ensure sufficient NEM solar capacity is available in the event of higher than expected demand or less than expected solar output. Test. Eugene Shlatz at ELS-17 (Apr. 5, 2019). NorthWestern states that it relied on detailed distribution substation information for the distribution avoided costs. NWE Repl. Br. at 33; Exh. NWE-41 at 15, 17.

189. MCC contends that NorthWestern's avoided transmission cost calculation utilizes generic deferral value and not company-specific data, so should not be used by the Commission. Test. Dismukes at 20-21.

190. NorthWestern's argument that its chosen methodology is more accurate than the NERA method has some merit, but its decision to divert from the Minimum Information Requirements led to legitimate criticism from VS/MREA and MCC about NorthWestern's alternative approach. The Commission concludes that NorthWestern did not comply with the Commission's direction and that the reliability of the quantitative results of NorthWestern's approach are not definitively demonstrated by record evidence. The Commission further concludes that VS/MREA's argument that NorthWestern's application of a 10% capacity exceedance for NEM systems is not a standard applied by NorthWestern to traditional resource solutions that rely on forecasted load information is uncontested by NorthWestern.

- *Commission Decision: System benefits of net metering resource; compliance with Minimum Information Requirements*

191. Due to NorthWestern's noncompliance with some key components of the Minimum Information Requirements, critical aspects of NorthWestern's benefit-cost analysis are procedurally unreliable, incomplete, and/or insufficient to demonstrate the avoided cost benefits of the NEM resource, which HB 219 requires the Commission to rely on to make fully reasoned and equitable decisions regarding service classification and rates for NEM customers. For this reason, and in keeping with the adjudicatory procedure the Commission applied in this case, the

Commission concludes that NorthWestern has not satisfied its burden of proof with regard to demonstrating the net benefits of the net metering resource.

ii. ***Cost of serving net metering customers***

- *Use of net load data vs. delivered/exported load data*

192. NorthWestern contends that it appropriately used net load data for NEM customers in its Embedded Cost of Service Study ("ECOS"), given that NEM customers have only one meter and, therefore, net information is all that is available. Hr'g Tr. 1289. NorthWestern argues that because transmission and distribution costs are driven by demand—and should be allocated based on demand—it is irrelevant that net loads, instead of separate inflows and outflows of energy, are used in the ECOS study. NWE Repl. Br. at 35.

193. VS/MREA argues that customer class definitions and rate design are related to the cost of services provided to the customer, but that exported NEM generation is a service the customer provides, in a separate transaction, to the utility. Cross-Intervenor Test. Brianna Kobor at 19 (Apr. 8, 2019). Any decision to modify class definitions and/or rate designs should only occur after determining whether NEM customers impose an unreasonable cost-shift, which should be determined by calculating the NEM customers' share of costs—as well as the revenue received from NEM customers—based on the delivered load of those customers. VS/MREA argues that the question of whether the compensation that NEM customers receive for their net exports to the utility is undervalued or overvalued requires a separate analysis because that export comprises a service provided to, not from, the utility. Corrected Test. Kobor at 18-19.

194. The Commission agrees with VS/MREA that NorthWestern's use of net load data in its ECOS study and accompanying development of rates for a new NEM customer class is an inferior analytical approach because it fails to differentiate between the two distinct transactions occurring between NEM customers and the utility, i.e., the provision of delivered load to the NEM customer by NorthWestern and the provision of exported power to NorthWestern by the NEM customer. NorthWestern's fusion of the two transactions through a net load approach lends itself to derivative—and ardently contested—representations of load profiles, CP demand, and NCP demand for NEM customers. Those representations in turn inform NorthWestern's cost of service analysis and proposed three-part rate for NEM customers, including a demand charge, which is based on the net load profile and demand calculations.

195. The Commission concludes that an analysis that separately evaluates the cost of service for delivered load and the system benefits of exported power, as recommended by VS/MREA, would more appropriately delineate between distinct transactions and allow for more targeted and refined rate design options that rest solidly on a foundation of actual data for each of the two distinct transactions.

- *Source of NEM customer load data*

196. VS/MREA questions the source of the NEM customer load data used in the ECOS study, describing it as artificial and derived through a convoluted series of assumptions and adjustments, and contends that NorthWestern should have used load research sample data for NEM customers like it does for all other residential customers in the study. VS/MREA Resp. Br. at 25. VS/MREA argues that NorthWestern's approach not only produced an incorrect load shape for NEM customers, but was unnecessary because NorthWestern had actual load data and a valid sample from NEM customers that NorthWestern's own witnesses relied on for other purposes. Hr'g Tr. 1187-1188 (NorthWestern witness Dr. Ahmad Faruqui used load research data from a sample of 49 NEM customers in his derivation of load shapes and development of NorthWestern's proposed three-part NEM rate). VS/MREA states that NorthWestern's use of derived load data in its ECOS study overstated the cost of service for NEM customers compared to costs based on the sample of actual loads for those customers. VS/MREA Resp. Br. at 25-26.

197. NorthWestern contends that its ECOS study used the best available data source that met the needs of the analysis. NWE Repl. Br. at 36. Because the ECOS study focused on class allocation, it needed more data than a sample of NEM customers could provide—the ECOS study makes calculations involving CP and NCP demand for the entire class. Further, the data from the National Renewable Energy Laboratory that was used in NorthWestern's NEM benefit-cost analysis had the appropriate load shapes for the ECOS analysis. *Id*.

198. MCC disagrees with VS/MREA's criticism of the development of NEM load data in the ECOS study, arguing that NorthWestern's analysis was simply a scaling adjustment for residential load characteristics. Cross-Intervenor Test. David Dismukes at 54-55 (Apr. 5, 2019). MCC summarizes NorthWestern's ECOS approach for NEM customers by explaining that a customer's NCP will not change due to the installation of a rooftop system, despite lowering the customer's total electrical needs; however, NEM production is assumed to have a significant effect on utility CP demand. *Id*.

199. The Commission declines to pass judgment on whether NorthWestern's choice of load data in its ECOS study accurately represents the consumption quantities and patterns of NEM customers. However, NorthWestern's use, on one hand, of derivative data in its ECOS study and, on the other hand, actual data in its proposal for an NEM rate class and associated rates, raises the valid question of why NorthWestern did not use one data source—in this case, actual sample data from existing NEM customers—for both its ECOS analysis and rate class justification. NorthWestern's responses to VS/MREA's questions on this topic fail to answer the question satisfactorily, leaving the Commission with considerable doubt as to the degree to which the ECOS study can be used with confidence to justify NorthWestern's proposal for an NEM rate class. The Commission finds that NorthWestern should develop load research sample data for NEM customers of comparable quality to that used for the broader residential class for use in future cost of service studies.

- *Peak load methodology for distribution demand costs*

200. NorthWestern explains that, in its ECOS study, once costs were functionalized and classified, they were allocated to customer rate classes, and that those allocated costs to classes comprise the underlying foundation to the cost of service study results. Test. Normand at 12.

201. NorthWestern allocated distribution function costs classified as demand-related to customer classes based on an NCP method. NorthWestern developed an NCP demand figure for NEM customers through several steps. DR VS/MREA-112(a) (Dec. 21, 2018). Based on the premise that the average loads of NEM customers prior to converting to net metering are larger than the average non-NEM customer loads, NorthWestern computed the monthly NCP demand per customer for the larger net metering customers prior to converting to net metering. The net metering monthly% reduction in NCP demand (after installation of net metering) was then applied to the pre-net metering demands to arrive at the net metering NCP demands used in the cost of service study.

202. VS/MREA agrees that the NCP method is a standard means of allocating costs related to the distribution system because it recognizes that distribution system costs are driven by the peak loading on the distribution system equipment, which may occur at a different time than system peak. Corrected Test. Kobor at 31. However, VS/MREA disagrees with NorthWestern that an NCP should be measured separately for NEM customers, as opposed to in

relation to the residential class as a whole. *Id*. at 32-33. VS/MREA argues that, unlike the broad residential class whose demand dominates distribution substation loads serving that class, a NEM subclass is typically disbursed throughout residential areas, does not take service on designated feeders, and does not produce a load that dominates the substation it is connected to. *Id*. VS/MREA states that the separate NCP of NEM customers does not approximate the peak loads on the distribution system and is, therefore, irrelevant to cost causation and should not be used to allocate costs. VS/MREA Resp. Br. at 26; Hr'g Tr. 1190-1192.

203. MCC disagrees with NorthWestern's allocation of all distribution plant facilities on the basis of class NCP, arguing that design motivation for distribution components depends on local diversity, which can vary between primary voltage commercial customers and secondary electric circuits. Therefore, because some facilities should be allocated with CP loads and others with NCP loads, MCC recommends a 50/50 weighting of NCP and 1 CP by class, which results in a lower demand charge for NEM customers than NorthWestern proposes. Test. Dismukes at 44-46.

204. VS/MREA further objects in multiple ways to the method by which NorthWestern develops NCP demand for NEM customers. First, VS/MREA states that NorthWestern's method relies on inconsistent and unfounded assumptions, as it applies the production from a 5 kW solar array adopted by above-average energy users to a load shape of an average energy user. Corrected Test. Kobor at 28-29. NorthWestern thus ignores the relationship between energy use and system size by applying an oversized NEM system for the hypothetical load shape it is evaluating.

205. Second, VS/MREA contends that NorthWestern's use of demand at 8:00 p.m. on June 8 for the NCP of NEM customers is inappropriate because the NCP of NEM customers did not occur on that date and because the load of all residential customers at that time was half of its annual peak, which occurred at a different time and in a different season. VS/MREA Resp. Br. at 26-28; Corrected Test. Kobor at 34; Hr'g. Tr. 1246-1249.

206. Third, VS/MREA contends that the shortcomings in NorthWestern's method of calculating the distribution allocation factor for NEM customers were avoidable because actual load research data for a sample of NorthWestern's customers was available and could have been used in place of a method of approximation that introduced error. Corrected Test. Kobor at 29.

207. VS/MREA disagrees with MCC's proposed weighted allocation of distribution system costs, as it relies upon a NEM NCP based on net load and uses a NCP date that does not reflect NEM cost causation. Cross-Intervenor Test. Kobor at 24-26.

208. Given the RR Stipulation, the Commission finds that it is unnecessary to rule on the relative merits of the NCP allocation approach of NorthWestern and the 50/50 blend of NCP and 1 CP as proposed by MCC. However, because net load data, as opposed to delivered load data for NEM customers, underlies NorthWestern's analysis of distribution demand costs, the results of NorthWestern's approach as they pertain to NEM customers are not persuasive. For example, on a delivered load basis, the NEM NCP of 7,123 kW occurred on December 31. In contrast, on a net load basis, NorthWestern determined a NEM NCP of 6,535 kW on June 8. Such discrepancies can impact the allocation of costs of service and result in distorted rates for each of the distinct transactions between the utility and NEM customers. In addition, as already stated, the Commission finds that load research data specific to NEM customers should be the basis for measures of their demand, whatever allocation method is applied.

209. Although the Commission agrees with VS/MREA's delivered load approach to cost of service, it is not convinced that, in VS/MREA's allocation of distribution demand-related costs to the NEM customer group, the NEM customers' contribution to the total residential class demand is the relevant NCP measure. The Commission interprets HB 219 to require an evaluation of the cost of serving NEM customers as if they were a separate customer group in order to determine whether that cost of service differs enough to warrant establishing a separate rate classification.

- *Peak load methodology for transmission demand costs*

210. In its cost of service study, NorthWestern utilized the "12CP" method to allocate transmission costs to the various rate classes. DR PSC-001, NWE MT Electric Allocators Rev 8-30-18.xlsc (Oct. 12, 2018). For the NEM customer group, NorthWestern tabulated test-year monthly coincident peak demand based on net load. For three months—May, July, and August—the net load-based demand figures were negative, i.e., the NEM group was exporting during the coincident peak period. Instead of using the negative net load numbers for those three months in calculating the average 12CP, NorthWestern applied the value of zero. Hr'g Tr. 1195-97.

211. VS/MREA's overarching objection to the use of net load data in NorthWestern's ECOS analysis applies to the allocation of transmission demand costs. Corrected Test. Kobor at

16-19. While VS/MREA acknowledges that allocation of transmission costs should be based on a 12CP methodology, it argues that the utilization of net load data in that methodology is erroneous and that a proper cost of service approach to NEM systems involves separate analyses of both transactions between utility and NEM customer, i.e., the distribution of energy from the utility to the NEM customer and the export of energy from the NEM customer to the utility. *Id.* at 17.

212. With regard to NorthWestern's application of the 12CP method to NEM customers, VS/MREA contends that assigning a zero value to NEM customers for three months effectively removed the exports from the study, thereby denying any benefit to NEM customers for three months of net exports. Corrected Test. Kobor at 35-37. VS/MREA contends that on July 13, when NorthWestern's transmission system was most constrained, NEM customers were net exporters and thus serving the loads of neighboring customers and lowering the demand on NorthWestern's constrained transmission system. VS/MREA repeats its opposition to the use of net load for cost allocation in the cost of service study, but argues that if the net load approach is used, it must be used consistently. VS/MREA concludes that NorthWestern's method produces a 12CP allocator that is almost 20% higher than a 12CP calculation based on a consistent net load approach.

213. MCC states that NorthWestern's capping three months at zero was appropriate. Test. Dismukes at 58. It contends that VS/MREA's argument ignores the fact that NEM customers still rely upon NorthWestern's distribution and transmission system even when the NEM customer group operates as a net exporter, and that the utility will still incur investment costs regardless of which direction electricity flows.

214. While NorthWestern argues that its assignment of zero value to the coincident peak net load for NEM customers in the three months of the year when NEM customers had net exports was justified because NEM customers are still using the grid when exporting, the Commission agrees with VS/MREA that adjustments to zero for exporting months represent an inconsistency in NorthWestern's use of net loads in its cost-of-service analysis. While it is true that NEM customers utilize NorthWestern's distribution system in exporting energy, those same exports would have the effect of reducing demand on NorthWestern's transmission system. Here, the problems associated with NorthWestern's use of net-load data are compounded by an unwarranted subordination of data, creating not only a methodological inconsistency, but

exemplifying why a separate and comprehensive analysis of each of the two distinct transactions occurring between NorthWestern and its NEM customers is necessary to create an accurate picture of the transmission demand costs of net metering systems.

iii. ***Whether to Establish a Separate Classification for NEM Customers based on Load Shape***

215. NorthWestern asserts that there is empirical evidence that the net load shapes of NEM customers differ significantly from the load shape of the typical residential customer. Test. Ahmad Faruqui at 12 (Sep. 28, 2018). Those differences in load shapes, combined with a mostly volumetric residential rate design, results in a significant shift in the recovery of power system infrastructure costs from NEM customers to non-NEM customers and justifies the creation of a NEM customer class.

216. VS/MREA argues that NorthWestern's alleged differences in load shapes do not relate to cost recovery and that it is not load shape alone, but the cost-causing loads used in the cost of service study that should guide class definitions. Corrected Test. Kobor at 113-115. VS/MREA contends that NEM customers' loads fall within the range of variation in the residential class and that NorthWestern fails to provide any quantitative threshold at which differences in load shapes warrant separate class definition. *Id.*; VS/MREA Resp. Br. at 44-45.

217. NorthWestern states that VS/MREA's analysis inappropriately compares average NEM loads with outliers in the residential class, while what is more important than the range of values in a class is the median. NWE Repl. Br. at 40.

218. VS/MREA further argues that load shape is not a basis for rate-setting provided in HB 219; rather, the Legislature mandated that separate classifications and rate treatment can be based only upon net benefits and cost of service analysis. VS/MREA asserts that HB 219 reflects the Legislature's intent that the Commission would not subject a NEM class decision to the general ratemaking standard. VS/MREA Resp. Br. at 43; HB 219 §§ 2(1), 3(1); *Id.* § 4(1), (3). NorthWestern counters that Mont. Code Ann. § 69-8-611 (codified from HB 219) does not specify the grounds upon which the Commission must base a new class decision and that the statute does not include the word "only" regarding the factors for a class-establishing decision. NWE Repl. Br. at 39-40.

219. MCC offers as one of its reasons for supporting a new NEM rate class the argument that NEM customers have distinct load profiles and overall usage characteristics. VS/MREA-155(b) (Apr. 1, 2019).

220. NorthWestern shows that the load shape for a typical NEM customer differs from that of a typical non-NEM customer, but does not sufficiently demonstrate how significant that difference is and, importantly, to what degree it should influence a decision whether to require a new rate class. VS/MREA argues, with supporting data, that NEM customers' loads fall within the range of variation in the residential class. Further, NorthWestern has not demonstrated a strong empirical connection between a differing NEM load shape and differing cost of service, as its analysis is based on a net load approach, which, as indicated above, the Commission finds to be analytically deficient.

221. The Commission denies NorthWestern's proposal to establish a separate rate class for net metering residential customers. As described above, NorthWestern did not comply with various and significant directives of the Commission's Minimum Information Requirements, and its cost-of-service analysis for NEM customers, much of which is based on the improper use of net load data, yields results that fail to distinguish and accurately measure the costs associated with the two distinctive transactions that occur in NorthWestern's relationship with NEM customers.

iv. ***Whether to Adopt a Demand Charge for NEM customers***

222. NorthWestern argues that its proposed demand charge, intended to recoup fixed transmission and distribution costs, is consistent with established ratemaking principles; is a proven concept that has been offered to industrial and commercial customers, as well as residential customers in several states, for decades; is comprehensible to customers and may be expected to prompt customers to modify their electricity consumption patterns; and will promote the adoption of beneficial technologies like smart thermostats and batteries. Test. Faruqui at 5-6. NorthWestern's proposed demand charge of $7.69/kW-month would amount to approximately $45/month for the average NEM customer (while the volumetric rate for NEM customers, reflecting only supply costs and applying to both delivered and exported loads, would decrease to $0.062807/kW). *See* Test. Faruqui at 8, 63; Hr'g Tr. 1276 (This calculation is made on the basis of direct NorthWestern testimony and revisions in NorthWestern's demand charge and volumetric rate proposed for NEM customers that were provided by NorthWestern in hearing and attributed to the RR Stipulation).

223. As part of implementing its proposed new NEM tariff, NorthWestern states that it intends to develop both a customer education program and an internal training program. Test.

Bobbi Schroeppel at 19 (Sep. 28, 2018); Rebut. Test. Schroeppel at 14-15 (Apr. 5, 2019). NorthWestern contemplates the publication of fact sheets that address issues associated with net metering, including the demand charge.

224. VS/MREA argues that there is no empirical evidence that residential customers are able to respond to the type of demand charge proposed by NorthWestern; that the nature of residential customers and their loads do not allow demand charges to provide actionable price signals; and that a majority of utilities and regulatory commissions have rejected mandatory demand charges for residential customers. Corrected Test. Madeline Yozwiak at 19-28 (Mar. 4, 2019); VS/MREA Resp. Br. at 33–37; Hr'g Tr. 1927-1934. VS/MREA contends that NorthWestern's cited research on the response of residential customers to three-part rates is dated; that the majority of three-part rates offered to residential customers are voluntary; and the few entities that impose a mandatory demand charge consist primarily of rural cooperatives and municipal utilities. Corrected Test. Yozwiak at 23, 28.

225. VS/MREA argues that there are no costs caused by an individual customer's peak use, which is what the proposed demand charge targets. VS/MREA Resp. Br. at 38.

226. MCC supports the proposed demand charge because, in addition to NorthWestern's analysis, other groups have found evidence that net metering leads to intra-class subsidies, and because NEM customers can be expected to have a relatively sophisticated understanding of the concept of electrical demand. Cross-Intervenor Test. Dismukes at 25-26 (*See* footnote 46, citing E3 and Edison Foundation Institute for Electric Innovation).

227. MCC finds fault, however, with NorthWestern's proposed demand charge because NorthWestern's cost recovery is based on an evaluation of the entire residential class and not on the grandfathered NEM customers used as the basis to determine all estimated billing parameters. Cross Test. Dismukes at 80-81. MCC states that NorthWestern's proposed NEM revenue calculations result in an annual requirement of $1,690,723 at existing grandfathered levels, yet NorthWestern's own revenue allocation and rate design workpapers reflect a figure of $1,186,271. *Id*. at 81. MCC recommends a demand charge of $4.71/kW-mo., in contrast to NorthWestern's original proposal of $8.64/kW-mo. *Id*. at 79-80 (The values cited here reflect calculations based on the revenue requirement as originally provided by NorthWestern. The revenue requirement subsequently changed, resulting in amended demand charge

recommendations from both MCC and NorthWestern, i.e., \$4.49/kW by MCC and \$7.69/kW by NorthWestern. *See* MCC Resp. Br. at 24 (Jul. 31, 2019), and NWE Repl. Br. at 4-5.

228. DEQ contends that the examples provided by NorthWestern of demand charges implemented by other utilities are not relevant to NorthWestern's proposal, either in terms of how the demand charges of other utilities are structured or the magnitude of demand charges assessed. DEQ further asserts that NorthWestern does not possess either the utility meter data for NEM customers or a detailed plan to provide adequate customer education to prospective NEM customers. DEQ Resp. Br. at 7-10.

