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

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IN THE MATTER OF the Application by NorthWestern Energy 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. D2018.2.12

RESPONSE BRIEF
OF THE MONTANA CONSUMER COUNSEL

The Montana Public Service Commission ("Commission") should approve the *Amended Stipulation and Settlement Agreement of NorthWestern Energy, the Montana Consumer Counsel, the Montana Large Customer Group, the Federal Executive Agencies, and Walmart* ("Primary Stipulation").

The Commission should also approve the *Stipulation and Settlement Agreement of NorthWestern Energy, the Montana Department of Environmental Quality, the Montana Consumer Counsel, and Walmart* ("E+ Green Stipulation") to initiate a stakeholder process to examine NorthWestern's E+ Green Tariff. The record supports a similar approach for the special tariff requested by Malmstrom Air Force Base ("Malmstrom").

The Montana Consumer Counsel ("MCC") urges the Commission to approve these two above-noted stipulations and to deny the proposals for decoupling, capitalization of DSM, customer charge increases, special tariffs and additional reconnection fees, and reject efforts to shift additional costs and risks onto ratepayers. Specifically, the Commission should reject the proposal from the Human Resource Council and Natural Resources Defense Council ("HRC/NRDC") to decouple utility sales and revenues, as doing so would shift normal business risks to consumers and undermine cost control incentives. It should reject the *Stipulation and Settlement Agreement of NorthWestern Energy and the Northwest Energy Coalition* ("DSM Stipulation") because it would authorize NorthWestern Energy ("NorthWestern") to pursue demand-side management ("DSM") programs that are not cost-effective, increase the cost of DSM programs over time, and defer recovery of such costs to future generations.

The Commission should approve the proposal to create a new rate class and demand charge for customer-generators to improve price signals and prevent redistribution of the utility's fixed costs to other customers. It should maintain current fixed monthly charges and decline to impose a new reconnection fee. Finally, the Commission should order a jurisdictional cost of service study to better understand how costs should be allocated between NorthWestern's retail and wholesale customers.

I. Decoupling Shifts Risks and Reduces Cost Control incentives.

Decoupling is far from a new concept. HRC/NRDC's witness attempts to dismiss decoupling opponents as simply being fearful of something "new," Ex. HRC/NRDC-1 p. 7, but decoupling has been debated in regulatory circles since the 1980s, Ex. MCC-5 p. 6. In fact, it has been discussed and adopted in Montana in various forms starting with a multi-party stipulation, including MCC, that the Commission approved in 1994. *In Re Montana Power Company*, Docket No. 93.6.24, Order No. 5709d (1994); *see also*, *In Re NorthWestern Energy,* D2014.6.53, Order No. 7375a (2015) (Lost Revenue Adjustment Mechanism rescinded by the Commission). Despite this long history and decades of national debate, however, only 36 investor-owned electric utilities, a little less than 25%, in only 17 states, operate under a decoupling mechanism. Moreover, interest seems to be slowing, with few states moving forward with decoupling in the past several years. Ex. MCC-5 at 6. The Montana Commission should not join this small minority of other states.

Perhaps the Commission will hear more from decoupling proponents about how this case concerns the future, with appeals to modernity and the latest in regulatory fashion. This case is, indeed, about the future, as are most matters considered by the Commission. It would be foolish, however, to ignore the lessons of experience. Decoupling does depart from longstanding regulatory precepts that provide important ratepayer protections – the fundamental purpose of regulation.

The Commission must carefully assess whether these significant departures are outweighed by any benefits that are likely to be gained. The record in this proceeding strongly indicates that they are not.

Decoupling is intended to break the link between a utility's sales volumes and recovery of its fixed costs included in rates. The generally accepted purpose of decoupling is to remove disincentives for a utility to pursue energy efficiency resources. HRC/NRDC attempt to further broaden this objective to include distributed generation. Ex. HRC/NRDC-1 at 9. There is no dispute that such disincentives can theoretically exist. There is disagreement, however, over how operative they are in the larger scheme of utility regulation, whether utility behavior is affected to the extent that the negative consequences of a decoupling approach are worthwhile, and whether decoupling in this case will achieve the stated objectives.[1]

[1] The Commission should also recognize that presenting significant new proposals well past intervention and discovery deadlines can limit participation of potentially interested parties and is not conducive to a full discussion. NorthWestern filed its Application herein on September 28, 2018. HRC/NRDC did not file their decoupling proposal, which they label as a "Fixed Cost Recovery Mechanism," (FCRM) until February 12, 2019, well after the intervention deadline. NorthWestern's Opening Brief makes scant mention of the FCRM, and only in the context of the DSM Stipulation. HRC/NRDC are the main proponents and parties with the burden of supporting their proposal. No other party, aside from NorthWestern, will have an opportunity to respond in briefs to what is effectively the main argument on these issues. If the Commission is inclined to consider adoption of a decoupling mechanism, it may want to defer such consideration for this reason alone.

A. Decoupling Would Undermine Longstanding Consumer Protections

It is indisputable that the proposed decoupling mechanism by its very nature abandons test period rate making. It would adjust rates based on one change, and ignore all other changes. To simply dismiss this issue by claiming, as HRC/NRDC witness Ms. Levin does, that "the 'matching principle' is not a principle at all," reveals a lack of familiarity with the rate setting process. HRC/NRDC Ex. 1, 27:7-8. Indeed, she acknowledges that she has no experience in constructing a revenue requirement analysis. Hr'g Tr. 2424:15-22. Matching is a concept as basic as accounting itself; would the Commission countenance ledgers of debits and credits from different time periods? Matching is a fundamental principle that has been relied upon by virtually all regulators for many decades. Examples are easily found in Montana Commission orders:

> The Commission finds the rationale behind adoption of a test year to be the matching principle, and seeks, as nearly as possible to match revenues, expenses and plant within that period MPC, in criticizing MacGregor [an industrial intervenor witness] explained this in its brief:
>
> > Without belaboring the point, it is fair to say that Mr. MacGregor in seeking offsets to the revenue requirement of the capacity additions presented in the Company's filing, would have the Commission mis-match selected 1984 items with adjusted 1982 expenses. The result is a serious mis-match that tells the PSC very little about the actual revenue requirement of Montana Power. (p. 48).
>
> The Commission's consistent support of the historic test year adjusted for known and measurable changes is well known as a matter of policy and rate case precedent.

Montana Power Co., Dkt. 83.9.67, Order 5051c, p. 41 (1984).

Ms. Levin carelessly asserts that "those who make the matching principle argument focus solely on customer harm," and that there is some "hidden rationale" behind the matching principle concerns. Ex. HRC/NRDC-1 at 17, 28. The preceding example, however, again underscores Ms. Levin's inexperience, as it clearly illustrates a *utility* raising this issue and expressing a *utility* concern that proper application of matching is essential. It is a matter of fairness for *all* parties. The Commission has reiterated its conclusions about the importance of matching in other cases:

> The MCC's motion for reconsideration addresses the issue of the Commission's acceptance of a load forecast which does not match test period loads. MCC states that to accept a forecast that does not match in the test year, "endangers a fundamental aspect of regulatory oversight to which it has adhered faithfully over the years; i.e., the need to match test year revenues with test year expenses" (MCC MFR, p. 7).
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> On reconsideration, the Commission agrees with MCC on this point.

Montana Power Co., Dkt. 88.6.15, Order 5360e, p. 9 (1989).

> MPC cannot justify its requested rate increase based only on increased QF costs. The Commission has traditionally rejected single-issue filings for good reason. As MCC and LCG commented, load growth and the replacement of MPC-owned generation with a power buyback contract might also have affected MPC's costs and revenues. The positive and negative impacts of all these changes should be considered together in determining whether a rate increase is justified, even on an interim basis.