229. Based primarily on the above discussions about NorthWestern's use of net load data in its embedded cost-of-service analysis and its non-compliance with the Commission's Minimum Information Requirements in deriving avoided costs, the Commission concludes that NorthWestern did not demonstrate the reasonableness of its proposed demand charge for NEM customers and, therefore, rejects it. In addition, the fact that residential customers on NorthWestern's system do not have any actual experience with demand-based billing, coupled with evidence that NorthWestern did not present a fully-formed plan for educating potential new NEM customers regarding demand billing, raise additional concerns with NorthWestern's proposal.

v. ***Alternatives to a Demand Charge for NEM Customers***

230. NorthWestern describes an alternative to its proposed three-part NEM rate, a two-part rate comprising a variable energy charge of \$0.066/kW (equal to the energy charge of the three-part rate) and basic service charge of \$55.80/month. NorthWestern states that such a rate has the disadvantage of not providing customers with a price signal to manage peak demand. Test. Faruqui at 42; *Id*. at 58. VS/MREA counters that NorthWestern's two-part rate alternative is not designed based on established principles and describes the proposal as a foil against which the unpopular demand charge seems better. Corrected Test. Kobor at 139.

231. VS/MREA offers that time-varying (or time-of-use, i.e., "TOU") rates can provide a useful tool to improve the link between cost causation and customer rates, while avoiding many of the issues with customer acceptability presented by residential demand charges. *Id*. at 140. NorthWestern responds that TOU rates have several disadvantages relative to three-part rates, arguing that a purely volumetric TOU charge would recover customer- and

capacity-related costs, but reductions in load are still likely to create insufficient recovery of fixed costs. Reb. Test. Faruqui at 21.

232. VS/MREA recommends that, if the Commission decides to modify the current net metering tariffs, it should address the compensation paid for solar customers' exported electricity, a ratemaking option authorized by the Legislature in HB 219. VS/MREA Resp. Br. at 31-32, *citing* HB 219 § 2(3) and Mont. Code Ann. §§ 69-8-603, 69-8-611(3). VS/MREA states that the Legislature authorized the Commission to separate inflows from outflows and set "separate rates for customer-generators production and consumption … if it finds it is in the public interest and as part of a public utility's general rate case" (quotation in original).

233. VS/MREA contends that, in testimony during the hearing, NorthWestern agreed with VS/MREA that, if a rate is adopted pursuant to Mont. Code Ann. § 69-3-611(3), the exception described by statute is met and a full retail rate for net metered energy is not required. *Id*. at 31, citing Hr'g Tr. 1564. However, NorthWestern argues that no party in this case presented the option of an adjusted export rate to the Commission, and it is unclear if simply revising the production rate received by NEM customers would alleviate the cross-subsidy issue. NWE Repl. Br. at 46.

234. Ratemaking alternatives to NorthWestern's proposal for the establishment of a residential NEM class and associated three-part rate, such as TOU rates, an increased basic service charge, or an adjusted NEM export rate, although referenced in the record by various parties, were not offered in the context of fully developed tariff structure or specific rates, nor were they subjected to thorough examination by docket parties. The Commission concludes that the evidentiary record lacks sufficient foundation upon which the Commission could consider alternatives to the fundamental components of NorthWestern's proposal.

vi. ***Grandfathering***

235. NorthWestern states that the grandfather clause of HB 219 provides that a new NEM class applies to customers interconnecting on or after the date on which the Commission adopts a final order establishing the class. Reb. Test. Schwartzenberger at 12-17; NWE Repl. Br. at 50-52. However, NorthWestern recognizes that the term "interconnecting" in the statute requires interpretation, and it therefore recommends that a NEM customer's date of interconnection be considered as the date on which the local or municipal electric code official with jurisdiction documents approval. NWE Repl. Br. at 51.

236. Arguing that grandfathering policy should be based on dates within control of the NEM customer, not NorthWestern, VS/MREA proposes that NEM customers who submit an interconnection request within 60 days of the Commission's rate case order should be grandfathered under the current NEM rates and structure. Test. Andrew Valainis at 10-14 (Feb. 13, 2019); Corrected Test. Kobor at 143-151; HB 219, § 3(1); Hr'g Tr. 1858-1861; Hr'g Tr. 1899-1900. Such a period would allow time for customers to be notified of policy changes and provide them with a fair opportunity to move forward with a NEM installation before the changes are implemented. VS/MREA argues that its proposed 60-day period does not conflict with HB 219, as the statute leaves discretion to the Commission to decide a specific date "on or after" a final order is issued. VS/MREA Resp. Br. at 46-47. NorthWestern counters that VS/MREA's proposal for a 60-day interconnection request period is not allowed by HB 219. NWE Repl. Br. at 50-52.

237. Because the Commission rejects the establishment of a new NEM class and associated class-specific rates and charges, the existing rate structure for NEM customers will not be altered in this Order. Therefore, the issue of grandfathering existing NEM customers is moot, and no Commission decision on the subject is necessary.

D. WAPA/FEA Proposal

i. ***Party Positions***

238. FEA represents Malmstrom Air Force Base ("Malmstrom") located near Great Falls, Montana. FEA proposed a new tariff, or similar option, to allow Malmstrom to benefit from less expensive electricity provided by federally owned hydroelectric resources within the Western Area Power Administration ("WAPA") service territory.

239. WAPA is a federal Power Marketing Administrator within the U.S. Department of Energy that markets and transmits wholesale electricity at cost to market participants, and is not a retail supplier of either bundled or unbundled retail supply. Test. Brian Collins at 2 (Feb. 12, 2019); Test. Michael Radecki at 3–4 (Feb. 12, 2019). WAPA is authorized to provide power to governmental entities like Malmstrom under the Pick-Sloan Missouri Basin Program ("Pick-Sloan"). This program allows WAPA to enter into interagency agreements similar to, though different from, power purchase agreements. Test. Radecki at 2. Under Pick-Sloan, the Air Force (Department of Defense) and WAPA (Department of Energy) have entered into a 1963

interagency agreement which provides the Air Force with a specific allotment of WAPA power, which is currently under-utilized. *Id.*; Hr'g Tr. at 1128, 1132.

240. WAPA is currently revising its power allocations, which will likely result in an interagency agreement between WAPA and the Air Force for WAPA power allocations lasting until 2050. Test. Radecki at 4, 9; Collins Dir. Test at 3; Hr'g Tr. at 1113. FEA represents Malmstrom could receive up to 5 MW of power per month, amounting to approximately 21,000 MWh of power annually, from WAPA's pool of resources. Test. Collins at 4; Hr'g Tr. at 1139.

241. To receive the benefits of this power, FEA initially proposed a new NorthWestern tariff credit. This mechanism would provide Malmstrom a reduction for WAPA power either received by Malmstrom, or by NorthWestern at the point of interconnection between NorthWestern and WAPA transmission systems. Test. Collins at 7, Ex. BCC-1; Test. Hines at 4. The credit would be calculated by the rates for hydropower facilities in NorthWestern's QF-1 tariff, adjusted for line losses. Test. Collins*,* at 5, 7. This credit would reduce Malmstrom's electricity bill under its services received under NorthWestern's GSEDS-2 (Delivery Service) and ESS-1 (Supply Service). *Id.* at 7. Because this 5 MW capacity is less than Malmstrom's current energy needs, it would continue to utilize NorthWestern for additional energy. Hr'g Tr. at 1108; Test. Hines at 7. While Malmstrom would pay WAPA a commensurate amount for the NorthWestern bill credit, the wholesale-at-cost WAPA power could reduce Malmstrom's total electricity costs compared to continuing to receive its power entirely from NorthWestern. Test. Collins at 13. FEA unsuccessfully attempted to resolve this issue with NorthWestern prior to the general rate case. *Id*. at 10.

242. During the hearing and in post-hearing briefing, FEA amended its initial proposal. Instead of a crediting mechanism based on the QF-1 tariff, or a similar analog, FEA proposes the Commission direct FEA and NorthWestern to negotiate the terms of an agreement in good faith and jointly submit, within 6 months of the date of the Commission's order, a negotiated financial crediting agreement establishing rates for review by the Commission. FEA Repl. Br. at 2 (Jul. 31, 2019).

243. Regardless the mechanism, FEA provides several policy arguments to support its receipt of WAPA power. The resource would benefit customers by providing needed capacity to NorthWestern's capacity deficient system which indicates a negative 28% planning reserve margin. Test. Collins at 9. This is doubly-important, FEA argues, because NorthWestern has 220

MW of long-term PPA capacity (non-QF) expiring between 2020 and 2026. *Id.* at 9–10, Ex. BCC-2. Importantly, this resource would only be available for Malmstrom, as federal law precludes its assignment to third-parties; NorthWestern would not be able to purchase and resell the power to its customers. *Id.* at 11. This tariff also would not be precedent setting, as WAPA power is only available to Malmstrom. FEA Resp. Br. at 6. Even if precedential, the specific facts are narrow which would preclude replication because WAPA infrequently re-allocates rights to its resource pool (low potential for additional WAPA power recipients), and because there are no additional air force bases which could receive WAPA power. *Id.* at 7. Finally, even though the mechanism is not fully developed, the parties can negotiate a crediting arrangement to resolve any potential adverse impacts. *Id.* at 8.

244. FEA also proposes several legal arguments to support its ability to receive power from WAPA. The proposal is legal under state law, as Malmstrom will not become a choice or dual-supply customer, because it will continue to remain a retail customer of NorthWestern, but will only receive a credit for WAPA power received either directly by Malmstrom, or by NorthWestern at the point of interconnection with WAPA. *Id.* at 3; *see also Id.* at 11-13. Similarly, wholesale deliveries of federal hydropower were not contemplated by Montana's Reintegration Act, and should not be precluded. *Id.* at 10. Even if the proposal is illegal under state law, state law could be preempted by the U.S. Constitution. *Id.* at 14, *citing U.S. v. California,* 921 F.3d 865 (9th Cir. 2019). Similarly, the proposal is legal under federal law. *Id.* at 8-10.

245. The LCG supports the FEA's efforts to supply Malmstrom with WAPA Power. LCG Resp. Br. at 22 (Aug. 13, 2019). LCG argues that "a solution can be forged which benefits the FEA, NorthWestern, and all of NorthWestern's customers." *Id.* at 23. While financial and operational details "remain to be negotiated," the Commission "should find it has the authority to approve the arrangement proposed by the FEA and encourage the FEA and NorthWestern to find a solution that will allow Malmstrom to utilize its allocation of WAPA Power." *Id.* at 25.

246. LCG disagrees that a WAPA power arrangement is illegal. LCG notes that Montana's Electric Utility Industry Generation Reintegration Act does not preclude any customers from their own cogeneration or self-generation. *Id.* at 23, *citing* Mont. Code Ann. § 69-8-201(3). LCG argues, "Given Malmstrom's unique position as a *Federal customer* of NorthWestern's with rights to an allocation of *Federal hydropower* from WAPA, it is reasonable

for the Commission to find that Malmstrom is effectively self-generating a portion of its power supply." *Id.* at 23. It is immaterial, LCG notes, that the power would need to be transmitted across NorthWestern's system, because energy consumption can be met by "remote self-supply, in which power is obtained from an affiliated, off-site facility." *Id.* at 23, *citing Calpine Corat v. F.E.R.C.,* 702 F.3d 41, 42 (D.C. Cir. 2012). Similarly, the Commission has broad service classification and supervisory and regulatory powers over NorthWestern which would support the relief Malmstrom requests. *Id.* at 24, *citing* Mont. Code Ann. §§ 69-3-306, -330(3).

247. Not only does LCG argue that the transaction is legal, LCG argues that the transaction would provide benefits to Montana: it would mitigate against NorthWestern's capacity deficit; it would add low-cost resources to NorthWestern's power supply portfolio; and "is simply good policy for all Americans." *Id.* at 24.

248. In contrast, NorthWestern responds that the FEA's proposal is illegal. NorthWestern In. Br. at 39; Test. Hines at 6–7. Specifically, in 2007 the Montana Legislature passed House Bill 25 which deleted the specific language in Mont. Code Ann. § 69-8-201 that permitted public agencies to choose alternative default electric suppliers. *Id. citing* Ex. NWE-57. The revised Mont. Code Ann. § 69-8-201(1) prevents dual-supply power supply like FEA is proposing. Because NorthWestern argues the Commission is statutorily precluded from allowing FEA to procure electricity from WAPA, "Malmstrom's remedy is with the Legislature, not the Commission." *Id.* at 40.

249. NorthWestern is similarly concerned with the hypothetical nature of the transaction, regarding its under-developed contract terms, energy valuation, establishing precedent, and impact to customers. Test. Hines at 7. NorthWestern also argues that FEA is effectively requesting a declaratory ruling. NorthWestern Repl. Br. at 56. Yet because FEA did not follow the Commission's rules for declaratory rulings, the record lacks sufficient facts to issue a declaratory ruling, and because several of FEA's arguments were only presented in post-hearing briefing, the request must be denied. *Id.* at 56.

250. Similarly, MCC argues that "Rather than attempting to adjudicate the legality and terms of a new special tariff for Malmstrom based on the limited record in this case, the Commission should recognize that further negotiations and a stand-alone proceeding will likely be necessary." MCC Resp. Br. at 28.

ii. ***Commission Finding***

251. The Commission finds that it lacks sufficient evidence in this docket to address FEA's proposal. However, as discussed below the Commission directs the parties to attempt to resolve the issue and bring a solution to the Commission, and if not, the Commission will resolve the issue through a contested case proceeding.

252. The Commission is aware of the legal ambiguities presented by FEA's proposal. It could be illegal because it would allow Malmstrom (a current existing NorthWestern residential customer) to choose an alternative supplier (WAPA), which is precluded by Mont. Code Ann. § 69-8-201(1)(c). Even if legal (i.e., because the arrangement can be construed as "self-generation" under Mont. Code Ann. § 69-8-201(3)), it is unclear what "self-generation" requires for this crediting mechanism. It could establish undesirable precedent, because establishing a crediting mechanism for "self-generated" power—even though the power is generated off-site and needs to be transmitted to NorthWestern's system—could reasonably be extended to a variety of other entities like multi-campus university systems, large businesses with dozens of intra- and inter-state locations, and other state and federal agencies. The exception could reasonably consume the prohibition against dual-supply.

253. However it could also be legal under state law. Mont. Code Ann. § 69-8-201 does not apply to retail customer self-generation, and Malmstrom's proposal (a federal agency) is to receive power from WAPA (a federal agency), which could reasonably be construed as self-generation. Mont. Code Ann. § 69-8-201(3). Hr'g Tr. at 1091. Additionally, it could be legal under federal law. Even if illegal under state law (neither permitted "self-generation" under Mont. Code Ann. § 69-8-201(3) and prohibited dual supply under Mont. Code Ann. § 69-2-201(1)(c)), Montana's statutes could be preempted by the U.S. Constitution. Either the Commission lacks the power to determine who Malmstrom receives power from (Enclave Clause, U.S. Const. Art. I, § 8, cl. 17), or because the Pick-Sloan program which authorized Malmstrom to receive power from WAPA preempts any conflicting state action (Supremacy Clause, U.S. Const. Art. VI, cl. 2). *See generally Arizona v. United States,* 567 U.S. 387, 398–400 (2012) (discussing federal preemption under the Supremacy Clause).

254. The Commission finds that, while reasonable and an efficient off-the-shelf resolution to Malmstrom's request, NorthWestern's QF-1 tariff does not provide the best proxy for valuing received WAPA power. Hr'g Tr. at 1096. Rather, a more tailored solution is

necessary, yet there is insufficient evidence to establish a new NorthWestern tariff with FEA's proposed crediting mechanism.

255. For example, the record lacks sufficient understanding of various important issues. The controlling interagency agreement terms and conditions between the Air Force and WAPA. Test. Collins at 3. This includes an understanding of the amount of power Malmstrom requires, the appropriate transmission routes and costs to transmit WAPA power to a NorthWestern interconnection point, whether Malmstrom would actually receive WAPA power, and any related agreement terms including contract length and opportunity for price adjustments if necessary. Additionally, the record lacks discussion of relevant NorthWestern transmission and distribution costs for WAPA power, if any, from the point of NorthWestern interconnection to delivery to Malmstrom. Test. Radecki at 6. FEA asserts that WAPA power is a firm energy resource. *Id.* at 8. This could allow WAPA power recipients to designate the power as a network resource, qualifying for Network Integration Transmission service rates under most utility Open Access Transmission Tariffs. *Id.* FEA asserts that WAPA power can be utilized to meet resource adequacy requirements within the Midcontinent Independent System Operator, or as an energy or capacity resource within the Southwest Power Pool. Hr'g Tr. at 1131. This could allow WAPA and NorthWestern to schedule, manage, and coordinate issues regarding the resource. *Id.*; Test. Radecki at 8. However the record evidence is lacking to justify these representations. Additionally, after receipt of the power onto NorthWestern's system, it is unclear what additional transmission or distribution costs could be incurred.

256. Accordingly, the Commission declines to establish a new tariff mechanism in this proceeding. Rather consistent with FEA's amended advocacy, the Commission directs NorthWestern to engage in good-faith negotiations with FEA regarding the mechanism, and within three months from the effective date of the rates established by this Order, present the mechanism to the Commission for approval.

257. Given the importance of this issue—that WAPA could provide much needed capacity to NorthWestern's capacity-deficient system—if the parties cannot reach an agreement within this timeline, the Commission will initiate a contested case proceeding under Mont. Code Ann. § 69-3-324, and resolve FEA's proposal under Mont. Code Ann. § 69-3-330. This direction, or a similar analogue, was supported by MCC and FEA/LCG, and is consistent with

NorthWestern's advocacy that "a stand-alone proceeding will likely be necessary to address FEA's request." NorthWestern Repl. Br. at 54.

E. E+ Green Tariff Settlement

258. The E+ Green tariff is an optional tariff required by Montana statute. Mont. Code Ann. § 69-8-210 (2). NorthWestern's initial Green Power Product Offering Program Rate Schedule was approved by the Commission on October 8, 2002. Dkt. D2002.7.81, Interim Order No. 6448. The current E+ Green tariffs were re-approved in Docket No. D2009.9.129 in Order No. 7046h with minimal changes to the original tariffs.

259. DEQ suggests that a replacement or supplementation of NorthWestern's E+ Green tariff should be developed in consultation with NorthWestern and other stakeholders, and NorthWestern should file a proposal to replace or supplement the current E+ Green tariff within 120 days of the conclusion of the final order in this docket. Test. Daniel Lloyd at 13 (Feb. 12, 2019). The tariff allows retail customers to purchase 100-kWh blocks of "green tags" at a rate of $0.02/kWh (or $20/MWh) per month. The green tags consist of Renewable Energy Credits ("RECs") purchased by NorthWestern from the Bonneville Environmental Foundation on behalf of the E+ Green customers. Enrollment between 2013 and 2017 averaged 289 residential customers and 16 commercial customers. The price of RECs has declined over the period of the program, to $8/MWh as of January 30, 2019. *Id.* at 7. The over-collected revenues from the program are transferred to NorthWestern's Universal System Benefits Renewable Resources Program.

260. Walmart is involved in contracting for off-site and on-site renewable resources in other states, and engages in utility partnerships to develop commercial and industrial programs that have minimal impact on non-participating customers. Test. Chriss at 19-20. Walmart suggests that the Commission should require NorthWestern and interested parties to develop and submit a filing for a new renewable product offered to commercial and industrial customers within 120 days of a final order in this case. *Id.* at 22.

261. The MCC recommends that NorthWestern be directed to address concerns regarding the pricing of RECs in the E+ Green program, and suggests that a stakeholder group might be a worthwhile endeavor if it proceeds from a clean slate, without any pre-conceived direction to incorporate specific principles. Cross-Intervenor Test. Dismukes at 88. MCC notes that it is unlikely a workshop process would be completed in 120 days. *Id.*

262. NorthWestern states that a 120-day timeline to review the E+ Green program and study new renewable programs is too restrictive. Reb. Test. Schroeppel at 4. NorthWestern states that it is willing to review the programs, and would be willing to report back to the Commission with a recommended process and suggested deliverables, including a time-line that would be more appropriate than 120 days. *Id.* at 6-8.

263. On May 13, 2019, a Stipulation and Settlement Agreement between NorthWestern, DEQ, MCC, and Walmart was filed with the Commission related to NorthWestern's E+ Green tariff and other potential renewable energy products. The Stipulation requires NorthWestern to initiate a process to review its E+ Green program, which includes customer research and engagement with relevant stakeholders. The Stipulation also requires NorthWestern to make a filing to modify the existing E+ Green tariff, propose a new renewable energy product tariff, or justify maintaining the existing tariff without changes.

264. The Commission finds that the E+ Green Stipulation has no impact on current rates. The low customer subscribership illustrates that the tariffs, which have been in place for 17 years with minimal modifications, are not currently successful in attracting a customer response. Additionally, the price of RECs has declined over the period of the program, indicating the current E+ green rate could possibly be reduced. There is no opposition from the other intervenors in this docket to the Stipulation.

F. Street Lighting Tariff

i. ***Party Positions***

265. In its Application, NorthWestern states that, for lighting, a simplified approach was used to set prices for the many lighting rates. Test. Normand at 54. NorthWestern explained that some lighting charges, e.g., operations, maintenance, and billing, were increased by a uniform 4.02%, while the ownership charges were based on the ECOS results with the same uniform increase for each rate. *Id*. The ownership charge was initially derived from the results of a marginal cost-of-service methodology in the general rate case of the Montana Power Company in 1996. Dkt. D2010.2.14, Ex (JS-2) at CAO-4 (Feb. 5, 2018).

266. In the Additional Issues identified in this case, the Commission included street lighting. Notice of Additional Issues, Dkt. D2018.2.12 (Mar. 1, 2019). The Commission requested that NorthWestern provide testimony that explains the differing treatment of the various lighting rates in the current rate proposal, as well as an explanation of NorthWestern's

method of allocating revenue requirement to each of the lighting charges (ownership, operation, maintenance, and billing). *Id*. ¶ 16. Further, the Commission sought explanatory and detailed information on how the ownership charges as proposed are derived from the ECOS results. *Id*.

267. In testimony on the additional issue of lighting, NorthWestern explains how each of the rate components of the lighting rate class were designed to achieve the proposed moderated base rate revenues. Add'l Issues Test. Normand at 2-3 (Mar. 22, 2019). NorthWestern states that in the ECOS study, the lighting class in total was producing a rate of return of 6.80%, compared to the total company rate of return of 6.43%. Similar to how rates were established for the other rate classes producing a higher rate of return than the total company rate of return, the increase in the base rate of the lighting class was set at 4.02% for the total of all of the lighting subclasses. The lighting subclasses include: Light Non Choice Company Owned; Light Non Choice Customer Owned; Light Choice Company Owned; Light Choice Customer Owned; Light Metered Non Choice Customer Owned; Light Metered Choice Customer Owned.

268. NorthWestern describes how the generation and generation property tax costs were determined for the lighting subclasses and explains that the base rates (excluding property taxes) for each of the lighting rate components—billing, maintenance, operations, billed meter, and ownership—were established uniformly for all subclasses by applying the base rate increase of 4.02% to present rates. *Id*. at 2.

269. NorthWestern states that the distribution base rate was calculated by subtracting all of the previously calculated proposed component revenues from the total proposed revenue target for the lighting class. *Id*. at 3.

270. NorthWestern explains that the generation costs for non-choice customers, the base rate, and property tax rates were set the same for all of the subclasses at a level to recover the total lighting base generation costs and generation property tax costs produced in the ECOS. The same procedure was performed in setting rates for all non-choice subclasses to recover the total lighting ECOS costs for Two Dot base and their property tax costs, and transmission base and property tax costs. A uniform property tax rate was calculated for distribution choice and non-choice based on the derived property tax levels from the ECOS results. *Id*.

271. Property tax rates for the separate rate components of billing, maintenance, operations, billed meter, and ownership charge were determined by spreading the ECOS costs based on present revenue levels. *Id*.

272. Base rates (excluding property taxes) for each rate component of billing, maintenance, operations, billed meter, and ownership were established uniformly for all subclasses by applying the base rate increase of 4.02% to present rates. *Id*.

273. The distribution base rate was then calculated by subtracting all of the previously calculated proposed component revenues noted above from the total proposed revenue target for the lighting class. *Id*.

274. The Barsantis raised several issues in their prehearing memorandum:

a. Is the ownership charge in NorthWestern's ELDS-1 tariff unreasonable or unjustly discriminatory?

b. Should NorthWestern normalize the revenue requirements for street lighting customer classes to include known changes by 2020 resulting from the transition to LED street lighting?

c. Should NorthWestern be required to reduce its rate base for any high pressure sodium street lights removed from service after transitioning infrastructure to LED technology?

d. Is NorthWestern recovering more than its original cost of its street lighting infrastructure, contrary to Mont. Code Ann. § 69-3-109, and if so subject to penalty under Montana's False Claims Act?

e. Was the Commission's prior approval of ELDS-1 an illegal act?

275. The Amended Stipulation approved by the Commission authorizes an overall revenue increase of $6.5 million for electric service, a decrease from the $34.9 million increase requested by NorthWestern in its application. Test. Robert Rowe at 5; Amended Stipulation at 1. As a result of the stipulation, the revenue requirement adjustment in the lighting class for charges related to transmission and distribution is an increase of $328,863 (+2.65%) from the existing revenue of $12,387,441, and the adjustment for charges related to generation is a decrease of $147,036 (-6.14%) from the existing revenue of $2,395,286. Amended Stipulation attachment A at 3. The specified adjustments in the Amended Stipulation include both base rates and property tax.

ii. ***Commission Finding***

276. Evidence in this docket does not merit revisiting the issues raised by the Barsantis regarding whether the ownership charge is unreasonable or unjustly discriminatory, and whether NorthWestern is recovering more than its original cost of its street lighting infrastructure, as the Commission considered and decided those issues in a previous docket. *In re Gruba Complaint,*

Dkt. D2010.2.14, Order 7084aa ¶¶ 33–60 (Feb. 15, 2019). In addition, and as previously stated, the Commission finds that the Amended Stipulation is a reasonable resolution of issues presented in this case related to NorthWestern's revenue requirement, and reasonably assigns responsibility for the revenue requirement to the various customer classes, including the lighting classes.

277. The Commission declines to address the Barsantis' concerns regarding LED street lighting because NorthWestern's LED replacement pilot project began in 2019, while the current rate case being discussed uses a historic test period of 2018. Further, no party provided substantial evidence supporting a rate base adjustment for a known and measurable change pursuant to Mont. Admin. R. 38.5.106 for the LED replacement project. The Commission concludes that any discussion on LED lighting is outside the scope of this docket.

278. With regard to the adjustment of charges within the lighting class, the Commission directs NorthWestern to file a lighting tariff that:

a. is based on the lighting class revenue requirement for base rate revenues resulting from NorthWestern's ECOS study, adjusted to reflect the Commission-approved Amended Stipulation and the revenue requirement therein;

b. reflects the revenue adjustments of a total increase of $328,863 from current revenue and a total decrease of $147,036 from current revenue in the lighting class for charges related to transmission and distribution, and generation, respectively;

c. reflects a uniform adjustment of all current lighting class base rate charges related to the transmission, distribution, and generation functions, by applying the magnitude of change between the current class revenue requirement and the stipulation-derived class revenue requirement for each of those two functions (i.e., an increase of 2.56% for charges related to transmission and distribution and a decrease of 6.14% for charges related to generation);

d. reflects uniform adjustments, based on the functional percentage adjustments specified above, to both the base rate and property tax components at each level of the range of ownership charges;

e. for each base charge in the lighting tariff calculated to a hundredth part of a dollar, including the operations, maintenance, billing, and ownership charges, any adjustment in the charge that does not increase or decrease by one cent through standard rounding practice shall be adjusted by one cent in order that these tariff rate elements will contribute to recovering the functional revenue allocations approved for the lighting class.

G. After-Hours Reconnection Charge

i. *Party Positions*

279. NorthWestern proposes to revise its tariff rules to reflect a fee to reconnect electric service after business hours. If approved, Tariff 5-11 would authorize NWE to assess a fee of $150 to a customer choosing to reconnect electrical service outside of business hours (Monday through Friday from 7:30 am to 5 pm). Test. Bobbi Schroeppel at 18 (Sep. 28, 2018).

280. NorthWestern witness Bobbi Schroeppel explains the proposed after-hours fee appropriately assesses the additional cost associated with sending personnel to reconnect services after hours. *Id.* Schroeppel asserts that NWE provides customers multiple opportunities to help them avoid needing an after-hours disconnect. *Id.* She states that due to union contracts, the employee incurs a minimum of two hours of overtime for an after-hours call out and that overtime rate for two hours is the rate being proposed of $150. A rate of $150 per after-hours reconnection, times an average of 2,520 after-hour reconnections, would result in direct costs of $378,000 per year, on average. The Reconnect Charge is designed to recover those direct costs from the customers that cause the costs to be incurred. Reb. Test. Bobbi Schroeppel at 10 (Apr. 5, 2019).

281. Schroeppel further testified that NWE's proposed reconnection charge proposal is consistent with other public utilities' after-hours fees in Montana. Specifically, she cites Montana Dakota Utilities, Fall River Electric Cooperative, Fergus Electric Cooperative Missoula Electric Cooperative, and McCone Electric Cooperative as all having similar charges. *Id.* at 11-13.

282. NWE witness Joseph Janhunen provided information for 2017, stating revenue collections for after-hour reconnects were approximately $49,000. However, he could not state how many actual after-hours reconnects were performed. He indicated the 2017 figure is similar to, but slightly higher than, prior years. This revenue of $49,000 was included in the revenue requirement NWE filed in its application. Hr'g Tr. at 1056-1060.

283. MCC witness Dismukes states that NWE, beyond its statements concerning its practice of handling arrearages, provides no explanation on its current motivations for seeking the proposed tariff change. NWE merely states that it feels it is "appropriate" to assess an after-hour reconnect fee given all of the opportunities it provides its customers with help to avoid needing an after-hours reconnect. Test. Dismukes at 64.

284. Dismukes further states that NWE shows that after-hours reconnection requests have remained steady over the past five years. However, 2018 saw NWE's lowest reported number of after-hours service reconnections in the past five years, just 1,461. Furthermore, Dismukes asserts the Commission should recognize the small percentage of reconnection requests that are placed after-hours currently. Over the past five years, there have been an average of 2,520 after-hours requests annually. During the same period, NWE has averaged 13,879 total service connections annually. This means that after-hours reconnection requests account for less than 18.2% of all reconnection requests. In 2018, after hours requests accounted for slightly more than 10.6% of all reconnection requests, nearly as low as a tenth. *Id.*

285. Dismukes recommends that the Commission reject the proposed $150 reconnection charge. He argues the proposal is a solution in search of a problem. After-hours reconnections are a small fraction of total service reconnection requests, and there is no noticeable trend in the occurrence of such requests. In short, there is no evidence that suggests that after-hours reconnection requests are any more of a problem now than in past years wherein the Company operated without such a fee, with little incident. *Id.* at 65

286. MCC does not believe a reconnection fee is necessary and would simply add to NorthWestern revenues. Dismukes also states the stipulation was accepted without certainty as to the reconnection fee. *Id.* at 2154. When asked if all customers would pay for the expenses if NorthWestern does not charge an after-hours reconnect fee to the customers requesting that service, would all customers pay for those expenses, Dismukes responded, "That's correct." He states their objection has less to do with the philosophy of charging customers, but rather feels the rate is arbitrary and unsupported. *Id.* at 2176-2177.

ii. ***Commission Finding***

287. The information provided by NorthWestern is confusing. For example regarding the $49,000 in 2017 after-hours revenue referenced by Janhunen at the hearing, it was not explained how many customers were charged an after-hours reconnect charge or what rate was charged. If the existing average annual cost to NWE for after-hours reconnects is $378,000, in the absence of an approved tariff, one must assume the costs are being recovered from existing ratepayers. If the after-hours charge was approved, generating $378,000 in annual revenue, should rates for the ratepayers covering those costs be reduced? NWE did not file any proposal regarding the issue of $378,000 of additional revenue from the reconnect charge.

288. The Commission finds the NWE proposal insufficient to support the approval of the after-hours reconnect charge. The Commission rejects NWE's proposal to implement an after-hours reconnect fee of $150.00. Furthermore, NWE shall cease, within 30 days of the date of this order to charge an after-hour reconnect fee in the absence of an approved tariff.

289. NWE is certainly free to refile with the Commission an after-hours reconnect charge proposal. Such a proposal must explain how NWE was apparently charging customers for the service in the absence of an approved tariff, and provide the annual revenue from the after-hours reconnects fee, the rate charged, and the numbers of customers charged for the service. In addition, a filing must address the issue of how are the associated costs of the service currently recovered from the general body of ratepayers, and what rate adjustment would NWE propose to reduce rates for the ratepayers currently paying for the after-hours reconnect costs if the proposed after-hours reconnect charge will generate $378,000 in annual revenue.

H. Ancillary Tariff Revisions

i. ***Party Positions***

290. NorthWestern proposes to make changes to tariff Rule Nos. 1, 3, 5, 6, 2 7, 8, and 13. NorthWestern provided red-lined versions of the proposed tariff revision. A description of the proposed changes for each of these tariff rules follows. Test. Schwartzenberger at 23-28.

- *Rule No. 1*

291. NorthWestern proposes to add a definition for "Loads of Uncertain Duration" at ¶ 1-6 for clarification purposes and to coordinate with changes proposed in tariff Rule No. 5 as discussed below.

- *Rule No. 3*

292. The proposed changes to ¶ 3-1 acknowledge that there are instances when the utility requires a service agreement (a new service, for example) and instances when it does not (activating an existing service, for example), and clarifies customers' obligations.

- *Rule No. 5 (excluding Rule No. 5-11 discussed above)*

293. The first proposed change in ¶ 5-2 is for clarification. The second change in that paragraph is to clarify who owns the easement and it reflects current practice. The first proposed change in ¶ 5-3 is for clarification, acknowledges that a service agreement is not always required, and is consistent with the proposed change to ¶ 3-1 in Rule No. 3, explained above. The change proposed at the bottom of ¶ 5-3 adds a cross-reference to related provisions in ¶ 8-2 B in Rule

No. 8. NorthWestern proposes to delete ¶ 5-4 C because it is obsolete. The proposed changes to ¶ 5-6 E are for clarification purposes. The changes proposed in the title of section 5-7 and first part of ¶ 5-5 coordinate with the definition of "Loads of Uncertain Duration" proposed on Rule No. 1 as discussed above. The change at the bottom of the paragraph specifies that proposed new ¶ 5-11 applies to Loads of Uncertain Duration. The changes to ¶ 5-7 B are for clarification purposes. The change in ¶ 5-9 B.1.a. is for clarification purposes and reflects NorthWestern's current practice. The remaining changes in ¶ 5-9 are for clarification purposes.

- *Rule No. 6*

294. NorthWestern proposes to adjust the residential line extension allowance in ¶ 6-1 A from the current flat rate of $500 to $400. This allowance is based on multiplying the applicable proposed base transmission and distribution rates by the average annual residential customer energy usage. Refer to Exhibit JS-6, ln. 29, Column B. In sections 6-1 B 1 and 2, the tariff requires that the extension allowances for the General Service and Irrigation demand and non-demand customers be determined by multiplying the applicable allowance rates (specified in the tariff) by NorthWestern's estimate of the annual kWh consumption of the customer. The proposed allowance rates are also computed on Exhibit__ (JS3 6). For the non-demand classes, the applicable transmission and distribution revenues are totaled and divided by the total load for those classes. The resulting proposed non-demand General Service and Irrigation allowance rate is $0.05 shown at line 30, Column B in Exhibit__ (JS-6). The current rate is $0.04. The computation for the demand classes is the same. As shown at 8 line 31, Column B, the proposed demand General Service and Irrigation allowance rate is $0.04, the same as the current rate for these customers. Recognition of one year of revenues as an allowance against line extension costs for these General Service and Irrigation customers is consistent with the treatment of Residential customers. The proposed addition at the end of § 6-2 and new § 6-14 reflect Senate Bill 374 passed by the 2017 Legislature and codified in Mont. Code Ann. §§ 69-17 5-121, 69-5-122(4)(c), and 69-5-123. The addition to the second paragraph under § 6-6 A is for purposes of clarification. The update to the hourly rate in section 6-6 D is the Supervisor/Engineer hourly rate included in NorthWestern's 2018 Movement of Structures Cost Schedule submitted in Docket No. N2018.1.3. NorthWestern engineers develop the estimates for line extensions.

- *Rule No. 7*

295. There are two proposed changes. The first corrects the code title in the last line of § 7-1. NorthWestern proposes the change to § 7-4 A to update a very specific dated lighting-related power factor requirement to a more broad-based current practice power factor requirement. In the early days of inefficient ballast type fluorescent lighting, tariff language specifying a minimum power factor of 90% ensured that customer lighting equipment would perform to the common minimum acceptable power factor of 90%. This proposed change replaces the specific lighting performance requirement with a general customer equipment requirement to operate above 90% power factor, which is still considered the common minimum acceptable level at or above which supplemental power factor correction methods are not required.

- *Rule No. 8*

296. The proposed changes are minor corrections and clarifications.

- *Rule No. 13*

297. NorthWestern proposes to update § 13-11 to reflect Mont. Admin. R. 38.5.1411. The regulation was substantially revised by the Commission in 2010. NorthWestern has not filed an update to Rule No. 13 to reflect the Commission-approved regulation. This was unintentional. NorthWestern's practice has, however, been compliant with the revised rule. The proposed change to ¶ 13-16 is necessary so that NorthWestern is able to comply with the first part of the rule, which requires the Utility to determine if a tenant occupies the residence. Finally, NorthWestern proposes to update the NorthWestern logo on all sheets of Rule No. 13.

ii. ***Commission Finding***

298. The revisions to tariff Rules Nos. 1, 3, 5, 6, 2 7, 8, and 13 described above were uncontested in this docket. The proposed minor tariff revisions discussed above are approved.

III. Other Contested Issues

299. The Commission addresses several additional unresolved issues below, including: several issues related to NorthWestern's ownership in CU4; NorthWestern's DSM programs; the MCC's request for a jurisdictional cost-of-service study; and the elimination of NorthWestern's Spion Kop annual compliance filing.

A. Colstrip Issues

i. *Background*

300. Colstrip is comprised of four generation units owned by a variety of utilities and merchant generators. NorthWestern currently owns a 30% interest in CU4. The various units, ownership interests, and expected closure dates and depreciation schedules are provided below:

XXI: Colstrip Ownership

Percent Ownership				
Generation Unit	CU1	CU2	CU3	CU4
Nameplate Capacity	358	358	778	778
Puget Sound	50%	50%	25%	25%
Portland General	0%	0%	20%	20%
Avista	0%	0%	15%	15%
PacifiCorp	0%	0%	10%	10%
Talen	50%	50%	30%	0%
NorthWestern	0%	0%	0%	30%

XXII: Colstrip Scheduled Closure Dates and Depreciation Schedules

Scheduled Closure (CU1/CU2) and Current Depreciation Schedules (CU3/CU4)				
Generation Unit	CU1	CU2	CU3	CU4
Puget Sound	2019-2020	2019-2020	2027	2027
Portland General	N/A	N/A	2030	2030
Avista*	N/A	N/A	2027	2027
PacifiCorp	N/A	N/A	2027	2027
Talen	2019-2020	2019-2020	N/A	N/A
NorthWestern	N/A	N/A	N/A	2043

*On November 21, 2019 Avista Corporation announced, as part of a partial settlement agreement between Avista and multiple intervening parties in the utility's general rate case in Washington State, that it is financially ready to exit Colstrip Units 3 & 4 by 2025.

301. NorthWestern acquired 79.29 MW of CU4 on March 31, 2007, from Mellon Leasing for $58.6 million. On October 30, 2007, NorthWestern acquired an additional 142.71 MW of CU4 from SGE for $128.4 million. As a result of these transactions, NorthWestern owns 222 MW, a 30% share, of CU4, for which it paid $187 million. At the time of those transactions, NorthWestern asserted its CU4 interest was not public utility property subject to Commission jurisdiction, but rather was subject to FERC jurisdiction as wholesale merchant generation.

302. In early 2008, NorthWestern hired Credit Suisse Securities to evaluate and determine the fair market value of CU4 through a competitive sales process. Eleven parties submitted initial bids and seven bidders were selected to participate in Phase 2 of the process. Four Phase 2 bids were received ranging from $360 million to $404 million. Bicent Power was selected as the winning bidder with a bid of $404 million and a sale transaction was announced on June 10, 2008. Bicent Power, a subsidiary of Beowulf Energy, was a special-purpose operating company formed in 2007 to acquire independent power producers.

303. On June 27, 2008, NorthWestern filed a request for Commission preapproval to include the 222 MW of CU4 as a retail electricity supply resource with a rate base of $407 million. *In re Colstrip Pre-Approval,* Dkt. D2008.6.69. The rate base figure of $407 million included the Bicent bid of $404 million, $6.25 million for termination fees, and ($3.25) million in avoided transaction costs. During the proceeding, NorthWestern indicated that as of November 30, 2007, shortly after the SGE acquisition, the original cost plant balance for its share of CU4 was $67,277,872, the associated depreciation reserve was $29,735,530, and net book cost was $37,542,342. DR MCC-019.

304. MCC testified in the preapproval proceeding that the Commission had the option of rate-basing the CU4 interests at $37.5 million, in addition to, if warranted, such portion of the acquisition premium of $149.5 million ($187 million less the $37.5 million in net book) that NorthWestern establishes to be appropriate and in the public interest. Thus, the MCC opposed NorthWestern's $407 million rate base proposal and instead advocated for a rate base ranging from $37.5 to $187 million.

305. On November 13, 2008, the Commission approved rate basing NorthWestern's share of CU4 at $407 million, which was reflective of the bid-based market value. Order 6925f, Dkt. D2008.6.69, ¶ 251 (Nov. 13, 2008) The Commission also approved, for the life of the plant, a 10.0% return on equity ("ROE"), a 6.5% cost of debt, and a 50% equity/50% debt capital structure. *Id.* ¶ 264. This equates to an overall allowed return for the life of the plant of 8.25%.

306. NorthWestern's Application presented a CU4 revenue requirement and rate base which continues to reflect the market transaction-based plant value the Commission approved in Docket D2008.6.69 (the preapproval case). Statements C and D of NorthWestern's Application show the following plant balances on NorthWestern's regulatory books as of December 31,

2017, for CU4 was $303,981,607. This reflects the $334,240,518 Net Book cost less deferred taxes.

XXIII: CU4 Plant Balances

	Plant Balance (Orig. Cost)	Accumulated Depreciation	Net Book Value
Intangible Plant	$335,889,309	$66,071,683	$269,817,626
Generation Plant	$88,031,667	$23,608,775	$64,422,892
Total	$423,920,976	$89,680,458	$334,240,518

307. The $335.9 million in Intangible Plant is the difference between the original cost for CU4 plant on the books and the approved rate base of $407 million. The Intangible Plant amount has been booked to FERC Account 114 – Electric Acquisition Adjustment. This amount does not change over time; it is the same amount that was originally recorded when rate basing was approved in the preapproval case.