Montana Power Co., Dkt. D97.7.90, Order 5986r, ¶ 23 (2000).

The existence of very limited exceptions to the matching principle such as the electricity and gas supply cost trackers which are cited by Ms. Levin, HRC/NRDC-1, 27:13-15, does not support an argument to entirely discard this fundamental accounting and ratemaking concept. First, these are exceptions that have largely existed even while the Commission has emphasized the general rule of matching as expressed above. In addition, such exceptions are statutorily prescribed, or based on a four-part test including large recurring costs that fluctuate and are beyond the utility's control. There is no basis in this case to carve out an exception to the matching requirement.

B. Efficiency Incentives Would Be Weakened Under Decoupling.

It is likewise true that a fundamental and intended effect of test period rate making is the promotion of efficiency. One of the more unfortunate aspects of the decoupling proposal would be misaligning the Company's current incentive to control its costs and rates so as to stave off price-induced conservation. As Alfred Kahn observed, "if effectiveness were defined, as it obviously ought to be, with an eye to the institutional requirements for efficiency and innovation, public utility commissions ought not even to *try* continuously and instantaneously to adjust rate levels in such a way as to hold companies continually to some fixed rate of return…" Alfred E. Khan, The Economics of Regulation: Principles and Institutions, Volume

II, p. 48, 1988, MIT Press; MCC-5, fn.26. The decoupling proposal here would do exactly that as it tries to provide assurance of revenue levels.

While there is a common misperception that utilities are guaranteed certain profits, the Commission has long correctly held that it does not guarantee any level of utility revenues or profits. As Ms. Levin acknowledged, however, the decoupling proposal is designed "to enable the utility to recover its fixed costs regardless of how much energy it sells. Nothing more, *nothing less*." Ex. HRC/NRDC-1 at 13 (emphasis added). If decoupling were to be adopted, barring the extremely unlikely loss of customers, the utility would effectively be guaranteed a certain level of revenue, regardless of external factors such as weather or general economic conditions. This inherent element of the decoupling proposal is unlike the competitive environment which regulation strives to emulate.

HRC/NRDC acknowledge that higher prices generally discourage sales, and that is why they oppose higher fixed charges that would reduce volumetric charges. Hr'g Tr. 2379:3-11; 2388:14-22. Ms. Levin further acknowledged that a business interested in maintaining sales would therefore be interested in controlling the cost of its product. *Id*. at 2379:12-15. Decoupling is intended to make a utility indifferent to sales, however, breaking this important connection with cost control incentives. In other words, decoupling would compensate NorthWestern for sales losses due to inefficiencies such as higher tracker costs that lead to sales reductions. Ms. Levin tried to downplay this significant problem by arguing that "a decoupling mechanism … only ensures a level of revenue," and that revenue is different than earnings. *Id*. at 2379:20-22. Her distinction misses the point, which she subsequently acknowledges:

> Q. If price increases caused reduced consumption, your decoupling mechanism protects NorthWestern against those sales losses; doesn't it?
>
> A. Yes, it would.

Id. at 2380:16-19.

To counter these obvious cost control concerns, HRC/NRDC also creatively argue that decoupling actually increases cost control incentives because sales increases can no longer increase profits. Ex. HRC/NRDC-1 at 29. This simplistic suggestion, of course, turns a blind eye to the reality that a decoupled utility can be comfortable in the knowledge that sales downturns, regardless of cause, will not affect a fixed revenue level; i.e., they have vastly fewer threats to earning target return levels. Such continuous rate adjustments, to use Alfred Kahn's terminology, significantly blunt normal efficiency motivations and lead to a misalignment of incentives. As Dr. Dismukes emphasized, "the discipline imposed by the regulatory process until a utility's next base rate case ('regulatory lag') is removed." Ex. MCC-5 at 21.