308. In June 2019, Talen Energy Corporation and Puget Sound Energy announced early retirement of Colstrip 1 and 2, which are scheduled to be retired by the end of 2019.

ii. ***Party Positions***

309. The parties request a variety of Colstrip-related actions, including: addressing remediation costs; open an investigation docket to consider various Colstrip-related retirement, remediation, and transition fund costs; and establish additional reporting requirements. Each issue is discussed in more detail below.

- *Investigate Docket to Establish Remediation Costs*

310. MEIC requests the Commission to require NorthWestern set aside funds sufficient to satisfy federal and state regulatory requirements to remediate groundwater contamination caused by the plant's coal-ash waste impoundments and appropriately close those impoundments.

311. Additionally, HRDC/NRDC witness Power testifies that the CU4 related plant costs typically would be recovered in NorthWestern's revenue requirement through depreciation. A depreciation rate is set based on the projected life of the plant and the plant costs are reduced each year by the annual amount of the depreciation. This allows shareholders to recover their initial investment and earn a return on the undepreciated balance. It also ensures that customers do not overpay and that customers receiving electricity from the asset are the customers paying the costs.

312. Regarding retirement costs, Power explains that they are costs to mitigate or remediate environmental damage caused by the operation of the facility over its lifetime. Such costs are typically recognized as utility liabilities and recovered from customers over the life of the plant. These costs are added to the utility's rate base and then recovered in a utility's annual depreciation expense. Power states that an Asset Retirement Obligation ("ARO") is created when the legal requirement to mitigate any environmental damage is recognized. AROs are included in the cost of removal associated with plant decommissioning and are recovered through depreciation rates, which also take into account any salvage value at the time of retirement. The difference between the cost of removal and the salvage is termed "net salvage."

313. Power asserts that retirement costs at the time of a generator's retirement should be relatively small if the depreciation rates over the life of the plant have properly and accurately included the ARO costs.

314. Power states there is a risk that when CU4 closes, NorthWestern will not have collected sufficient money from customers to cover plant costs and the costs of removal, including remediation. If CU4 closes within the next decade there will be a significant amount of unrecovered plant investment which NorthWestern will wish to recover from customers even though those customers will not be receiving electricity from the units.

315. Regarding the regulatory treatment of environmental cleanup costs, Power testifies that the combustion of coal produces a variety of pollutants that have to be removed from the exhaust of electric generators. This produces an ongoing flow of solid and liquid wastes, called coal combustion residuals ("CCR"), which are recovered and moved to storage ponds. There is no consensus as to what remediation regarding CCR should entail. Thus, it is unclear right now what a solution might cost. DEQ has estimated the remediation cost for the entire Colstrip facility at $400 to $700 million. Power states that NorthWestern has not addressed remediation, cost of removal, or decommissioning costs in this rate case, and he believes such an approach is risky. If CU4 is forced to shut down without the issue of cleanup costs being dealt with, there will be significant environmental and decommissioning costs, none of which will have been recovered from customers.

316. Regarding, the risk associated with the early closure of CU4, Power states that, while NorthWestern has a 2042 retirement date for CU4, Puget Sound Energy has set a date of 2027, as established in UE-170033. Avista, in Idaho and Washington, has also set a date of 2027,

and Portland General Electric a date of 2030. Finally, PacifiCorp, in Docket UM-1968 before the Oregon Commission, is seeking to move the depreciable life of Colstrip Units 3 and 4 from 2032 to 2027.

317. Accordingly, Power recommends that the Commission, as soon as possible after the conclusion of this rate case, open a CU4 docket in which all issues related to Colstrip will be examined. He maintains this is an important issue and urges the Commission to address it by playing an active role in finding a solution to the problem.

318. In response, NorthWestern witness Lail states that while NorthWestern recognizes the need for planning for those costs, NorthWestern did not request and does not support setting rates for the recovery of those costs in this rate case. She asserts those costs should be considered when a shut-down date for CU4 is established. Reb. Test. Lail at 28. Additionally, NorthWestern notes that an ARO was established by NorthWestern related to its legal obligations related to CU4's ash ponds. NorthWestern has recorded this liability in its GAAP books, but the costs are not included in its regulatory books for cost of service ratemaking, because NorthWestern is not seeking recovery of those costs in this case. *Id*. at 29. "Consistent with established ratemaking principles," Lail testified, "when retirement obligation costs are determinable following establishment of an agreed-upon shut-down date and remediation methodology, NorthWestern will request Commission approval of recovery." *Id.* Lail asserts, using Puget Sound Energy as an example, that until a shut-down date is established and a remediation plan is agreed upon by all parties, including the DEQ, that a liability is not determinable. *Id.* at 32.

319. Accordingly, Lail stated that she does not believe it is necessary to have a Colstrip-specific investigation docket, as NorthWestern plans to operate the facility through the end of its useful life and will seek to recover any unrecovered costs in a future rate case. Hr'g Tr. at 717. This testimony is consistent with NorthWestern's position in the preapproval docket for CU4, in which it indicated that it would seek to recover future costs related to CU4, such as remediation costs, in a future proceeding. *In re Colstrip Preapproval,* Dkt 2008.6.69, Order 6925f, ¶ 43 (Nov. 13, 2008) ("These costs will be legitimate operating and capital costs" that NorthWestern expects to recover "as part of CU4 future generation costs.").

320. In contrast with Lail's testimony, NorthWestern witness Hines supports the Commission opening an informational docket regarding Colstrip-related issues, but only if the docket is part of a non-contested case proceeding. Hr'g Tr., 2467–2468. Hines testified on re-

direct that he believes that if the Commission opens a separate docket, it needs to be "thoughtful as to what sort of information that they're going to be wanting to solicit and what's already available, and in the context that some parties are likely to use that for furthering litigation." Hr'g Tr. at 2528.

- *Community Transition Funds*

321. Both Northern Cheyenne and MEIC/SC request the Commission to require NorthWestern to contribute $4.5 million to an interest-bearing account to support Colstrip community and worker transition in preparation for the eventual closure of CU3 and CU4.

322. MEIC/SC provides several reasons why transition funding is necessary.

323. Transition funds are needed for worker retraining, economic redevelopment, and clean energy development: "The City of Colstrip, the workers employed by Colstrip, and the surrounding community, are situated in a remote region of Montana and are dependent on the operation of Colstrip. This makes the Colstrip community acutely vulnerable to changes in Colstrip operation, especially plant retirement." Test. Binz at 45. MEIC witness Ronald Binz pointed out that Colstrip owners are reaping the benefits the local workforce provides and that some of the earnings should be channeled to ensure a fair outcome upon transition. *Id.* at 46.

324. Binz also testified that Colstrip owners in Washington have already created a fund to mitigate the impact of closing CU Units 1–4. *Id.* at 46. For example, he noted Puget Sound Energy's settlement in Washington State in which Puget Sound Energy agreed to provide $10 million for Colstrip transition. *Id.* at 47. Binz suggested that collecting community transition funds now would allow for interest to accrue until the funds are needed, without influencing retirement date. *Id.* The community can plan for expenditures of the funds ahead of time, rather than waiting for the plant to close. *Id.* Binz testified that providing community transition funds supports intergenerational equity, meaning that future customers who do not benefit from Colstrip are not forced to pay for retirement costs. *Id.* at 47.

325. Accordingly, MEIC/SC recommends NorthWestern set aside $4.5 million for community transition funding for the CU4 closure. *Id.* at 48.

326. Binz explained that if the Commission declines to reevaluate the CU4 asset as he has recommended, the community transition costs should not impose additional requirements on current customers. He explained that if the Commission adopts his primary recommendation regarding CU4, the Commission will have returned to cost of service regulation, and he

recommends the community transition funds be added to rates. *Id.* at 48. Binz also proposes using excess accumulation of deferred taxes (EADIT) to pay for the community transition fund. *Id.* at 48.

327. Binz pointed out that Colorado just passed legislation to include transition funds in retirement plans. Hr'g Tr. at 2089. He acknowledged transition planning funds are relatively a new issue regarding plant retirements, but notes that there is precedent in Montana with the practice. *Id.*; *see generally In re Avista/Hydro-One Merger,* Dkt. D2017.9.71, Order 7577a (Jun. 12, 2018). Relatedly, Binz testified that securitization to retire the debt in power plants would create savings that could then be dedicated to transition funds. *Id.* at 2090.

328. Northern Cheyenne provides several reasons for why transition funding is necessary. William Walksalong testifies that jobs at Colstrip are central to the tribal economy. He states there are over 100 tribal members who work at the power plant and mines. He asserts that each of those jobs directly supports approximately 10 members such that the operation of the power plant directly benefits more than 1,000 tribal members or 10% of the on-reservation population. Test. William Walksalong at 7 (Feb. 12, 2019).

329. Walksalong also maintains that Colstrip and associated coal mines have both positive and negative impacts on the surrounding communities. The Tribe and its members are disproportionately reliant on those benefits and disproportionately harmed by the negative impacts such as air and groundwater pollution, crime, and lower quality of life. *Id.* at 9.

330. Walksalong states that it is his understanding that part of NorthWestern's rate-setting process involves future planning for CU4 closure, including how to account for the costs of operations, closure, and remediation. He asserts he is aware of rate-setting cases for Puget Sound Energy and Avista in which there have been substantial settlements that purport to compensate communities impacted by plant closures. Walksalong asserts the Tribe has been shut out of those processes in Montana and was not invited to be a member of the Governor's Colstrip Community Impact Advisory Group. *Id.*

331. Walksalong asserts that NorthWestern should not be allowed to benefit and profit from operations near the Reservation and then leave the Tribe and its members to bear the consequences of closure. Any plan must seek to minimize impacts on tribal members and compensate for the impacts that occur including environmental and economic impacts.

332. This can be accomplished by prioritizing and giving employment preference to tribal members; employ as many tribal members as possible; assist the Tribe and the region in a transition to renewable energy to replace coal and buy the electricity generated by renewables at above-market rates; and by offering greatly reduced transmission costs to buyers. Test. Walksalong at 10–11.

333. Walksalong states NorthWestern should give job prioritization to tribal members for closure and remediation. In addition, he asserts that NorthWestern should assist the Tribe and the region to transition to renewable energy sources that replace coal by agreeing to buy power at above-market rates and by offering greatly reduced transmission costs to outside buyers. Finally, Walksalong suggests that NorthWestern should fund a $4.5 million transition fund. *Id.* at 11.

334. Walksalong arrived at the figure of $4.5 million because that is the settlement amount Avista agreed to as part of its acquisition by Hydro One. Avista owns 15% of CU3 and 15% of CU4, which is equivalent to NorthWestern's 30% ownership in CU4. Walksalong indicated the $4.5 million payment is proportionate to a $10 million settlement paid by Puget Sound Energy. Test. Walksalong at 11.

335. Regarding community transition funds, NorthWestern witness John Hines states the recommendations are premature and focused on the wrong party. He asserts that there is not enough information in this docket that can be used to ascertain the reasonableness of these demands. Regarding the idea of providing the Tribe with subsidized power purchase rates for purchased power and transmission costs, Hines states NorthWestern is bound by law to comply with its tariffs, which in general ensure all customers are economically indifferent. Regarding a transition fund, Hines states that he believes that at this time the Sierra Club should be a responsible party for payments to the Tribe. Hines asserts that NorthWestern wants to continue operating Colstrip because it is a cost-effective and necessary piece of its generation portfolio.

- *Additional Reporting Requirements*

336. MEIC/SC and HRDC/NRDC recommend the Commission require additional reporting requirements on a variety of Colstrip-related issues.

337. HRDC/NRDC recommends that the Commission require NorthWestern to file a Colstrip status report every six months or annually. *See* Hr'g Tr., at 2007–2008. The status report would provide the most recent information concerning remediation for Units 3 and 4, including

cost estimates, and would report, to the extent known, on the plans of the other utilities with respect to their interest in Colstrip Units 3 and 4. Test. Power at 85.

338. MEIC/SC recommends the Commission require NorthWestern to report annually on the time frame for retirement of both Colstrip Units 3 and 4 and NorthWestern's estimates of the costs associated with those retirements. Reporting should include: (1) the appropriateness of current depreciation rates and updates on its estimates of cost of environmental remediation associated with the retirement of Colstrip Units 3 and 4; and (2) NorthWestern should provide notice to the Commission of any significant findings or events that alter the projections of the operating life of Colstrip Units 3 and 4 within 30 days of the occurrence of such findings or events. The notice should also contain NorthWestern's analysis of the impacts and its plans to address them.

339. Hines states NorthWestern is opposed to MEIC/SC recommendations to require NorthWestern to provide regular reports regarding Colstrip's closure costs and operating life or to initiate a new docket to address all issues related to Colstrip. Reb. Test. Hines at 17. Hines asserts that, given the political attacks on coal-fired generation, the Commission should be concerned about Colstrip's future. He states that MEIC and Sierra Club are unequivocal in their desire to close Colstrip and that the Sierra Club brags on its website that 286 coal plants are scheduled to be retired or already are retired and only 244 are left to go. Hines states that at this time NorthWestern has no plans to close Colstrip, so it is premature to open a docket regarding its closure. *Id*.

iii. ***Commission Finding***

340. The Commission declines to initiate a Colstrip investigation docket, require additional Colstrip reporting, or require NorthWestern to commit to community transition funds at this time.

341. The Commission's earlier decision on the revenue requirement stipulation Paragraph No. 11 forecloses the Commission from addressing NorthWestern and intervenor arguments to amend Colstrip's rate base. This included both increasing Colstrip's rate base by $42 million in CU4 capital expenditures since 2008, as requested by NorthWestern, and reducing Colstrip's rate base to MEIC/SC's estimated $100 million current market value. The Commission decided it was unreasonable to address those issues for two reasons. First, because the revenue requirement settlement provided only an aggregate $6.5 million total revenue

requirement increase, it would be inappropriate to consider one specific generation-related rate base element in isolation from not only the various generation-specific revenue requirements (CU4, DGGS, Spion Kop, hydro assets, Montana generation, and non-PCCAM), but also the non-generation-specific revenue requirements (transmission and distribution, and Two Dot). Second, because the Commission determined that the settlement provision was only an information statement between the parties which did not require further Commission action.

342. However, intervenor requests to establish an investigation docket regarding various Colstrip-related issues, to require NorthWestern to provide certain annual reports to the Commission, and to generally consider community transition funding, are all unresolved. As discussed below, although the Commission believes each issue has merit, the Commission declines to address each request at this time.

343. There are at least two reasons why Commission action on any of these issues is prudent. For example, the Commission lacks sufficient information on a variety of issues. NorthWestern's current depreciation schedule for CU4 is significantly longer than those currently in place for the remaining CU4 owners. As discussed above, the other Unit 3 and 4 owners have depreciation schedules which are exhausted at latest by 2030. NorthWestern's current 2043 deadline, particularly when viewed in the context of the company owning just 30% of one unit, casts significant doubt regarding the operation of Colstrip beyond 2027 or 2030. This operational concern supports Commission action on a variety of Colstrip-related issues. This risk is underscored by the fact that, even though Puget Sound and Talen had previously agreed to retirement dates of 2022 for CU1 and CU2, in June of this year the companies announced retirement of both assets by 2020 due to unfavorable economics. This decreases confidence in even a 2027 or 2030 retirement date for the remaining generators. An investigation docket or annual reporting requirements could provide the Commission with valuable information regarding this significant operational risk. An investigation or additional reporting requirement would also inform important, insufficiently understood, Colstrip-related concerns, such as transition funding, potential remediation costs, allocation of liability, and future generation asset sales or purchases that could impact NorthWestern's CU4 ownership interest.

344. Second, intergenerational inequity concerns are present. Customer rates should reflect costs associated with utility plant that remains in service, and should limit costs for goods or services which does not. This ensures intergenerational equity: each generation of customers

are charged for services based on the costs of the services they receive, as opposed to costs from preceding or succeeding generations. To do otherwise causes inequity because generations pay for goods or services that are either no longer in service (depreciation schedules extending beyond the operational life of an asset, or paying for cleanup costs from retired generation assets), or have yet to be placed in service (advancing funds used for large capital projects such as construction of new nuclear generation assets, which take several years, or decades, to finish).

345. There are at least two intergenerational equity issues presented. First, without Commission action, if CU4 closes earlier than 2043, customers could continue paying for NorthWestern's undepreciated CU4 rate base even though the asset is no longer in service. Given the large differences in depreciation schedules (2027 to 2043), and large net book rate base value ($334 million as of Dec. 31, 2017), the customer impact could be substantial.

346. Second, without Commission action, succeeding generations could pay for cleanup costs associated with CU4 after the asset is no longer in service. NorthWestern has represented it is not presently recovering from customers any revenue for liabilities associated with CU4, and does not believe it necessary to do so until a retirement date has been established. This includes currently known liabilities (CU4 ash ponds), or potentially unknown liabilities. As the currently known liabilities ($400-$700 million estimated liability between all owners) are substantial, yet NorthWestern is not recovering cleanup costs from current customers, and with no firm CU4 retirement date, it is likely that customers will pay for cleanup costs after a CU4 retirement. An investigation docket could mitigate these two intergenerational equity issues.

347. There are also at least three reasons why action is not prudent at this time. Actual remediation costs, apportionment of liability, and retirement dates are unknown. Although NorthWestern has established an ARO regarding its current coal ash pond liability for GAAP purposes, NorthWestern's exact liability is unknown. Additionally, there is no uniformly adopted retirement date for either CU3 or CU4. While the Commission could require NorthWestern to begin recovering in rates Colstrip-related remediation costs, not only would the amount of remediation costs be speculative, but so would the proper timing of rate recovery given the undetermined retirement date. The Commission also notes that this is a multi-jurisdictional issue, potentially involving not just various state agencies (DEQ and the Commission, for example), but also various federal agencies as well (the United States Environmental Protection Agency). This further supports delaying action on this issue.

348. Additionally, there are alternative remediation financing mechanisms being developed. During the 2019 legislative session, the Legislature passed the Montana Energy Impact Assistance Act. HB 467, *codified at* Mont. Code Ann. §§ 69-3-1601 through -1623. Generally, this bill allows utilities like NorthWestern to issue bonds to recover costs associated with retirement, replacement, or remediation of electric generation assets. The Commission is directed to adopt rules to implement this Act. Mont. Code Ann. § 69-3-1604. This mechanism could provide a viable alternative to traditional cost of service ratemaking to address any remediation and retirement costs associated with NorthWestern's ownership interests in CU4. It could be beneficial to delay a Commission investigation until after this rulemaking has concluded, to ensure the Commission has a broad range of available mechanisms to address Colstrip-related remediation and retirement costs.

349. Although the Commission declines to initiate a Colstrip investigation docket as the result of this current docket, The Commission notes that it retains the authority to initiate a non-contested case proceeding (*see generally* Mont. Code Ann. §§ 69-3-102, -103, -106), or a contested case proceeding (Mont. Code Ann. §§ 69-3-324, -330) to investigate these issues when it determines it is necessary to do so. Interested parties also have the right to request the Commission to initiate an investigation into these concerns under Mont. Code Ann. § 69-321 at any time.

350. Finally, of very recent note, NorthWestern announced it is seeking approval to acquire Puget Sound's 25% share in CU4:

> NorthWestern Energy will file an application for pre-approval with the Montana Public Service Commission to acquire Puget Sound Energy's 25% interest, 185 megawatts of generation, in Colstrip Unit 4 for one dollar. In late January or early February, NorthWestern Energy will submit an application for pre-approval of the acquisition of the 185 megawatts to the Montana Public Service Commission. In addition, NorthWestern Energy will seek approval to sell 90 megawatts to Puget Sound Energy for roughly 5 years.

NorthWestern Press Release (Dec. 10, 2019).

351. From the Commission's perspective, there is no doubt that in this new contested case docket, CU4 issues such as retirement dates and stranded costs, remediation costs, and community transition funding will require investigation.

B. Demand-Side Management Programs

i. *Party Positions*

352. Utilities are required by Montana statute to include DSM options in their supply resource planning and procurement processes. Mont. Code Ann. § 69-3-1209. Currently, NWE offers the following programs: E+ lighting for commercial and residential LED lighting, E+ Commercial Programs and Contractors for training and marketing energy efficiency measures to contractors, and E+ Commercial Electric Rebate Program, which includes incentives for motor rewinding.

353. NWE currently uses a total resource cost ("TRC") test to evaluate the cost effectiveness of DSM programs. NWE calculates the avoided cost value of energy saved and the total DSM program costs for its TRC test. NWE explains that carbon cost adders have recently been included in DSM avoided costs, so the 10% environmental benefit adder that was previously included in the TRC is no longer utilized. No carbon adder was included in DSM avoided costs for the 2018-2019 or 2019-2020 program years, based on Commission decisions to not include a carbon cost in avoided cost calculations for qualifying facilities. DSM measures and program lives are also restricted to 15 years to comply with the Commission's Order 7500d in Docket D2016.5.39. Test. Dani Williams, 1-9 (Sep. 28, 2018).

354. NWE initially proposed to remove DSM costs from NorthWestern's electricity supply tracker in Docket D2017.5.39. Rather, NWE proposed to record DSM expenditures as a regulatory asset amortized over a 15-year period. NWE states that Commission rules require NWE to treat DSM as a supply resource, and so it is reasonable for NWE to treat DSM as an investment included in the asset base as capitalization allows NWE to spread large expenditures over a reasonable time without rate fluctuation. Test. Lail at 20-22.

355. NWEC witness F. Diego Rivas does not believe that all cost-effective energy efficiency measures are being pursued by NWE. For example, NWE could be pursuing residential measures such as faucet aerators or smart thermostats, which were identified as cost-effective in NWE's 2016 Electricity Energy Efficiency Market Potential Study. Rivas also believes that NWE is incorrectly using the TRC test to calculate cost-effectiveness of efficiency measures. NWE only uses the avoided cost value of energy saved as the benefit of the measure, while other utilities also include the reduction in transmission, distribution, generation, and capacity costs valued at a marginal cost for the periods where there is a reduction in load. Rivas

suggests that the Commission should either direct NWE to correctly apply the TRC or use the Utility Cost Test ("UCT"), which is the avoided energy and capacity costs plus transmission and distribution benefits, divided by the total program costs. Test. Rivas at 12-25.

356. In response, MCC suggests that if NWE is allowed to defer DSM costs, the amortization of the deferred DSM costs should commence by the end of the year in which the costs are incurred. MCC Witness Ralph Smith also recommends that a $45 million threshold should be set for DSM deferral costs, to prevent accumulation of large amounts between rate cases. If the threshold is reached, it would trigger a requirement for NWE to make a filing with a Commission that includes a plan for cost recovery. Test. Ralph Clark at 78-82 (Feb. 12, 2019).

357. MCC witness David Dismukes explains that NWE provided few details on its DSM proposal, including how it proposes to defer its annual DSM expenses, whether or not any return will be included with the expenses booked, or whether or not deferred investments will be amortized prior to the ultimate incorporation into rate base. There is also no cap on deferred costs or the ultimate size of the proposed regulatory asset. Dismukes recommends that the Commission continue to incorporate annual DSM expenses through the PCCAM, without being subject to the deadband or sharing percentages. Test. Dismukes at 26-29.

358. In reply, NWE witness Crystal Lail states that NWE is not opposed to keeping the DSM costs in the PCCAM, as long as recovery is 100% and not subject to the deadband and sharing percentages. NWE is opposed to starting the amortization of deferred DSM costs at the end of the year in which the costs are incurred. Lail explains that Commission practice in Montana has been to begin depreciating assets in the year following the year the assets are placed into service. NWE opposes Smith's suggestion to implement a $45 million threshold for accumulated deferred DSM costs. Reb. Test. Lail at 18-20.

359. Additionally, NWE witness Danie Williams states that NWE did not revise its DSM acquisition target due to the Commission's decision to discontinue the lost revenue adjustment mechanism, but rather as a result of the Electricity Energy Efficiency Market Potential Study conducted by Nexant, Inc. That study showed more robust potential efficiency programs than what NWE implements in Montana, because NWE tries to focus on DSM programs that simplify offerings and set rebates at levels that drive customer participation. Administrative and promotional costs, which can often outweigh benefits, would not be cost-effective. Reb. Test. Danie Williams at 2-3 (Apr. 5, 2019).

360. Williams explains that NWE discontinued its DSM programs for residential electric customers, with the exception of lighting, because the programs were not cost-effective. In NWE's Montana service territory, residential measures tend to result in relatively small per-customer energy savings. Williams states that the avoided cost for DSM has decreased since the Nexant study, from $40.70/MWh to $37.57/MWh, which decreases the margin available to absorb administrative costs. *Id*. 5

361. Williams states that an Electric Potential study was completed by Nexant in 2017, and updates are expected to be completed in 2019. That study provides information to calculate capacity contribution for DSM resources. *Id*. 7

ii. ***DSM Stipulation***

362. On May 20, 2019, the Commission received a Stipulation between NWE and the NWEC regarding capitalization and amortization of DSM costs. The following two Stipulation paragraphs require a Commission decision:

> ¶1. The Stipulating Parties agree that NWE will create a small (no more than 10 people), advisory stakeholder group consisting of relevant and appropriate stakeholders selected by NWE, which shall include at minimum representatives from the NWEC, the MCC, and Commission staff, to discuss re-envisioning of the electric DSM programs offered by NWE for the 2020-2021 program year (items to be discussed include branding, methods of marketing, cost-effectiveness calculations, and energy savings estimates). The group shall make recommendations to NWE for consideration in the development of the 2020-2021 electric DSM program offerings. Once the 2020-2021 program year commences, the group shall be disbanded. The Stipulating Parties will also include a 10% adder for electric DSM in its cost-effectiveness calculations beginning with the 2020-2021 program year, unless a different adder is required by Montana Administrative Rules and continue its work towards including a capacity value of electric DSM measures and/or programs in cost-effectiveness calculations."
>
> ¶2. With regard to recovery of electric DSM expenditures, the Stipulating Parties agree that NWE shall record any DSM expenditures as a regulatory asset in the year the expenditures are incurred. NWE shall also amortize these DSM expenditures over 10 years starting coincident with the Commission order that approves the expenditures for inclusion in rates at which time NWE will earn a return of and return on all electric DSM expenditures at the Rate of Return approved by the Commission, including any adjustment to Return on Equity ("ROE") for conservation investments pursuant to Montana Code Annotated Title 69, chapter 3, part 7. The Stipulating Parties agree that there should not be a threshold level of the DSM regulatory asset that triggers the need for a filing by NWE.

iii. ***Commission Finding***

363. The Commission rejects the DSM Stipulation. However the Commission finds merit in ¶ 1 of the Stipulation, regarding creation of a DSM stakeholder group. The Commission also continues the current practice of allowing NorthWestern to recover DSM expenses through NorthWestern's annual electricity supply cost tracker.

364. First, the Commission orders NorthWestern to create the stakeholder group provided for in ¶ 1. This paragraph proposes a stakeholder group to make recommendations on electric DSM programs, to which no party objected. The Commission is concerned that the timeframe for the stakeholder group to complete its work prior to the commencement of the July 1, 2020-2021, DSM programs may be too short. To address this concern, by May 1, 2020, NWE shall report to the Commission regarding the progress of the stakeholder group and an assessment of the probability of being able to include the stakeholder recommendations in NorthWestern's 2020-2021 DSM program offerings. NWE may request an extension at that time to incorporate stakeholder group recommendations into the 2021-2022 DSM program year rather than the 2020-2021 program year.

365. Second, the Commission rejects a 10% adder for DSM cost-effectiveness in its TRC cost tests. The final sentence of Paragraph 1 addresses the incorporation of a 10% adder for electric DSM in NWE's cost-effectiveness calculations, beginning with the 2020-2021 program year. Prior to the 2015-2016 DSM program year, NWE used a 10% factor to evaluate environmental benefits based on the Northwest Power Act of 1980, which states that conservation measures should be evaluated at 110% of the cost of an alternative resource. In the 2015-2016 DSM program year, NWE discontinued the 10% factor in favor of a carbon cost adder in its DSM avoided costs calculations, based on the Carbon Penalty Forecast in its Electricity Supply Resource Procurement Plan. This translated to a carbon price of $21.11/metric ton beginning in 2021 (and escalating at 5% annually) for the 2015-2016 DSM program year, and $20.00/metric ton beginning in 2022 for the 2016-2018 DSM program years. No carbon adder was included in DSM avoided costs for the 2018-2019 or 2019-2020 program years, based on Commission decisions to not include a carbon cost in avoided cost calculations for qualifying facilities.

366. The Commission further rejects the use of the UCT in this docket, however the Commission does recommend that the UCT, inputs to the TRC test, and any other potentially

appropriate cost-benefit tests should be discussed in the DSM stakeholder forum and considered for future DSM proposals. The DSM stakeholder group should consider if a 10% adder or some other method is appropriate when it discusses future DSM program offerings.

367. Third, the Commission directs NorthWestern to continue recovery of DSM expenses in its annual electricity supply cost tracking mechanism. Paragraph 2 of the Stipulation allows for the capitalization of NWE's DSM expenditures as a regulatory asset in the year the expenditures are incurred. NWE cites Mont. Code Ann. §§ 69-3-702, -712, and 69-3-1206 in support of its position that inclusion of DSM costs in rate base is consistent with policy expressed by the Montana Legislature that utilities should be encouraged to invest in conservation resources. NWE In. Br. at 13 (Jul. 10, 2019). NWE also cites to prior Commission orders to suggest that inclusion of DSM expenditures in rate base is consistent with Commission precedent. *Id*., *citing* Dkt. D94.11.49, Order No. 5875, 6 (Oct. 31, 1995), *and* Dkt. D2014.6.53, Order No. 7375a, ¶ 56 (Oct. 15, 2015).

368. NWEC also provided post-hearing briefing advocating approval of the DSM settlement. *See generally* NWEC Resp. Br. at 2-9 (Jul. 31, 2019). NWEC's brief focuses on a variety of policy-based reasons for capitalization of DSM expenditures. However at hearing, Rivas initially testified that, while he does not oppose capitalizing DSM costs, he prefers the current practice of expensing them. Test. Rivas at 5. Rivas noted that capitalization of DSM could be expected to increase total costs for customers; limit additional DSM investment due to lengthy spread of recovery; create a regulatory asset that provides a rate of return for dollars spent instead of savings achieved; and lead to an increased cost of debt. *Id*. at 6. However, he also noted that capitalization spreads the cost out over a period of time that matches the flow of benefits and provides incentives for utilities to more aggressively pursue DSM resources. *Id*. at 5.

369. MCC opposed the Stipulation, advocating for continued recovery of DSM expenditures as an expense. MCC contends that, because customers will pay for both the actual cost of DSM programs as well as a return on those costs (rather than the actual costs alone), capitalization will lead to increased DSM costs which, in turn will lead to increased rates. MCC Resp. Br. at 19. It suggested that NWE's proposal might violate the principal of intergenerational equity if another significant period of time elapses before NWE's next rate case. *Id*. at 21. The

MCC was also critical of the absence of a cap on deferred costs or the size of the regulatory asset. Test. Smith at 81-82.

370. Finally, MCC criticized the lack of detail in NWE's proposal in that it provided little guidance as to how the change would be implemented. Specifically, MCC pointed out that NWE did not explain how annual DSM expenses will be deferred or whether deferred investments would be amortized prior to their inclusion in rate base used for ratemaking. Test. Dismukes at 28-29.

371. LCG joined MCC in opposing the Stipulation, noting similar intergenerational inequity issues. LCG Resp. Br. at 19 (Jul. 31, 2019). LCG also argued that NWE's proposal to capitalize DSM costs is fundamentally at odds with the stated purpose of DSM programs. *Id*. To that end, LCG notes NWE's statement that "DSM 'programs promote electric energy efficiency and conservation and are *important because they reduced NWE's need to purchase or build electric supply resources*.'" *Id*., *citing* NWE In. Br. at 12 (emphasis in original). LCG points out that while DSM programs avoid the need for additions to rate base for which customers would pay NWE a return, capitalization of DSM expenditures creates the same ratemaking treatment for the DSM programs which NWE purports would reduce the need for capital investments.

372. Based on the foregoing, MCC and LCG both argue that, in contrast to recovering the actual cost of, and return on, DSM, it is more appropriate for NWE to continue dollar-for-dollar recovery of DSM costs as an expense within NWE's PCCAM.

373. The Commission agrees with the MCC position that, ultimately, capitalization of DSM expenses will lead to higher costs for ratepayers. Capitalization would mean not only a recovery of the DSM costs, but in addition, it would allow NWE a return on those costs. The Commission also agrees with the LCG and the MCC regarding intergenerational inequities if DSM costs are capitalized. As a result the Commission orders that DSM costs shall continue to be recovered on a dollar-by-dollar basis through the PCCAM.

374. The ordered treatment of DSM cost is consistent with state law. The 2019 Legislature amended Mont. Code Ann. § 69-3-712(1). That legislation, which will become effective July 1, 2020, states: "[i]n order to encourage the purchase of or investment in conservation by a utility, the commission *may* include conservation purchases or investments *and demand-side management programs* eligible under 69-3-702 and in compliance with the

criteria adopted under 69-3-711 and 69-3-1201 through 69-3-1209 in a utility's rate base." Emphasis added.

375. This amended statute explicitly includes "demand-side management programs," where the current statute does not. It also provides the Commission clear discretion in determining whether the stated expenditures should be included in rate base by replacing the word "shall" with "may". This specific exclusion of "demand-side management programs" from the current statute leads the Commission to conclude that DSM expenditures are not subject to the compulsory inclusion in rate base suggested by the current version of Mont. Code Ann. § 69-3-712. The Commission also concludes that when the newer version of § 69-3-712 becomes effective (in July of 2020), the inclusion of DSM costs in rate base will be subject to Commission discretion based on amendment of the word "shall" to "may". The Commission therefore concludes that the Commission's current practice is consistent with Montana law.

376. Importantly, the Commission observes that this issue is not properly before the Commission because NWE has not requested including any specific DSM investments in rate base. Instead NWE's request is prospective in nature because it seeks permission to account for DSM expenditures in rate base for inclusion in NorthWestern's next general rate case filing. Even if the Commission were to allow capitalized DSM costs, under the currently effective statute the Commission lacks the information necessary to perform the analysis required by §§ 69-3-712, -711, and -702 to decide whether specific DSM expenditures should be included in rate base. When NWE files it's next general rate case filing, the amended Mont. Code Ann. § 69-3-712 will be effective, and at that time, the Commission will review requests for inclusion of DSM expenditures in rate base.

C. Jurisdictional Cost of Service Study

i. *Party Positions*

377. The revenue requirement for NorthWestern's Montana retail transmission customers is presently determined, with two steps. Under its current practice, NorthWestern includes one-hundred% of its Montana transmission costs (plant and expenses) in its revenue requirement set by FERC for NorthWestern's wholesale transmission customers. Test. Cashell at 17 (Sep. 28, 2018). NorthWestern also includes that same total amount in its revenue requirement set by this Commission. *Id*. FERC allocates an appropriate portion of transmission costs to be recovered from NorthWestern's FERC-jurisdictional wholesale customers. *Id*. This

Commission then credits the total amount allocated by FERC to wholesale customers toward NorthWestern's Commission-jurisdictional retail customers. This credit operates to reduce retail customer rates. *Id*. In this way, NorthWestern ensures that one-hundred% of its transmission costs are recovered by its customers.

378. NorthWestern filed a transmission revenue requirement application with FERC on May 1, 2019. *See* FERC Dkt. Nos. ER 19-1756-000, EL18-104-000. A final order from FERC is not anticipate until mid-2020. Once FERC issues a final order in that docket, NorthWestern intends to true-up the revenue credit in this proceeding (approximately $54 million), effective upon the rate-effective date established in the FERC final order. Test. Cashell at 20. NorthWestern would apply the updated FERC rates to the transmission volumes that were the basis for the normalized revenue credits in this proceeding. *Id*. at 17, 20.

379. In this docket, NorthWestern proposes that the Commission continue this practice of calculating retail customers' share of transmission costs by reference to the allocation of transmission costs to wholesale customers made by FERC. This is the method utilized for the past ten years. Ex. NWE-16, 17; NorthWestern Op. Br. at 35; Test. Cashell at 17:4-5 *citing* Dkt. 2007.7.82, Order 6852f and Dkt. D2009.9.129, Order No. 7046h. Since both wholesale and retail customers both use the transmission system, both customer classes should pay their appropriate share of the costs. This method, NorthWestern asserts, is the most reasonable means of making that allocation because it most fairly assigns costs to the appropriate class customer while also ensuring that the utility recovers all of its costs. Test. Cashell at 18.

380. No party opposed this revenue crediting methodology. However, the MCC proposes that the Commission order that NorthWestern conduct a jurisdictional cost-of-service study allocating transmission costs among FERC-jurisdictional wholesale customers and Commission-jurisdictional retail customers, independent of the FERC methodology. Test. Dismukes, 35-36. The MCC pointed out that allocation of costs between wholesale and retail customers has been a recurring issue before the Commission, is likely to arise again, and therefore should be directly studied. MCC Resp. Br. at 25.

381. Rather than simply using FERC's determination of wholesale rates to set transmission rates for retail customers, the MCC argues that the Commission has an independent duty to determine and appropriately allocate Montana-jurisdictional transmission costs. *Id*. at 27. Thus, contrary to NorthWestern's contentions, the MCC argues that the methodology proposed

by NorthWestern makes no effort to allocate costs among cost-causers, but instead merely assigns one-hundred% of such costs to retail customers and then credits them at whatever level is approved by FERC. *Id*. at 26. As suggested by the MCC, the manner in which transmission rates are currently set by the Commission offers little in the way of assurance that those costs have been appropriately allocated by FERC. However, the MCC stops short of pointing to any specific defect in FERC's methodology.

382. The MCC also critiques NorthWestern's argument that its proposal is consistent with Commission precedent, noting that the dockets in which the practice was established were both resolved by stipulation. *Id*. at 26 *citing* Dkt. Nos. D2007.7.82 and D2009.0.129. Further, the MCC cites both such Stipulations as explicitly non-precedential. *Id*. at 26-27.

383. While NorthWestern's proposal assures complete recovery of transmission costs, the MCC acknowledges that the objective of its proposal would not be the guaranty of complete cost recovery by the utility, but rather the proper allocation of transmission costs between jurisdictions. *Id*. at 28.

384. In reply, NorthWestern points out that no party—including the MCC—has advocated for implementation of any methodology different from the status quo in this case. NorthWestern Op. Br. at 36 *citing* Hr'g Tr. 1252-21531. It also notes that Dr. David Dismukes, the MCC's own witness, did not necessarily even recommend the Commission mandate the study results be applied in future cases. *Id*. *citing* Hr'g Tr. 2180-2818.

385. NorthWestern argues that the current methodology will likely benefit retail customers in that the rate proposed in the current FERC filing is "about 55% higher" than the current rate. *Id*. at 37 *citing* Hr'g Tr. 626:13-21. Cashell testified that NorthWestern's investment in transmission has gone up substantially and that the revenue requirement will see a corresponding increase. *Id.* at 36-37. This in turn would increase the revenue requirement credit to retail customers. *Id*. *citing* Hr'g Tr. 591:20-24. NorthWestern points out that the witness for MCC conceded that, in theory, the current methodology should resolve any jurisdictional cost issues. *Id*. at 38 *citing* Hr'g Tr. 2174:7-12.

386. Finally, NorthWestern points out that there will be a cost to conducting the study proposed by the MCC, which would be properly included in customer rates. *Id*. at 36 *citing* Hr'g Tr. 2181. This, according to NorthWestern, makes the value of a jurisdictional cost-of-service

study questionable, particularly when its proponent (the MCC) has not actually advocated for implementation of study results. *Id*.

ii. ***Commission Finding***

387. The Commission first concludes that, in this docket, NorthWestern shall continue its current practice of crediting customers in its revenue requirement based on the FERC-approved allocation of transmission costs to wholesale customers.

388. Additionally, the Commission declines to adopt the MCC's request that NorthWestern be ordered to conduct a jurisdictional cost-of-service study allocating transmission costs among wholesale and retail customers, independent of the allocation conducted at FERC.

389. In deciding this issue, the Commission must balance the interests of the utility in assuring complete recovery of transmission costs, against those of retail customers within the Commission's jurisdiction in accurately determining their allocation of transmission costs. In the view of the Commission, preserving the status quo most closely assures full transmission cost recovery for NorthWestern. Barring the possibility that FERC and the Commission reach divergent conclusions as to the total amount of transmission costs properly recoverable by NorthWestern, NorthWestern is assured complete recovery of transmission-related costs if the Commission simply defers to FERC.

390. In contrast, the Commission recognizes that the proposal advanced by MCC could result in greater accuracy when determining the amount of transmission costs which are caused by customers who fall within the jurisdiction of the Commission.

391. The MCC is correct that the Commission's current methodology for allocating transmission costs to retail customers does rely in large part on FERC's allocation to wholesale customers. It is also possible that FERC's allocation could be substantially in error. However, the MCC does not point to evidence—and indeed does not appear to contend—that the methodology employed by FERC is unreasonable or contains serious flaws. As such, the Commission has little reason to believe that the results of a jurisdictional cost-of-service study would yield results substantially different from the FERC-based allocation.

392. While attractive in theory, adoption of MCC's approach may create more problems than solutions. For instance, it does not appear that MCC has expressly advocated for implementation of the results of the proposed study in this or any future Commission proceeding. The prospect of committing resources—which will ultimately be the burden of retail

ratepayers—to a cost of service study without the promise of tangible benefit is problematic, particularly when MCC has not pointed to any concrete flaw in FERC's methodology. Additionally implementation of the MCC's proposal opens the door for FERC and the Commission to reach different conclusions regarding appropriate allocation which would result in either recovery shortfall by NorthWestern (e.g. where the Commission determines that retail customers should be allocated less of NorthWestern's transmission costs than FERC); or worse, double-recovery (e.g. where the Commission determines retail customers should be allocated a greater share of transmission costs than FERC). Ultimately, the Commission believes the risk to all interested parties outweigh the benefits of ordering the cost-of-service study proposed by the MCC.

393. Having said that, the Commission acknowledges that there may be merit to the MCC's argument in the event information comes to light which suggests FERC's allocation may be flawed. To that end, the Commission encourages the MCC to pursue its proposal in future proceedings in the event it becomes aware of problems with FERC's allocation methodology.