C. The Record Does Not Establish a Need for Decoupling.

As discussed above, it is undeniable that revenue decoupling undermines longstanding consumer protections. One would think, then, that a compelling justification must exist to prompt such an otherwise damaging course of action. The record in this case, however, falls far short of that mark. It does not establish any concrete benefits that would justify such a significant and unfortunate departure. When asked about the need for decoupling, Ms. Levin first responds at great length with unpersuasive and contradictory platitudes. Ex. HRC/NRDC-1 pp. 4-7. For example, she contends that decoupling is a "vital first step towards modernizing our electric utilities," while at the same time claiming that existing technological progress has already "irrevocably changed the nature of electric utilities." *Id*. at 7. One of the changes she notes is that new energy sources allow "independent power producers to offer generation at comparable or lower cost than regulated utilities." *Id*. at 6. This circumstance, of course, does not apply in Montana where such third-party supply is prohibited.

HRC/NRDC next turn to the more specific and traditional argument of decoupling proponents, i.e., energy efficiency and the "throughput incentive." Without any stated evidence at all, Ms. Levin asserts that NorthWestern "does not want to promote or achieve all cost-effective efficiency measures." Ex. HRC/NRDC-1 at 8. Notably, she does not provide one example. This is an entirely theoretical conclusion, and ignores the fact that regulation is more complex than

Ms. Levin describes and involves a system of incentives. This also ignores that NorthWestern in fact has proposed and is pursuing cost-effective demand side management programs. Because HRC/NRDC are the proponents of this decoupling proposal, they have the burden of proof which they have failed to meet. Not only is the record devoid of support, rather it affirmatively demonstrates the lack of justification. NorthWestern has currently budgeted $153.1 million over the next 18 years for energy efficiency programs. Ex. MCC-5 at 11. This level of commitment is transparent and if the Commission is persuaded it is insufficient, it can order more.

The Commission knows that NorthWestern engages in significant energy efficiency measures, as it is required to by law, Commission regulations, and public utility obligations. Failure to acquire cost effective resources would subject NorthWestern to potential cost disallowances that could far outweigh the impact of a temporary loss of some fixed cost recovery associated with sales fluctuations that may occur between rate cases. This regulatory scrutiny and threat of disallowance of imprudently incurred costs provides strong incentives. The resource planning process in Montana makes it possible to identify such utility failures. If the Commission or parties believe that there is a resource planning and acquisition problem, it can and should be dealt with in the appropriate context. There is no need to dismantle other consumer protections.

In an attempt to justify decoupling because of modern circumstances and "things changing," HRC/NRDC undercuts their own position. They claim that decoupling is necessary because "sales have been flat – or even declining – due to new efficiency standards and codes, structural shifts in the economy, and new information technology options." Ex. HRC/NRDC-1 at 6. In other words, efficiency has occurred even in the absence of decoupling.

HRC/NRDC extend the energy efficiency disincentive argument to "customer-sided technologies" and distributed generation. *Id*. at 9. Again, no specific examples of failures of the regulatory process that would be improved by decoupling are provided. The discussion is entirely based on an incomplete and therefore flawed theoretical analysis, and provides no basis for the proposed course of action. It is true that "each kWh of distributed solar that is used by a home is a kWh sale lost." *Id*. The growth of distributed solar on Northwestern's system does not support a conclusion that NorthWestern has impeded this development, however. Moreover, what is left unsaid is that HRC/NRDC's decoupling proposal would make NorthWestern whole for this temporary fixed cost recovery loss associated with increased distributed customer self-generation by spreading it back to all ratepayers. The appropriate recovery of fixed costs from customers with self-generation is an issue that NorthWestern has proposed to address with its rate design proposals in this proceeding. Finally, as this case aptly demonstrates, there are many motivated and effective advocates for distributed generation. It must be recognized in this setting, as Ms. Levin does, that NorthWestern is not in a position to set its own rates so as to discourage such activity. Hr'g Tr. 2373:1-8.