D. Elimination of Spion Kop Annual Compliance Filing

394. NorthWestern requests the Commission to eliminate its annual compliance filing associated with the Spion Kop Wind Project. NWE App. at 6 (Sep. 28, 2019). When the Commission approved NorthWestern's acquisition of Spion Kop, it expressed concern about the risk of Spion under-performing relative to expectations and the limited site-specific wind speed data. *In re Spion Kop,* Dkt. D2011.5.41, Order 7159l ¶ 132. Accordingly, the Commission required NorthWestern to "file annual compliance filings showing Spion Kop's net capacity factor and total energy output" and required a rate adjustment if at the end of three years, Spion's average annual total energy output was less than 118,000 megawatt-hours. *Id.* NorthWestern notes that at the end of three years, Spion's average annual total energy output was 136,565 MWh. NorthWestern has submitted compliance filings showing that Spion produced 139,970 MWh, 143,192 MWh, 126,532 MWh, 130,070 MWh, and 131,819 MWh for the 12-month December through November reporting periods ending November 30 of 2013, 2014, 2015, 2016, and 2017 respectively. Spion's historical production has demonstrated that it has not under-performed expectations. NorthWestern requests that the Commission eliminate NorthWestern's obligation to make future annual compliance filings

395. NorthWestern has provided the required annual compliance filings since November 12, 2012. As no party to this docket has opposed eliminating the compliance filings, and the Commission determines NorthWestern's request is reasonable. NorthWestern's Spion Kop Annual Compliance Filing, as ordered in Commission Order No. 7159l, is eliminated.

CONCLUSIONS OF LAW

396. The Commission has jurisdiction over NorthWestern—as NorthWestern is a utility providing electric service to Montana customers—and the Commission has authority to issue a decision on NorthWestern's Application. Mont. Code Ann. §§ 69-3-101, -102, -330.

397. The Commission has provided sufficient public notice of this proceeding, and an opportunity for interested persons to be heard. Mont. Code Ann. § 69-3-104, 303(1); Title 2, Ch. 4, Pt. 6.

398. The Commission concludes that NorthWestern is providing reasonably adequate services and facilities, and that the rates and schedules approved by this Order result in just and reasonable rates. Mont. Code Ann. §§ 69-3-201; 69-3-330.

399. The Commission concludes that a customer rebate of approximately $3.74 million with interest is necessary, resulting from the difference of interim rates approved in 2019 and final rates approved by this Order. Mont. Code Ann. § 69-3-304.

400. The Commission concludes that the various customer classifications discussed in this Order are reasonable. Mont. Code Ann. § 69-3-306. The Commission concludes that net metered customer-generators should not be served under a separate service classification. Mont. Code Ann. § 69-8-611.

401. NorthWestern may not charge, demand, collect, or receive greater or less compensation for services provided than what is approved by this Order. Mont. Code Ann. § 69-3-305.

ORDER

402. NorthWestern's Application is **APPROVED** for services effective March 1, 2020. The Commission directs NorthWestern to file a compliance filing consistent with this Final Order by February 14, 2020.

403. The Commission waives the 10- and 20-day deadlines for reconsideration contemplated in Mont. Admin. R. 38.2.4806. The deadline for all reconsideration motions is

January 10, 2020. The deadline for response briefs to all reconsideration motions is **January 24, 2020.** The deadline for all reply briefs is **January 31, 2020.**

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

BRAD JOHNSON, Chairman

BOB LAKE, Vice Chairman

ROGER KOOPMAN, Commissioner

TONY O'DONNELL, Commissioner

RANDALL PINCOCCI, Commissioner

ATTEST:

Vicki LaFond-Smith
Commission Secretary

(Seal)

ADDITIONAL COMMENTS
COMMISSIONER ROGER KOOPMAN

Docket 2018.02.012

Respectfully, there are two areas of this Order where I have found myself in fundamental disagreement with my commission colleagues. To complete the historical record on this docket, a brief explanation of my contrary views and concerns is appropriate.

Regarding the proposed Fixed Cost Recovery Mechanism (commonly known as decoupling) approved by the commission on a four-year pilot basis, I would posit that commissioners simply did not give this issue serious enough thought and deliberation before the vote. With no discussion other than my own remarks, a ground-breaking decision was passed, 3 to 1.

In my judgment, the regulatory concept of decoupling is seriously flawed in at least two ways. First, it supports the public policy objective of less energy generation and less energy consumption, by compensating a utility – in this case, NorthWestern Energy – in a manner that disconnects the marketed product (electricity) from the volume of product sold. In simple, free market economic terms, rewarding a company for producing and selling less of its product is both counter-intuitive and irrational. Moreover, assigning a positive public interest to the consumption of less energy is both controversial and highly questionable. This commissioner recognizes that while energy efficiency is a cost-saving benefit to the public, and environmental stewardship is an important public objective, the net decrease in per capita energy consumption and sales is not an inherent positive. Energy usage has a direct correlation to longevity, public prosperity and the general improvement of the human condition. Decoupling creates the incentive for utilities and utilities' customers to move in the exact opposite direction. As the PSC staff memorandum acknowledged, even while generally supporting the FCRM:

> Staff agrees with HRC/NRDC that decoupling may allow NorthWestern to move beyond a business model based purely on kWh sales to one that provides services to address customer needs (services that include energy efficiency, demand response, and distributed generation.

Secondly, decoupling points future utility regulatory policy in a direction that tends to negate recent initiatives by this and other commissions to put market-based incentives in place, that reward utility monopolies for practices that mimic responses by competitive business to the dynamics of a competitive marketplace. The Montana Consumer Counsel was correct when it voiced concerns over FRCM's net effect of shifting risk from the utility to the ratepayer, not only by normalizing weather impacts, but by otherwise guaranteeing NorthWestern a certain amount of revenues in a given year, regardless of cost control breakdowns or other inefficiencies. This is accomplished through a risk-reducing decoupling surcharge that effectively blunts the impact of poor cost management and other economic factors normally borne by the utility, not the consumer.

Put simply, decoupling makes monopolies like NorthWestern Energy look more like a monopolies and less like competitive businesses. Embracing this mechanism was a major mistake on the part of the Montana commission.

One reasonable way of adjusting for some of the risk-shifting inherent in the decoupling mechanism was to acknowledge that the reduced utility risk would inevitably result in a reduced cost of debt. A logical way of addressing this would be through a modest adjustment to NWE's ROE, to be reviewed and adjusted annually. The MCC proposed a 25 basis point reduction. This commissioner lowered that to a 15 basis point adjustment, but could get no support for this consumer protection amendment from any participating commissioner.

The other disappointing commission decision involved how to address the many questions and concerns being voiced by Montana citizens over Colstrip Unit 4. NorthWestern's purchase of 30 percent of CU4, approved by the commission is 2008 was, in hindsight, one of the worst, most anti-ratepayer actions ever conceived by the PSC – resulting in an inflated cost of debt, and inflated rate of return, and a fixed rate base roughly two-and-one-half times what NW actually paid for their interest in the plant. Attitudes and opinions about coal-fired generation aside, there are major questions looming in the plant's future – along with the likely astronomical costs of decommissioning and environmental remediation when the facility closes in approximately seven years, and the generational inequities attached to ratepayers footing the bill for an asset that doesn't fully depreciate until 2043, yet likely quits providing them any energy in 2027.

It was proposed that the commission begin studying these issues in an official way, through an investigative docket that engaged in intensive research, reporting requirements and a robust process of public input. The argument was made that such action was premature, given the insufficiency of hard facts on the record regarding actual retirement dates, remediation costs, financing mechanisms and other factors.

Common sense dictates that where there is a deficiency of information, a process should commence to secure that information. It's fairly obvious that the commission will not be in a position to take action on any of these CU4-related issues any time soon. But I fail to see the benefit of putting off the fact-finding process, and thus further delaying the commission's ability to address these important issues in an informed manner. Unfortunately, I was the lone commissioner who wanted to proceed with an investigative docket. I truly believe we will come to regret that hasty and short-sighted decision.

Roger Koopman
Commissioner

APPENDIX

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

IN THE MATTER OF NorthWestern Energy's Application for Authority to Increase its Retail Electric Utility Service Rates and For Approval Of its];'.lectric Service Schedules and Rules.	))))	REGULATORY DIVISION DOCKET NO. D2018.2.12

AMENDED STIPULATION AND SETTLEMENT AGREEMENT OF !NORTHWESTERN ENERGY, THE MONTANA CONSUMER COUNSEL, THE MONTANA LARGE CUSTOMER GROUP, THE FEDERAL EXECUTIVE AGENCIES, AND WALMART

NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern"), the Montana Consumer Counsel ("MCC"), the Montana Large Customer Group ("LCG"), the Federal Executive Agencies ("FEA"), and Walmart (collectively "Stipulating Parties"), by and through their undersigned representatives, hereby submit to the Montana Public Service Commission ("Commission") this Amended Stipulation and Settlement Agreement ("Amended Stipulation"). For settlement purposes, a fair and equitable resolution of this Docket has been reached on the revenue requirement; revenue allocation; rate design for the GS-1 Secondary demand non-choice class, the GS-I Primary classes, and GS-2 Substation and Transmission classes; and other related issues between the Stipulating Parties ("Settled Issues"). To establish just and reasonable rates for NorthWestern's customers and reach a fair and equitable resolution of the issues that were raised or could have been raised by the Stipulating Parties- regarding the Settled Issues the Stipulating Parties stipulate and agree as follows:

1. For services rendered on or after the date the Commission approves compliance rates pursuant to its Final Order in this docket, NorthWestern shall be authorized to collect an overall revenue increase of$6.5 million for electric service, subject to any ROE adjustment ordered under paragraph 6 below, consisting of a decrease in generation revenues of $11,914,385 and an increase in transmission and distribution revenues of $18,414,385.

2. The overall revenue increase of $6.5 million for electric service shall be allocated to NorthWestern's customer classes as shown on Exhibit A to this Amended Stipulation in the sections labeled Settlement Revenue Allocation and Settlement Class Revenue Allocation on pp. 1-2 of the exhibit. The functional revenue changes shall be as shown on Exhibit A to this Amended Stipulation in the section labeled Functional Revenue Changes on p. 3 of the exhibit. For the General Service **1** Secondary Demand Non-Choice rate class, the General Service 1 Primary Demand and Non-Demand and Choice and Non-Choice rate classes, the General Service 2 Substation Choice and Non-Choice rate classes, and General Service 2 Transmission Choice and Non-Choice rate classes the rates shall be as shown in &hibit A to this Amended Stipulation in the section labeled Rate Summary Proposed Rates on pp. 4-7 of the exhibit. For all other rate classes, the rates shown in Exhibit A on

the section labeled Rate Swnmary Proposed Rates are illustrative as the rate design for those rates is not being settled in this Amended Stipulation. NorthWestern is not precluded from adjusting the rate components between the "Base w/o Tax" and "Property Tax Charge" in Exhibit A on a revenue neutral basis for any subclass, as may be necessary to recover the target property tax revenue requirement.

3. Except as provided in paragraph 13, the baseline electricity supply costs and credits for NorthWestern's Power Costs and Credits Adjustment Mechanism shall be as proposed in Kevin J. Markovich's rebuttal testimony.

4. The settlement rate increase is incremental to $7,463,894 of property tax revenue reflected in rates effective January I, 2019, pursuant to Docket No. D2018.11.80. Therefore, the rates shown in Exhibit A to the Amended Stipulation do not reflect those changes to rates. If the Commission approves this Amended Stipulation, the resulting electric customer rates would be the rates shown in Exhibit A to the Amended Stipulation, adjusted for any changes to final rate design approved by the Commission, plus the rate increases approved in Docket No. D2018.l 1.80 to reflect 2019 estimated property taxes. For purposes of future property tax tracker filings, the base level of property taxes from this rate case shall be the actual level of property taxes in 2018.

5. Solely for purposes of this Amended Stipulation, the authorized revenue increase is based on an authorized rate of return on equity (ROE) of 9.65%, with the exception of Colstrip Unit 4's ROE at 10.0%, the capital structure as proposed by NorthWestern, and a compromise regarding the other cost of service items.

6. If a Fixed Cost Recovery Mechanism pilot is approved, the ROE would be subject to potential downward adjustment of up to 25 basis points.

7. NorthWestern's proposed depreciation rates, as presented in the testimony of Crystal D. Lail, shall be adjusted to include the extended depreciable lives for NorthWestern's Montana transmission and distribution assets (as proposed by the MCC) and the Dave Gates Generating Station (as proposed by the LCG and FEA), as detailed in Exhibit B.

8. NorthWestern agrees that any future adjustment ofNorthWestem's depreciation rates shall require Commission approval.

9. The Stipulating Parties accept NorthWestern's amount of Excess Accumulated Deferred Income Taxes and amortization as proposed in Aaron J. Bjorkman's rebuttal testimony.

10. The Stipulating Parties accept the functionalization of the Regulatory Plant Adjustment as proposed by LCG and FEA.

11. With the exception of the functionalization of the Regulatory Plant Adjustment, the Stipulating Parties accept the Colstrip Unit 4 revenue requirement as proposed by NorthWestern.

12. The Amended Stipulation resolves all issues raised by the Stipulating Parties regarding revenue requirements, and cost allocation.

13. The Amended Stipulation does not resolve any issues related to rate design, except as described in paragraph 2 above; decoupling, except as described in paragraph 6 above; net metering; FEA's proposal concerning their allocation ofhydropower from the Western Area Power Administration; the handling of future transmission credits through the PCCAM, the allocation of wholesale service credits, and the possibility of requiring further study of these issues; and any other issue not specifically addressed in the Amended Stipulation.

14. Except as specifically noted below, no individual Stipulating Party's position in this docket is accepted by any other Stipulating Party by virtue of its entry into this Amended Stipulation, nor does it indicate any Stipulating Party's acceptance, agreement, or concession to any rate making principle, cost of service determination, or legal principle embodied or arguably embodied in this Amended Stipulation. While the Stipulating Parties have not agreed on a specific derivation of the stipulated revenue increase, the Stipulating Parties agree that the Amended Stipulation as a whole provides NorthWestern a reasonable opportunity to recover its prudently incurred costs based on the evidence in this docket.

15. The Stipulating Parties stipulate to the admission into the evidentiary record of all pre-filed testimony and exhibits of the witnesses for the Stipulating Parties to support the reasonableness of the Amended Stipulation and shall refrain from cross-examining the witnesses of the other Stipulating Parties regarding the issues other than the Settled Issues. The Stipulating Parties shall each call one or more witnesses at hearing to support this Amended Stipulation.

16. The various provisions of this Amended Stipulation are inseparable from the whole of the agreement between the Stipulating Parties. The reasonableness of the proposed settlement set forth in this Amended Stipulation is dependent upon its adoption, in its entirety, by the Commission. If the Commission decides not to adopt the proposed settlement set forth in this Amended Stipulation in its entirety, then the entire Amended Stipulation is null and void, no party to the Amended Stipulation is bound by any provision of it, and it shall have no force or effect whatsoever.

17. The Stipulating Parties acknowledge that this Amended Stipulation is the result of a voluntary, negotiated settlement between them pursuant to ARM 38.2.3001, and agree that this Amended Stipulation, inclusive of the compromises and settlements contained herein, is in the public interest.

18. This Amended Stipulation may be executed in one or more counterparts and each counterpart shall have the same force and effect as an original document, fully executed by the Stipulating Parties. Any signature page of this Amended Stipulation may be detached from any counterpart of this Amended Stipulation without impairing the legal effect of any

signatures thereon, and may be attached to another counterpart of this Amended Stipulation identical in form hereto but having attached to it one or more signatures page(s).

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Settlement Revenue Allocation

(Al)	(B)	(C)	(D)	(E)	(F)	(GJ)	(HJ)
	Revenues	Allocated	At Egualiz ed ROR		Revenue Allocation. $6.SM Increase		
Linc No. Customer Class	at Current Rates	Costs of Service	Incr./(Decr.) $	Incr./-Decr. %	Rate Revenue	Incr./(Decr.) $	Iner.I-Deer. %
I Residential Cho ice & Non-Choice	$223,205.546	$242.461,965	$ 19,256,420	8.63%	$226,950,292	$3,744,746	1.68%
2 Residential E mployee	$148,256	$300.387	$ 152, 130	102.6 1%	150,734	$2,477	1.67%
3 Residential Net Metering	$1,074,634	$1,660.138	$585 ,504	54.48%	1,098 ,170	$23,536	2.19%
4 **Residential**	$224.428.436	$244,422,490	$19,99, 4 053	8.91%	$228 ,199, 195	$3,770,759	1.68%
5 OS I Sec Non Dmd	$29,257,033	$27,384,884	($1,872,149)	-6.40%	$29,246. I63	($10,87 1)	-0 .04%
6 OSI Sec Non Dmd Choice	$ 4, 2 907	$44 ,266	$1,359	3.17%	$43 ,828	$92 1	2.15%
7 GSI Sec Non Dmd Net Meter	$160,029	$126,484	($33,545)	-20.96%	$ 158,688	($ I,34 I)	-0.84%
8 OSI Sec Dmd Non Choice	$194, 46,0 516	$186 ,071 ,298	($8,389,2 I8)	-4.31%	$198,627,927	$4,167,411	2.14%
9 GSI Sec Dmd Choice	$1,440,596	$1,605,482	$164,886	11.45%	$1,656,414	$215,818	14.98%
10 GSI Sec Dmd Net Meter	$2,881,740	$2,678,206	($203,533)	-7.06%	$2,960,535	$78,796	2.73%
11 **General_Service 1 Secondar_y**	$228,242,821	$217,910,620	($ I 0,33 2.20 I)	-4.53%	$232,69, 3 556	$4,45, 0 735	1.95%
12 GSI Pri Non Dmd Non-Choice & Choice	$4, 5 982	$48,110	$2,128	4.63%	$44,946	($, 1 036)	-2.25%
13 OSI Pri Dmd Non Choice	$2, 3 250,006	$20,966,699	($2,283,308)	-9.82%	$22,543,358	($706,649)	-3.04%
14 OSI Pri Dmd Choice	$1, 132,231	$503 ,217	($629,014)	-55.56%	$1,303.579	$171 348	15.13%
15 GS! Pri Dmd Net Metering	$137,643	$143,563	$5,920	4.30%	$13, 3 530	($,4 113)	-2.99%
16 **Ge nera l Service 1 Primary**	$24,565,861	$21,66 I.588	($2.904,273)	-11.82%	$24,025,413	($54,0 449)	-2 .20%
17 GS2 Sub Non Choice	$14,145,374	$ I, 1 856,789	($2.288.585)	-16.18%	$ 12,650 ,933	($ 1,494 ,441)	- 10.56%
18 GS2 Sub Choice	$5,109,040	$4 934,558	($174,482)	-3.42%	$5,236 ,417	$127,377	2.49%
19 **General Se rvice 2 Substation**	$19,254,414	$16 ,791,348	($2.463,067)	-12.79%	$17,88,7 35 1	($ 1,36,7 063)	-7. 10%
20 GS2 Tran Non Choice	$6,128,021	$5,548,618	($579,403)	-9.45%	$5.800.048	($327,973)	-5.35%
21 GS2 Tran Choice	$1 153,796	$37,684	($1 116, 111)	-96.73%	$1,039 763	($114 033)	-9.88%
22 **General Service 2 Transm**	$7,281,817	$5,586,303	($1,695,514)	-23.28%	$6,83, 9 811	($442,006)	-6.07%
23 Irrigation Non Dmd	$466,527	$741,128	$274,601	58.86%	$489,859	$23,332	5.00%
24 Irrigation Non Dmd Net Metering	$1,627	$2.433	$806	49.52%	$1,703	$76	4.65%
25 Irrigat ion Dmd	$8,441,167	$11,926,156	$3,484,988	41.29%	$8.863 265	$422,097	5.00%
26 Irriga tion Dmd Net Metering	$14,623	$25,948	$11,325	77.45%	$15,3 15	$692	4.73%
27 **Irrigation**	$8,923,944	$ I2,695,665	$3,771,721	42.27%	$9,370,142	$446,197	5.00%
28 Light Non-Choice Company Own	$12,627,143	$12,282,395	($344 ,748)	-2.73%	$12.778,857	$151.713	1.20%
29 Lighting Choice Company Own	$1,008,816	$1,468,656	$459,840	45.58%	$1 029 776	$20,960	208%
30 Light Non-Choice Cust Own	$857,006	$823,560	($33,446)	-3.90%	$8,64003	$6,998	0.82%
31 Light Choice Cust Own	$26,476	$22,771	($3,705)	-13.99%	$27 152	$677	2.56%
32 Light Metered Non-Choice Cust Own	$260,766	$309,740	$48,974	18.78%	$262,160	$1,394	0.53%
33 Light Me tere d Choice Cust Own	$2,519	$4,884	$2,365	93.88%	$2,605	$86	3.40%
34 **Lighting**	$14,782,726	$14.912,007	$129,281	0.87%	$14,964,554	$181.828	1.23%
35 **Total**	$527,480,020	$53, 3 980,020	$, 6 500,000	1.23%	$533 ,98, 0 020	$6,500.000	1.23%

Settlement Class Revenue Allocation

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Revenues at Current	Allocated Costs of	At Egualized ROR		$6.5M Increruie		
Customer Class	Rate11	Service	InerJ ecr.·! $	Iner.I-Deer. %	Rate Revenue	InerJ@ecr.} $	IncrJ-Decr.%
Residential	$224,428,436	$244,422,490	$19,994,053	8_91%	$228,199,195	$3,770,759	1.68%
General Service 1 Secondary	$228,242,821	$217,910,620	-$10,332,201	-4.53%	$232,693,556	$4,450,735	1.95%
General Service 1 Primary	$24,565,861	$21,661,588	-$2,904,273	-11.82%	$24,025,413	-$540,449	-2.20%
General Service 2 Substation	$19,254,414	$16,791,348	-$2,463,067	-12.79%	$17,887,351	-$1,367,063	-7.10%
General Service 2 Transm	$7,281,817	$5,586,303	-$1,695,514	-23.28%	$6,839,811	-$442,006	-6.07%
Irrigation	$8,923,944	$12,695,665	$3,771,721	42.27%	$9,370,142	$446,197	5.00%
Lighting	$14,782,726	$14,912,007	$129,281	0.87%	$14,964,554	$18L828	1.23%
Tomi	$527,480,020	$533,980,020	$6,500,000	1.23%	$533,980,020	$6,500,000	1.23%