While adamant that they are not proposing inverted block or time of use rates, HRC/NRDC's final justification for their decoupling proposal is to support a Commission directive that NorthWestern itself propose such "modern" rate designs. Ex. HRC/NRDC-1 at 22, 24; Hr'g Tr. 2389:2-24. There is absolutely no evidence in this record, however, that such rates would be cost-based, just and reasonable, or beneficial in any way to NorthWestern's ratepayers. Thus, there is no basis to conclude that such a commitment has any value. Additionally, as Ms. Levin acknowledged, there is nothing that prevents HRC/NRDC or any other party from proposing such rate designs and supporting them with analysis and testimony in the next or in any rate case. In fact, unbeknownst to Ms. Levin, the Commission has in the past both adopted such rates and required utilities to present them, as many as 38 years ago. Hr'g Tr. 2391:10-2392:11; *In Re Montana-Dakota Utilities*, Docket No. 81.1.2, Order No. 4799 (1981). The HRC/NRDC "modern" rate design justification is thus a red herring in the context of a decoupling proposal.

Not only is there no need established in this case to justify decoupling, it is a concept that could actually be at odds with the currently evolving energy landscape. Electrification of fossil fuel applications, the most prominent being electric vehicles, is an emerging trend, as recognized by Ms. Levin. Hr'g Tr. 2373:9-2374:15. These are apparently viewed as "good" sales by HRC/NRDC and they propose adjustments in other states to support related investments. Hence, NorthWestern may experience increased load growth in the future that more than compensates for any reduction in throughput due to efficiency efforts and these may be increases that the Commission and others want to encourage rather than discourage.

D. The Mechanics of Decoupling Are Skewed Against Ratepayers.

HRC/NRDC's decoupling proposal reaches far more broadly than the energy efficiency and distributed generation issues used to justify it. It would protect the utility against sales declines between rate cases, no matter the cause. At the same time, it does not require any particular level of energy efficiency participation or savings, effectively also decoupling energy efficiency performance from financial returns. Ex. MCC-5 at 11. As a result, there is no direct connection between the concerns HRC/NRDC raise and the mechanism they have proposed to address those concerns.

As noted above, Ms. Levin acknowledges that decoupling would protect NorthWestern from price-induced sales losses. She also acknowledges that decoupling would protect NorthWestern from sales losses due to effects of economic downturns and weather, for example. Hr'g Tr. 2381:23-6. The other factor that has a significant impact on sales volumes is customer growth. As opposed to the other effects of customer conservation, economy and weather, customer growth is the one factor that reliably *increases* sales volumes. Ex. MCC-5 at Ex. DED-6.

In its revenue-per-customer proposal, however, customer growth is the one element that HRC/NRDC propose to *not* decouple. Transmission and distribution-related revenues would be allowed to increase based on these increased customer levels. HRC/NRDC attempt to justify this inconsistency with the rationale that they are recognizing increased costs between rate cases. Hr'g Tr. 2384:24-2385:4. There are several problems with this rationale. First, in now trying to accommodate some cost changes, HRC/NRDC is being arbitrarily and unfairly selective, choosing to ignore the full set of cost changes between rate cases as noted above in the matching discussion. In addition, HRC/NRDC's assumption of increasing costs is admittedly based in part on general inflation, while the Commission has not accepted such inflation adjustments. Finally, Dr. Dismukes explains that HRC/NRDC's presumed strong connection between distribution and transmission costs and customer counts does not exist, as demonstrated by NorthWestern's cost of service analyses in this case. Ex. MCC-5 at 25-26.