Functional Revenue Changes

Descrietion	Current T&D Revenues	Current Gen. Revenun	Cnrtent Total	Proposed T&D Revenues	Proposed Gen. Revenues	Proposed T,W	Inc./(Dec.) T&DRevenua	Iuc.l{Dec.) Gen..Reveuues	IncJ(Dec.) Total
Res Non Choice	$111,414,655	$103,101,013	$214,515,668	$121,235,879	$96,881,189	$218,117,068	$9,821,224	-$6,219,824	$3,601,400
1,'rup Non Choice	$76,323	$70,633	$146,956	$83,048	$66,373	$149,421	$6,725	-$4,260	$2,465
Res Choice	'416	$0	$416	'476	$0	$476	$60	$0	$60
Low Inc Non Choice	$4,509,537	$4,179,925	$8,689,462	$4,904,987	$3,927,761	$8,832,748	$395.450	-$252,164	$)43,286
Res Net Metering	$546,807	$491,977	$1,038,784	$599,218	$462,298	$1,061,516	$52,411	-$29,680	$22,731
Emp Net Metering	$662	$638	$I.JOO	$713	$599	$1,313	$51	-$38	$12
LowIncNet Metering	$18,899	$16,951	$35,849	$20,726	$15,928	$36,654	$1 827	-$1,023	$805
Total Residential	$116,567,300	$107,861,137	$224,428,436	$126,845,048	$101,354,147	$228,199,195	$10,277,749	-$6,506,990	$3,770,759
('n,neraJ Service 1 Second!!!!									
GSl Sec Non Dmd Non Choice	$17,151,542	$12,105,492	$29,257,033	$17,504,941	$11,741,222	$29,246,163	$353,399	-$364,270	-$10,871
GSl Sec Non Dmd Choice	$42,907	$0	$42,907	$43,828	SO	$43,828	$921	$0	$921
GSl Sec Non Dmd Net Meter	$91,001	$69,028	$160,029	$91,738	$66,951	$158,688	$736	-$2,077	-$1,341
GSI SecDmdNon Choice	$88,088,845	$106,371,671	$194,460,516	$95,457,116	$103,170,811	$198,627,927	$7,368,271	-$3,200,861	$4,167,411
GS1 Sec Dmd Choice	$1,440,596	$0	$1,440,596	$1,656,414	$0	$1,656,414	$215,818	$0	$215,818
GSl SecDmdNetMetcr	$1,360,650	$1,498,777	$2,859,427	$1,480,995	$1,453,677	$2,934,672	$120,345	,$45,100	$75,245
GSI Sec Dmd Choice Net Meter	$22,313	$0	$22,313	$25,864	$0	$25,864	$3,551	$0	$3,551
Total General Service 1 Secondary	$108,197,853	$120,044,967	S228,242,821	$116,260,896	$116.432,660	$232,693,556	$8,063,043	-$3,612,308	$4,450,735
Gen!;lr!l Serviu 1 PrimID									
GS!Pri Non Dmd Non Choice	$20.807	$24,494	$45,301	$21,530	$22,716	*$44,246*	$723	-$1,778	-$1,055
GSl Pri Non Drud Choice	$681	$0	$681	$700	$0	$700	$20	$0	$20
GSl PriDmdNon Choice	$8,981,002	$14,269,004	$23,250,006	$9,310,284	$13,233,074	$22,543,358	$329,282	-$1,035,930	-$706,649
GSI Pri Dmd Choice	$1,132,231	$0	$1,132,231	$1,303,579	$0	$1,303,579	$171,348	$0	$J71,348
GSI Pri Dmd Net Metering	$5}.931	$85,712	$137,643	$54,041	$79,489	$133,530	$2,110	-$6.223	--$4,113
Total General Service l Primary	$10,186,652	$14,379,210	$24,565,861	$10,690,134	$13,335,279	$24,025,413	$503,482	-$1,043,931	-$540,449
neral Service l Substation									
GS2 SubN011 Choice	$3,791,837	$10,353,537	$14,145,374	$2,783,746	$9,867,187	$12,650,933	-$1,008,091	-$486,350	-$1,494,441
GS2 Sub Choice	$5,109,040	$0	$5,109,040	$5,236,417	$0	$5,236,417	$127,377	$0	$127,377
Total General Service 2 Substation	$8,900,877	$10,353,537	$19,254,414	$8,020,164	$9,867,187	$17,887,351	-$880,714	-$486,350	-$1,367,063
Y!ntr11I :Stnitt 2Tr1n1m									
GS2 Tran Non Choice	$1,441,416	$4,686,605	$6,128,021	$1,456,046	$4,344,002	$5,800,048	$14,629	·$342,603	·$327,973
GS2 Tran Choice	$1,153,796	$0	$1,153,796	$1,039,763	$0	$1,039 763	-$114,033	$0	-$114,033
Total General Service 2 Transm	$2,595,212	$4,686,605	$7,281,817	$2,495,808	$4,344,002	$6,839,811	-$99,404	-$342,603	-$442,006
Irrigation									
hrigatio11 Non Dmd Non Choice	$252,565	$213,962	$466,527	$264,519	$225,340	$489,859	$11,954	$11,378	$23,332
Irrigation Non Dmd Choice		$0	!O	$0	$0	$0	$0	$0	$0
hrigation Non Dmd Net 1ietering	$828	$799	$1,627	$86)	$842	$1,703	$33	$43	$76
Irrigation Dmd Noll Choice	$4,427,793	$4,005-:iz5	$8,433,117	$4,636,274	$4,218,316	$8,854,590	$208,481	$212,991	$421,472
Irrigation Dmd Choice	$8,050	$0	$8,050	$8,675	$0	$8,675	$625	SO	$625
Irrigation Dmd Net Metering	$6,722	$7,901	$14,623	$6,994	$8,321	$15,315	$272	'420	*$692*
Total Irrigation	$4,695,957	$4,227,987	$8,923,944	$4,917,323	$4,452,819	$9,370,142	$221,365	$224,832	$446,197
Total Excluding Lighting	$251,143,851	$261,553,443	$512,697,294	$269,229,373	$249,786,094	$519,015,467	$18,085,521	·$11,767,349	$6,318,172
Total Company Owned Lighting	$11,838,550	$1,797,410	$13,635,960	$12,121,558	$1,687,075	$13,808,633	$283,008	-$110,335	$172,673
Customer Owned Lighting	$548,891	$597,876	$1,146,767	$594,746	$561,175	$1.155,921	$45,855	-$36,701	$9,154
Total All Rates	$263,531,292	$263,948,729	$527,480,020	$281,945,676	$252,034,344	$533,980,020	$18,414,3!!5	-$11,914,385	$6,500,000

NorthWestern Energy
Electric Utility Rate Design
Rate Summary Proposed Rates

Line No.	(A) Descrletlon	(B) Annual Customers	(C) KWH Sales	(0) KW Demands	(E) Delivery Service Charge	(F) !;aenmtiQn Ch1.ra1 Base w/oTax	(G) Property Tax Charge	(H) Two Dot Charge Base w/oTax	(I) Property Tax Charge
1	Residential								
2	Res Non Choice	3,383,147	2,361,777,001		$5.60	$0.036058	$0.004491	$0.000447	$0.000024
3	Emp Non Choice	3,860	2,696,737		$3.36	$0.021635	$0.002694	$0.000268	$0.000015
4	Res Choice	32	9,000		$5.60	$0.000000	$0.000000	$0.000000	$0.000000
5	Low Inc Non Choice	135,345	95,751,247		$5.60	$0.036058	$0.004491	$0.000447	$0.000024
6	Res Net Metering	19,841	11,269,924		$5.60	$0.036058	$0.004491	$0.000447	$0.000024
7	Emp Net Metering	24	24,348		$3.36	$0.021635	$0.002694	$0.000268	$0.000015
8	Low Inc Net Metering	698	388,296		$5.60	$0.036058	$0.004491	$0.000447	$0.000024
9	Total Resldential	3,542,947	2,471,916,552						
10									
11	eneral §ervlce 1 §econdart								
12	GS1Sec Non Dmd Non Choice	549,336	277,305,440		$6.95	$0.037363	$0.004539	$0.000415	$0.000024
13	GS1 Sec Non Dmd Choice	1,884	761,314		$6.95	$0.000000	$0.000000	$0.000000	$0.000000
14	GS1 Sec Non Dmd Net Meter	1,970	1,581,248		$6.95	$0.037363	$0.004539	$0.000415	$0.000024
15	GS1 Sec Dmd Non Choice	243,624	2,436,699,299	7,527,644	$8.70	$0.037363	$0.004539	$0.000415	$0.000024
16	GS1 Sec Dmd Choice	1,481	64,032,677	166,466	$8.70	$0.000000	$0.000000	$0.000000	$0.000000
17	GS1 Sec Dmd Net Meter	2,396	34,333,089	119,127	$8.70	$0.037363	$0.004539	$0.000415	$0.000024
18	GS1 Sec Dmd Choice Net Meter	24	918,160	2,638	$8.70	$0.000000	$0.000000	$0.000000	$0.000000
19	Total General Service 1 Secondary	800,715	2,815,631,227	7,815,875					
20									
21	§eneral §ervlce 1 Prfmart								
22	GS1 Pri Non Dmd Non Choice	513	576,882		$8.80	$0.034523	$0.004429	$0.000401	$0.000024
23	GS1 Pri Non Dmd Choice	12	27,883		$8.80	$0.000000	$0.000000	$0.000000	$0.000000
24	GS1 Pri Dmd Non Choice	1,486	336,065,473	787,267	$27.70	$0.034523	$0.004429	$0.000401	$0.000024
25	GS1 Pri Dmd Choice	48	72,879.078	136,690	$27.70	$0.000000	$0.000000	$0.000000	$0.000000
26	GS1 Pri Dmd Net Metering	23	2,018,700	4.448	$27.70	$0.034523	$0.004429	$0.000401	$0.000024
27	Total General Service 1 Primary	2,082	411,568,015	928,404					
28									
29	General Service 2 Substation								
30	GS2Sub Non Choice	235	245,968,136	670,947	$225.00	$0.035326	$0.004376	$0.000390	$0.000024
31	GS2 Sub Choice	384	1,882,910,157	3,179,317	$225.00	$0.000000	$0.000000	$0.000000	$0.000000
32	Total General Service 2 Substation	619	2,128,878,293	3,850,265					
33									
34	•aeral §ervlce 2 Transm								
35	GS2 Tran Non Choice	228	112,015,223	356,693	$1,380.00	$0.034028	$0.004334	$0.000395	$0.000023
36	GS2 Tran Choice	60	547,649,462	947,788	$1,380.00	$0.000000	$0.000000	$0.000000	$0.000000
37	Total General Service 2 Transm	288	659,664,685	1,304,481					
38									
39	Irrigation								
40	Irrigation Non Dmd Non Choice	1,256	4,901,322		$47.35	$0.041027	$0.004616	$0.000317	$0.000016
41	Irrigation Non Dmd Choice	0	0		$47.35	$0.000000	$0.000000	$0.000000	$0.000000
42	Irrigation Non Dmd Net Metering	2	18,314		$47.35	$0.041027	$0.004616	$0.000317	$0.000016
43	Irrigation Dmd Non Choice	2,648	91,751,604	380,305	$111.60	$0.041027	$0.004616	$0.000317	$0.000016
44	Irrigation Dmd Choice	2	150,066	930	$111.60	$0.000000	$0.000000	$0.000000	$0.000000
45	Irrigation Dmd Net Metering	1	180,989	587	$111.60	$0.041027	$0.004616	$0.000317	$0.000016
46	Total Irrigation	3,909	97,002,296	381,822					
47									
48	Total Excluding Lighting	4,350,560	8,584,661,069	14,280,647					
49		Units							
50	Total Company Owned Lighting	905,597	44,729,819						
51	Customer O'M'led Lighting	136,533	14,511,034						
52	Total All Rates		8,643,901,922	14,280,847					

Line No.	Descrietion	Transmission Enera Base w/o Tax	Transmission Enera Property Tax Char9e	Transmission Demand Base w/o Tax	Transmission Demand Property Tax Char9e	Distribution Ener!n". Base w/o Tax	Distribution Ener!n". Property Tax Char9e	Distribution Demand Base w/o Tax	Distribution Demand Property Tax Char!!e	
	(A)	(J)	(K)	(L)	(M}	(N)	(0)	(P)	(Q)	(R)
1	**Residential**									
2	Res Non Choice	$0.004027	$0.006284			$0.020660	$0.012339			
3	Emp Non Choice	$0.002416	$0.003771			$0.012396	$0.007403			
4	Res Choice	$0.000000	$0.000000			$0.020660	$0.012339			
5	Low Inc Non Choice	$0.004027	$0.006284			$0.020660	$0.012339			
6	Res Net Metering	$0.004027	$0.006284			$0.020660	$0.012339			
7	Emp Net Metering	$0.002416	$0.003771			$0.012396	$0.007403			
8	Low Inc Net Metering	$0.004027	$0.006284			$0.020660	$0.012339			
9	Total Residential									
10										
11	General Service 1 Secondatv									
12	GS1 SecNon DmdNon Choice	$0.003203	$0.005784			$0.027580	$0.012790			
13	GS1 Sec Non Dmd Choice	$0.000000	$0.000000			$0.027580	$0.012790			
14	GS1 Sec Non Dmd Net Meter	$0.003203	$0.005784			$0.027580	$0.012790			
15	GS1 Sec Dmd Non Choice			$1.033301	$1.737241	$0.002936	$0.001072	$6.103848	$2.227689	
16	GS1 Sec Dmd Choice			$0.000000	$0.000000	$0.002936	$0.001072	$6.103848	$2.227689	
17	GS1 Sec Dmd Net Meter			$1.033301	$1.737241	$0.002936	$0.001072	$6.103848	$2.227689	
18	GS1 Sec Dmd Choice Net Meter			$0.000000	$0.000000	$0.002936	$0.001072	$6.103848	$2.227689	
19	Total General Service 1 Secondary									
20										
21	**General Service 1 Prima01**									
22	GS1 Pri Non Dmd Non Choice	$0.003331	$0,004840			$0.014697	$0.006628			
23	GS1 Pri Non Dm d Choice	$0.000000	$0.000000			$0.014697	$0.006628			
24	GS1 Pri Dmd Non Choice			$1.190127	$1.973918	$0.006669	$0.001961	$3.806742	$1.119242	
25	GS1 Pri Dmd Choice			$0.000000	$0.000000	$0.006669	$0.001961	$3.806742	$1.119242	
26	GS1 Pri Dmd Net Metering			$1.190127	$1.973918	$0.006669	$0.001961	$3.806742	$1.119242	
27	Total General Service 1 Primary									
28										
29	**General Service 2 Substation**									
30	GS2 Sub Non Choice			$0.913254	$1.537069			$1.066720	$0.553130	
31	GS2 Sub Choice			($0.000000)	$0.000000			$1.066720	$0.553130	
32	Total General Service 2 Substation									
33										
34	**General Service 2 Transm**									
35	GS2 Tran Non Choice			$0.849659	$1.340627			$0.881979	$0. 127701	
36	GS2 Tran Choice			($0.000000)	$0.000000			$0.881979	$0.127701	
37	Total General Service 2 Transm									
38										
39	**Irrigation**									
40	Irrigation Non Dmd Non Choice	$0.004217	$0.004175			$0.008537	$0.024907			
41	Irrigation Non Dmd Choice	$0.000000	$0.000000			$0.008537	$0.024907			
42	Irrigation Non Dmd Net Metering	$0.004217	$0.004175			$0.008537	$0.024907			
43	Irrigation Dmd Non Choice			$0.946064	$1.013810	$0.002106	$0.002423	$3.887916	$4.473397	
44	Irrigation Dmd Choice			$0.000000	$0.000000	$0.002106	$0.002423	$3.887916	$4.473397	
45	Irrigation Dmd Net Metering			$0.946064	$1.013810	$0.002106	$0.002423	$3.887916	$4.473397	
46	Total Irrigation									
47										
48	Total Excluding Lighting									
49										
50	Total Company Owned Lighting									
51	Customer Owned Lighting									
52	Total All Rates									

	{A}	{S}	{T}	{U}	M	{W}
		Delivery	GtntritiQn Rtv§:nyg		Two Dol Rgvgnyu	
Line		Service	Base	Property	Base	Property
No.	Descrletlon	Revenues	w/o Tax	Tax Rev	w/oTax	Tax Rev
1	Resldentlal					
2	Res Non Choice	$18,945,623	$85,161,542	$10,605,859	$1,056,520	$57,268
3	Emp Non Choice	$12,970	$58,344	$7,266	$724	$39
4	Res Choice	$179	$0	$0	$0	$0
5	Low Inc Non Choice	$757,932	$3,452,622	$429,983	$42,833	$2,322
6	Res Net Metering	$111,110	$406,374	$50,609	$5,041	$273
7	Emp Net Metering	$81	$527	$66	$7	$0
8	Low IncNet Metering	$3,909	$14,001	$1,744	$174	$9
9	Total Residential	$19,831,803	$89,093,410	$11,095,527	$1,105,299	$59,912
10						
11	Qeneral §ervlce 1 §econda!I'.					
12	GS1 Sec Non Dmd Non Choice	$3,817,885	$10,360,879	$1,258,577	$115,149	$6,617
13	GS1 Sec Non Dmd Choice	$13,094	$0	$0	$0	$0
14	GS1 Sec Non Dmd Net Meter	$13,692	$59,080	$7,177	$657	**$38**
15	GS1 Sec Dmd Non Choice	$2,119,529	$91,041,656	$11,059,188	$1,011,825	$58,141
16	GS1 Sec Dmd Choice	$12,885	$0	$0	$0	$0
17	GS1 Sec Dmd Net Meter	$20,845	$1,282,777	$155,824	$14,257	$819
18	GS1 Sec Dmd Choice Net Meter	$209	$0	$0	$0	$0
19	Total General Service 1 Secondary	$5,998,138	$102,744,391	$12,480,766	$1,141,888	$65,615
20						
21	general iervlce 1 Prfmani::					
22	GS1 Pri Non Dmd Non Choice	$4,514	$19,916	$2,555	$231	$14
23	GS1 Pri Non Dmd Choice	$106	$0	$0	$0	$0
24	GS1 Pri Dmd Non Choice	$41,162	$11,602,042	$1,488,276	$134,843	$7,912
25	GS1 Pri Dmd Choice	$1,330	$0	$0	$0	$0
26	GS1 Prl Dmd Net Metering	$637	$69,692	$8940	$810	**$48**
27	Total General Service 1 Primary	$47,749	$11,691,650	$1,499,771	$135,885	$7,973
28						
29	General Service 2 Substation					
30	GS2 SubNon Choice	$52,875	$8,689,014	$1,076,345	$96,039	$5,788
31	GS2 Sub Choice	$86,400	$0	$0	$0	$0
32	Total General Service 2 Substation	$139,275	$8,689,014	$1,076,345	$96,039	$5,788
33						
34	general iervlce 2 Transm					
35	GS2 Tran Non Choice	$314,640	$3,811,683	$485,515	$44,225	$2,579
36	GS2 Tran Choice	$82,800	$0	$0	$0	$0
37	Total General Service 2 Transm	$397,440	$3,811,683	$485,515	$44,225	$2,579
38						
39	Irrigation					
40	Irrigation Non Dmd Non Choice	$59,472	$201,086	$22,623	$1,555	$76
41	Irrigation Non Dmd Choice	$0	$0	$0	$0	$0
42	Irrigation Non Dmd Net Metering	$95	$751	$85	$6	$0
43	Irrigation Dmd Non Choice	$295,517	$3,764,281	$423,503	$29,100	$1,432
44	Irrigation Dmd Choice	$223	$0	$0	$0	$0
45	Irrigation Dmd Net Metering	$112	$7,425	$835	$57	**$3**
46	Total Irrigation	$355,418	$3,973,544	$447,046	$30,718	$1,511
47						
48	Total Excluding Lighting	$26,769,823	$220,003,692	$27,084,969	$2,554,054	$143,379
49		Ownershle				
50	Total Company Owned Lighting	$10,396,448	$1,484,179	$183,569	$18,282	$1,045
51	Customer Owned Lighting	$33,128	$493,685	$61,061	$6,081	$347
52	Total All Rates	$37,199,399	$221,981,557	$27,329,599	$2,578,417	$144,771