HRC/NRDC's decoupling proposal would shift economy-related and weather risks, among others, to ratepayers. HRC/NRDC propose to limit the potential adverse impacts of their proposal by imposing a three percent cap on the annual rate adjustments that would result. Any excess amounts would be carried over to future periods, however, even if the Commission terminates the decoupling mechanism. As proposed by HRC/NRDC, there is no cap on the deferrals and they would include interest charges. The rate cap could actually increase volatility, adding a surcharge due to a warmer year to increased bills from a following colder year, for example. Hr'g Tr. 2384:16-23. HRC/NRDC incredibly claim that their approach can stabilize bills, but as Dr. Dismukes notes, surcharges or rebates are not contemporaneous and instead would be "calculated on an annual basis and applied to the following year's customer bills." Ex. MCC-5, 19:1. Moreover, if this is a concern that needs to be addressed, NorthWestern has long offered budget billing that is much more stabilizing than decoupling surcharges. Furthermore, NorthWestern's budget billing plans, in sharp contrast to HRC/NRDC's mandatory decoupling surcharges, also offer ratepayers the ability to opt in or out. Hr'g Tr. 2315:10-20. Consumer satisfaction can be promoted by offering a choice. For those who want bill stability, the NorthWestern budget billing plans are available, and ratepayers can opt into such programs.

E. Decoupling Would Require Adjusting the Rate of Return

If despite all of the compelling arguments against decoupling, the Commission nevertheless determines that a decoupling mechanism should be approved for NorthWestern, it must adjust the Company's rate of return that was agreed to in the Primary Stipulation which assumed there is no decoupling in place. In HRC/NRDC witness Levin's own words, the decoupling mechanism is intended to address a concern regarding "shareholder welfare." Ex. HRC/NRDC-1 at 8. She further notes that the mechanism will "reduce risks to customers, investors, and the utility." *Id*. at 30. While any reduced risks to ratepayers are debatable, the critical point here is that the Commission must set a return on equity for the utility to reflect *its* costs, based on its *own* risks, which are reduced by the decoupling proposal. Hr'g Tr. 2266:1-4. If shareholder welfare is supported by decoupling, but not recognized in authorized capital costs, then ratepayers are being disadvantaged.

Without an appropriate return adjustment, customers will be providing a return commensurate with a rate design based on throughput (kWh sales), while the utility and its shareholders no longer shoulder that risk (their risk has been reduced because unit sales no longer determine realized revenues). Without adjustment, customers would pay for that risk associated with revenues based on throughput even though decoupling has eliminated that risk. Ex. MCC-6 at 3.

HRC/NRDC conducted a modeling exercise that purports to show decoupling would result in more negative than positive adjustments. Mr. Hill notes, however, that actual national averages have shown rate increases 62% of the time and decreases only 38% of the time. More importantly, he explains that decoupling would reduce revenue volatility, as Ms. Levin also recognizes, and that "volatility of the utility's revenue stream is a factor that determines risk and the appropriate return." *Id*. at 4, 7. As noted above, Ms. Levin explicitly acknowledges that decoupling "ensures a level of revenue." Hr'g Tr. 2379:20-22. "Utilizing a decoupling program for utilities without a concomitant downward adjustment to the allowed return, then, would create utility *rates that exceed costs*." Ex. MCC-6 at 9 (emphasis added).

Failure to provide a downward rate of return adjustment to recognize this fundamental change in reduced risk to the Company would result in rates that are not just and reasonable. This is not an extraordinary idea. While decoupling is distinctly a minority approach, among the Commissions that have adopted decoupling there is abundant precedent and support for a rate of return adjustment. Dr. Dismukes provides 19 examples of such adjustments. Ex. MCC-5 at Ex. DED-7.

Turning to the appropriate level of an adjustment, MCC witness Hill provided a detailed mathematical analysis of NorthWestern's quarterly revenues over the past ten years and demonstrated that a decoupling regime would substantially lower the volatility of the Company's net revenues (i.e., those revenues that are not already subject to true-up mechanisms). Mr. Hill's analysis showed that if a decoupling mechanism is allowed in this proceeding, the Company's investment risk and cost of capital will be reduced. He showed, further, that a conservative estimate of that cost of equity capital reduction is 25 basis points. Ex. MCC-6 at 22.