Line No.	{A) Descrletlon	{X) Transm Ene!!l:t: Rev Base w/oTax	M Transm Ene!!l:t: Rev Property Tax Rev	IZ) Transm Demand Rev Base wloTax	{AA) Transm Demand Rev Property Tax Rev	{AB) Dlstr En•!!l:t Rev Base w/oTax	{AC) Dlstr En•!!l:t Rev Property Tax Rev	{AD) Dlstr Demand Rev Base w/o Tax	{AE) Dlstr Demand Rev Property Tax Rev	{AF) Total Revenue
1	Resldentlal									
2	Res Non Choice	$9,511,587	$14,842,457			$48,793,961	$29,142,250			$218,117,068
3	Emp Non Choice	$6,516	$10,168			$33,429	$19,965			$149,421
4	Res Choice	$0	$0			$186	$111			$476
5	Low Inc Non Choice	$385,619	$601,743			$1,978,207	$1,181,486			$8,832,748
6	Res Net Metering	$45,387	$70,825			$232,835	$139,061			$1,061,516
7	Emp Net Metering	$59	$92			$302	$180			$1,313
8	Low Inc Net Metering	$1,564	$2,440			$8,022	$4,791			$36,654
9	Total Residential	$9,950,733	$15,527,726			$51,046,941	$30,487,845			$228,199,195
10										
11	!i:•neral §iervlce 1 econda!Y									
12	GS1Sec Non Dmd Non Choice	$888,214	$1,604,004			$7,648,001	$3,546,837			$29,246,163
13	GS1 Sec Non Dmd Choice	$0	$0			$20,997	$9,737			$43,828
14	GS1 Sec Non Dmd Net Meter	$5,065	$9,146			$43,610	$20,225			$158,688
15	GS1 Sec Dmd Non Choice			$7,778,324	$13,077,335	$7,154,092	$2,610,992	$45,947,593	$16,769,253	$198,627,927
16	GS1 Sec Dmd Choice			$0	$0	$187,998	$68,613	$1,016,084	$370,835	$1,656,414
17	GS1 Sec Dmd Net Meter			$123,094	$206,953	$100,801	$36,789	$727,135	$265,378	$2,934,672
18	GS1 Sec Dmd Choice Net Meter			$0	$0	$2,696	$984	$16,100	$5,876	$25,864
19	Total General Service 1 Secondary	$893,279	$1,613,150	$7,901,418	$13,284,287	$15,158,195	$6,294,176	$47,706,910	$17,411,342	$232,693,556
20										
21	general §:ervlce 1 Prlma!Y									
22	GS1 Pri Non Dmd Non Choice	$1,922	$2,792			$8,479	$3,823			$44,246
23	GS1 Pri Non Dmd Choice	$0	$0			$410	$185			$700
24	GS1 Pri Dmd Non Choice			$936,947	$1,554,000	$2,241,172	$658,940	$2,996,921	$881,141	$22,543,358
25	GS1 Pri Dmd Choice			$0	$0	$486,020	$142,897	$520,343	$152,989	$1,303,579
26	GS1 Pri Dmd Net Metering			$5,293	$8,780	$13,462	$3,958	$16,932	$4,978	$133,530
27	Total General Service 1 Primary	$1,922	$2,792	$942,241	$1,562,780	$2,749,543	$809,804	$3,534,195	$1,039,109	$24,025,413
28										
29	General Service 2 Substation									
30	GS2Sub Non Choice			$612,745	$1,031,292			$715,713	$371,121	$12,650,933
31	GS2 Sub Choice			$0	$0			$3,391,441	$1,758,577	$5,236,417
32	Total General Service 2 Substation			$612,745	$1,031,292			$4,107,153	$2,129,698	$17,887,351
33										
34	general §:ervlce 2 Transm									
35	GS2 Tran Non Choice			$303,067	$478,192			$314,596	$45,550	$5,800,048
36	GS2 Tran Choice			$0	$0			$835,929	$121,034	$1,039,763
37	Total General Service 2 Transm			$303,067	$478,192			$1,150,524	$166,584	$6,839,811
38										
39	Irrigation									
40	Irrigation Non Dmd Non Choice	$20,668	$20,462			$41,842	$122,075			$489,859
41	Irrigation Non Dmd Choice	$0	$0			$0	$0			$0
42	Irrigation Non Dmd Net Metering	$77	$76			$156	$456			$1,703
43	Irrigation Dmd Non Choice			$359,793	$385,557	$193,231	$222,329	$1,478,593	$1,701,255	$8,854,590
44	Irrigation Dmd Choice			$0	$0	$316	$364	$3,614	$4,158	$8,675
45	Irrigation Dmd Net Metering			$556	$596	$381	$439	$2,284	$2,628	$15,315
46	Total Irrigation	$20,745	$20,538	$360,349	$386,152	$235,926	$345,663	$1,484,491	$1,708,040	$9,370,142
47										
48	Total Excluding Lighting	$10,866,679	$17,164,206	$10,119,820	$16,742,704	$69,190,606	$37,937,488	$57,983,275	$22,454,773	$519,015,467
49										
50	Total Company Owned Lighting	$107,057	$132,247			$1,077,608	$408,198			$13,808,633
51	Customer Owned lighting	$35,611	$43,990			$349,592	$132,426			$1,155,921
52	Total All Rates	$11,009,346	$17,340,443	$10,119,820	$16,742,704	$70,617,806	$38,478,111	$57,983,275	$22,454,773	$533,980,020

Detailed Rate c o m parison

Account No.	Description	Plant Ej_31/ 2017	Current Parameters Rate	Current Parameters Annual Accrual	NWE Proposal Rate	NWE Proposal Annual A= ual	MCCProposal Rate	MCCProposal Annual Accrual	MCC less Current Rates Rate	MCC less Current Rates Annual Accrual	MCCless Proposed Rates Rate	MCCless Proposed Rates Annual Accrual
	TRAN2M ISSIONPLANT											
350.20	Land Rights andRights-of-Way	30,727,757	1.71'16	525,445	**1.64'16**	503 ,935	**1.68'16**	515,954	-0.03'16	-9,4 91	0.04'16	12,019
352-00	Structur es and Improvements	30,995, 178	2.02'16	626,103	2.()()0..;	619,904	2.03'16	630,0 74	O.Ol '16	3,971	0.03'16	10,170
353.00	Station Equipment	249,370, 391	2.20'16	5,486,149	1.96'16	4,88 7,660	1.44'16	3,589,182	-0.76'16	-1,896,967	-0.52%	-1, 298,478
354.10	Towers and Fixtures	27,223,483	2.53%	688,754	2.30%	626,140	2.50'16	680,959	-0.03'16	-7,795	0.200..;	54,819
354.20	Clearing Land and Righ ts-of-Way	1,504, 241	1.93'16	29,032	1.77'16	26,625	,1 900;	28,608	-0.03'16	-424	0.13%	1,983
355.00	Poles and Fixtu r es	274,569 ,098	4.55'16	12,487,651	3.77'16	10,346 ,806	2.SS'16	7,084 ,04 2	-1. 97'16	-5,403,615	-1.19"-6	-3,262,764
355.20	Clearing Land and Rights-o f-Way	5,070,927	2.1l'16	107,070	1.66'16	84,341	1.SS'16	80,370	-0.53%	-26,700	-0.08'16	-3,97 1
356.00	overhead Conducto rs and Devices	143,978,985	l.88'16	2,702,346	1.83'16	2,629,159	2,()()0..;	2,874,328	0.12'16	171, 982	0.17'16	245 ,169
3 56 .10	SwitchingStation Equipment	14,656,645	2.17'16	317,690	2.08%	304,166	2.16'16	316,18 0	-O.Ol'16	-1,510	0.08'16	12,014
357.00	UndergrondConduit	137,878	1.87"A>	2,577	1.55'16	2,144	1.56'16	2,152	-0.31'16	-425	O.Ol'16	8
358.00	Underground Conductors and Devices	1,410,535	2.71%	38,195	2.20'16	31,043	2.10'16	29,640	-0.61%	-8,555	-0.10%	-1,403
359.00	Roads andTrails	2,519,64 1	1.29%	32,463	1.23'16	30,933	1.28%	32,225	-0.01%	-238	0.05%	1,292
	Total Transmission Plant	782,164,759	2.95%	23,043,481	2.57%	20,092,856	2.03%	15,863,714	-0.92%	-7,179,767	-0.54%	-4,229,142
	DISTRIBUTION PLANT											
360.20	Land Rights and Righ ts-of -Way	2,242,547	-0.42%	-9,406	-0.27'16	-6,043	-0.54%	-12,0 25	-0.12'16	-2,619	-0.27"-6	-5 ,982
361.00	Structu res andImprovements	19,088,103	2.07'16	395,438	2.02%	385,334	2.01%	384,605	-0.06"-6	-10,833	0.00"-6	-72 9
362 .00	Station Equipment	205,014,444	2.3l'16	4,728,010	1.97%	4,045,737	1.66%	3,394, 209	-0.65'16	-1 ,333,801	-0.32'16	-651, 528
364.00	Poles, Towers and Fixtur es	278,687, 203	4.83%	13,460,212	4.97".;	13 ,850, 248	4.49'16	12,510 , 393	-0.34%	-949,819	-0.48%	-1,339,855
365.00	Overhead Conductors and Devices	118,99 7,468	3.32%	3,950,765	3.87%	4,605,301	3.84'16	4,564, 035	0.52'16	613,270	-0.03%	-4, 1 266
366.00	Undergrou nd Conduit	116,024,132	2.07%	2,401,946	1.94%	2,251,064	1.91'16	2,218,370	-0.16"-6	-18 3,576	-0.0 3%	-32,694
367.00	Undergroud Conductors and Devices	200,069,425	2.84%	5,676,212	3,200..;	6,400,942	3.37'16	6,735,767	0.53'16	1,059,5 55	0.17%	334,825
368.00	Line Transformers	210,71 5,294	2.24%	, 4 713,967	2.28'16	4,802 ,683	1.82'16	3,839,491	-0.42'16	-874,476	-0.46'..	-963,192
369.10	overhead Services	34,429,051	3.83'16	1,318,419	3.89%	1,339,490	3.81'16	1,310,322	-0.02'16	-8,097	-0.08'16	-29,168
369.20	Underground Services	90,520,882	3.07'16	2,778,672	3.15%	2,851,334	2.190.	1,986,364	-0.88"-6	-792,308	-0.96%	-864,970
370.00	Meters	41,971,710	3.22%	1,351 , 266	3.14%	1,317,738	2.91%	1,221,765	-0.31'16	-ll 9 ,501	-0. 23%	-95,973
370.20	AMR Equipment	12,795,224	5.00",6	639,761	5,()()0..;	639,761	5.01%	641,056	O.Ol'16	1,295	O.Ol'16	1,295
373.10	Street Lighting Equipment	29,611,764	2.89"..	855,741	2.96%	876,504	2.98"A>	882,572	0.09%	26,831	0.02%	6,068
373.20	Yard Lighting	1,7 242,326	**4.22'16**	727,62 1	**3 .90",6**	672,448	3.11%	536,396	-1.1l'16	-191,225	-0.79'16	-136,052
373.30	Post TopLights	7,639,105	3.32%	253,607	3.29%	251,325	3.04%	232,382	-0.28%	-21, 225	-0.25'16	-18,943
	Total Distribution Plant	1,385,048,678	3.12%	43,242,231	3.20'16	44,283,866	2.92%	40,445,703	-0.200-6	-2,796,52 8	-0 . 28"-6	-3,838,163

Dave G tes Generating Station Depreciation Rate Proposals

Account	MVE Proposed	FEA/LCG Proposed	Delta
341	3.75%	3.10%	- 0.65%
342	3.75%	3.10%	- 0.65%
343	4.13%	3.38%	- 0.75%
345	3.75%	3.09%	- 0.66%
346	3.87%	3.19%	- 0.68%

Dave Gates Generating Station Test Period Depreciation Expense

Account	MVE Proposed	FEA/LCG Proposed	Delta
341	$829,212	$685,482	-$143,730
342.0	$329,922	$272,735	-$57,186
342.l	$228,599	$188,975	-$39,624
342.2	$233,403	$192,946	-$40,457
343	$4,009,633	$3,281,491	-$728,142
345	$339,338	$279,614	-$59,723
346	$910,653	$750,642	-$160,011
Total	$6,880 760	$5,651,886	$-1,228,873

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

IN THE MATTER OF NorthWestern Energy's Application for Authority to Increase its Retail Electric Utility Service Rates and For Approval Of its Electric Service Schedules and Rules.	))))	REGULATORY DIVISION DOCKET NO. D2018.2.12

STIPULATION AND SETTLEMENT AGREEMENT OF NORTHWESTERN ENERGY, THE MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY, THE MONTANA CONSUMER COUNSEL, AND WALMART

NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern"), the Montana Department of Environmental Quality ("DEQ"), the Montana Consumer Counsel ("MCC"), and Walmart (collectively "Stipulating Parties"), by and through their undersigned representatives, hereby submit to the Montana Public Service Commission ("Commission") this Stipulation and Settlement Agreement ("Agreement").

For settlement purposes, a fair and equitable resolution has been reached on the issues raised in this Docket concerning NorthWestern's E+ green tariff and other potential renewable energy products ("Settled Issues"). To reach a fair and equitable resolution of the issues that were raised or could have been raised by the Stipulating Parties regarding the Settled Issues, the Stipulating Parties stipulate and agree as follows:

1. Within thirty (30) calendar days from issuance of a Final Order from the Commission approving this Agreement, NorthWestern agrees to initiate a process to review its E+ green program and consider options for a new renewable energy product tariff, including but not limited to an option for non-residential customers. Such process shall include customer research and engagement with relevant and appropriate stakeholders, including DEQ, MCC, and Walmart, in transparent manner.

2. Within ninety (90) calendar days from issuance of a Final Order from the Commission approving this Agreement, NorthWestern agrees to make a progress report on the status of the initiated process with the Commission in a docket separate and apart from NorthWestern's Electric Rate Review Docket, Docket No. D2018.2.18. NorthWestern shall copy counsel for DEQ, MCC, and Walmart on the filing of the progress report.

3. No later than one hundred eighty (180) calendar days from issuance of a Final Order from the Commission approving this Agreement, NorthWestern agrees to make a filing to either modify its existing E+ green tariff, propose a new renewable energy product tariff,

or explain to the Commission why NorthWestern believes no change is necessary to existing tariffs.

4. This Agreement shall not constrain the rights of DEQ, MCC, or Walmart to file an alternative proposal to modify NorthWestern's existing E+ green tariff, to propose a new renewable energy product tariff, or to contest the filing described in paragraph 3 above.

The Agreement resolves all issues raised by the Stipulating Parties regarding the Settled Issues.

Except as specifically noted below, no individual Stipulating Party's position in this docket is accepted by any other Stipulating Party by virtue of its entry into this Agreement, nor does it indicate any Stipulating Party's acceptance, agreement, or concession to any rate making principle or legal principle embodied or arguably embodied in this Agreement.

The Stipulating Parties stipulate to the admission into the evidentiary record of all pre-filed testimony and exhibits of the witnesses for the Stipulating Parties to support the reasonableness of the Agreement and shall refrain from cross-examining the witnesses of the Stipulating Parties regarding the Settled Issues. The Stipulating Parties shall each call one witness at hearing to support this Agreement.

The various provisions of this Agreement are inseparable from the whole of the agreement between the Stipulating Parties. The reasonableness of the proposed settlement set forth in this Agreement is dependent upon its adoption, in its entirety, by the Commission. If the Commission declines to approve this Agreement as agreed to herein by the parties, or if the Commission adds or removes any terms or conditions not agreeable to the parties, either party shall, at its sole option, have the right to withdraw from this Agreement with all of its rights reserved. The Agreement and all its parts shall then be null and void, and the parties shall not be bound by any provision of it, and it shall have no force or effect whatsoever. In such event, the existence or terms of this Agreement shall not be admissible in any proceeding before the Commission or any court for any purpose.

The Stipulating Parties acknowledge that this Agreement is the result of a voluntary, negotiated settlement between them pursuant to ARM 38.2.3001, and agree that this Agreement, inclusive of the compromises and settlements contained herein, is in the public interest.

This Agreement may be executed in one or more counterparts and each counterpart shall have the same force and effect as an original document, fully executed by the Stipulating Parties. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signatures page(s).

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

IN THE MATTER OF NorthWestern Energy's Application for Authority to Increase its Retail Electric Utility Service Rates and For Approval Of its Electric Service Schedules and Rules.	))))	REGULATORY DIVISION DOCKET NO. D2018.2.12

STIPULATION AND SETTLEMENT AGREEMENT OF NORTHWESTERN ENERGY AND THE NORTHWEST ENERGY COALITION

NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern") and the NW Energy Coalition ("NWEC") (collectively "Stipulating Parties"), by and through their undersigned representatives, hereby submit to the Montana Public Service Commission ("Commission") this Stipulation and Settlement Agreement ("Agreement").

For settlement purposes, a fair and equitable resolution has been reached by the Stipulating Parties on the issues raised in this Docket concerning NorthWestern's electric Demand Side Management ("DSM") measures and/or programs, including capitalization and cost-effectiveness ("Settled Issues"). To reach a fair and equitable resolution of the issues that were raised or could have been raised by the Stipulating Parties regarding the Settled Issues, the Stipulating Parties stipulate and agree as follows:

1. The Stipulating Parties agree that NorthWestern will create a small (no more than 10 people), advisory stakeholder group consisting of relevant and appropriate stakeholders selected by NorthWestern, which shall include at minimum representatives from the NWEC, the MCC, and Commission staff, to discuss re-envisioning of the electric DSM programs offered by NorthWestern for the 2020-2021 program year (items to be discussed include branding, methods of marketing, cost-effectiveness calculations, energy savings estimates). The group shall make recommendations to NorthWestern for consideration in the development of the 2020-2021 electric DSM program offerings. Once the 2020-2021 program year commences, the group shall be disbanded. The Stipulating Parties will also include a 10% adder for electric DSM in its cost-effectiveness calculations beginning with the 2020-2021 program year, unless a different adder is required by Montana Administrative Rules and continue its work towards including a capacity value of electric DSM measures and/or programs in cost-effectiveness calculations.

2. With regard to recovery of electric DSM expenditures, the Stipulating Parties agree that NorthWestern shall record any DSM expenditures as a regulatory asset in the year the expenditures are incurred. NorthWestern shall also amortize these DSM expenditures over 10 years starting coincident with the Commission order that approves the expenditures for inclusion in rates at which time NorthWestern will earn a return of and

return on all electric DSM expenditures at the Rate of Return approved by the Commission, including any adjustment to Return on Equity ("ROE") for conservation investments pursuant to Montana Code Annotated Title 69, chapter 3, part 7. The Stipulating Parties agree that there should not be a threshold level of the DSM regulatory asset that triggers the need for a filing by NorthWestern.

3. The Stipulating Parties support implementation of the Fixed Cost Recovery Mechanism ("FCRM") pilot recommended by the Human Resource Council and National Resources Defense Council with no adjustment to the ROE. The Stipulating Parties support consideration of whether such an ROE adjustment would be appropriate if the FCRM was to become permanent as part of the study process envisioned by the pilot. If the study suggests a potential ROE adjustment might be appropriate, such potential ROE adjustment would be considered in NorthWestern's next electric rate review following the completion of the pilot.

4. Contingent upon implementation of the FCRM pilot, the Stipulating Parties support the use of both the Total Resource Cost Test and Utility Cost Test for electric DSM measure and program cost-effectiveness calculations. If measures and/or programs pass either test at a threshold of 0.9 or above (including the 10% adder), they shall be considered cost-effective. The Stipulating Parties agree that if any measures and/or programs fail to meet cost-effectiveness after the 2020-2021 program year and the reason the programs are not cost-effective is due to matters other than ramping costs, NorthWestern shall make best efforts to implement changes that result in such measures and/or programs becoming cost-effective, including but not limited to: increased/decreased incentive levels, administrative costs/investments changes, increased/decreased marketing, etc., and if unable to achieve cost-effectiveness, such measures and/or programs will be removed from the electric DSM offerings.

The Agreement resolves all issues raised by the Stipulating Parties regarding the Settled Issues.

Except as specifically noted below, no individual Stipulating Party's position in this docket is accepted by any other Stipulating Party by virtue of its entry into this Agreement, nor does it indicate any Stipulating Party's acceptance, agreement, or concession to any rate making principle or legal principle embodied or arguably embodied in this Agreement.

The Stipulating Parties stipulate to the admission into the evidentiary record of all pre-filed testimony and exhibits of the witnesses for the Stipulating Parties to support the reasonableness of the Agreement and shall refrain from cross-examining any remaining witnesses of the Stipulating Parties regarding the Settled Issues. The Stipulating Parties shall each call one witness at hearing to support this Agreement.

The various provisions of this Agreement are inseparable from the whole of the agreement between the Stipulating Parties. The reasonableness of the proposed settlement set forth in this Agreement is dependent upon its adoption, in its entirety, by the Commission. If the Commission declines to approve this Agreement as agreed to herein by the parties, or if the Commission adds or removes any terms or conditions not agreeable to the parties, either party shall, at its sole option, have the right to withdraw from this Agreement with all of its rights reserved. The Agreement and all its parts shall then be null and void, and the parties shall not be bound by any provision of it, and it shall have no force or effect whatsoever. In such event, the existence or terms of this Agreement shall not be admissible in any proceeding before the Commission or any court for any purpose.

The Stipulating Parties acknowledge that this Agreement is the result of a voluntary, negotiated settlement between them pursuant to ARM 38.2.3001, and agree that this Agreement, inclusive of the compromises and settlements contained herein, is in the public interest.

This Agreement may be executed in one or more counterparts and each counterpart shall have the same force and effect as an original document, fully executed by the Stipulating Parties. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signatures page(s).

[REMAINDER OF THIS PAGE IS BLANK.]

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the Notice of Staff Action issued on January 8, 2020 in Docket 2018.02.012 was served upon the following by mail and email to the addresses listed:

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Dated: January 8, 2020

/s/*Sydney Kessel*
Sydney Kessel, Administrative Assistant