II. The DSM Stipulation Would Shift Higher Costs to Future Generations.

The DSM Stipulation between NorthWestern and the NW Energy Coalition ("NWEC") would allow the Company to profit from spending money on energy efficiency programs that fail traditional cost-effectiveness tests. Except for the proposed stakeholder process, the DSM Stipulation is contrary to the public interest and likely to result in additional rate increases beyond those agreed to in the Primary Settlement.

A 10% adder is not necessary to promote cost-effective efficiency programs. In fact, such an adder would explicitly authorize NorthWestern to acquire *non*-cost-effective DSM. Such an outcome would not be consistent with the obligation to provide "service at the lowest long-term total cost." § 69-8-419(2), MCA. The parties to the DSM Stipulation support the use of the Total Resource Cost Test and Utility Cost Test. Under both these tests, DSM is traditionally not cost-effective if the measure is below 1.0. Preapproving a 10% cost-effectiveness adder is contrary to the public interest because it will result in NorthWestern charging ratepayers for DSM that is not cost effective compared to available alternatives.

Capitalization of annual DSM expenses is also not in the public interest, and NorthWestern should continue to recover 100% of prudently incurred DSM costs through an annual cost-tracking adjustment, possibly filed contemporaneously with the Power Cost and Credits Adjustment Mechanism ("PCCAM"). Capitalizing DSM costs would result in higher DSM costs because consumers would become responsible for both the actual expenses of the programs and paying NorthWestern a return over time for those expenses. Such treatment is not necessary to ensure that NorthWestern acquires cost-effective DSM.

Given the recent creation of the PCCAM and the passage of Senate Bill 244, the Commission should approve a specific cost-tracking adjustment in this case in order to continue tracking 100% of DSM expenditures annually. Senate Bill 244 specified a ratio of 90:10 customer-to-shareholder sharing of costs only "if cost sharing is required" as part of "a cost-tracking adjustment." S. 244, 66th Leg., (2019). Thus, the Legislature has given the Commission discretion over whether to require sharing of costs for each cost-tracking adjustment that it approves. Nothing requires the Commission to mandate cost sharing for a DSM cost-tracking adjustment simply because it previously mandated cost sharing for a fuel and purchased power cost-tracking adjustment. Since DSM costs were explicitly excluded from the PCCAM, the Commission remains free to approve a DSM cost-tracking adjustment that does not require cost sharing, just as it did with MCC and PSC taxes.[2]

If despite these concerns the Commission nonetheless allows NorthWestern to capitalize DSM expenditures, then it should require NorthWestern to record them as a regulatory asset in the year they are incurred and to start amortizing them over ten years starting January 1 of the following year.[3] If NorthWestern's unamortized DSM regulatory asset balance reaches $45 million, then it should be required to

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[2] The Commission ordered that MCC and PSC taxes "shall be treated separately, as outside the base costs and tracking mechanism, and are subject to full recovery…." Final Order 7563c, Dkt. D2017.5.39, ¶¶ 62, 76-77 (Sept. 18, 2018).

[3] For example, NorthWestern would commence amortization of DSM costs incurred in 2020 over ten years starting on January 1, 2021. For DSM costs incurred in 2021, it would start amortizing such costs on January 1, 2022.

make a filing with the Commission within 45 days showing: (1) the amount of the DSM regulatory asset, including details on cost deferrals; (2) return amounts recorded and amortization to-date; and (3) a plan for cost recovery. Requiring such a filing will avoid an excessive build-up of DSM regulatory asset balances between rate cases. Ex. MCC-1 p. 81.

Commencing amortization after the year in which DSM costs are recorded into a regulatory asset would be consistent with treatment of NorthWestern-owned generation resources. When plant additions are placed into service, depreciation commences at that time and is not deferred for years before NorthWestern has another rate case. Similarly, if the Commission is inclined to allow DSM costs to be deferred as a regulatory asset, amortization should commence without years of delays.

Amortization is also necessary to match the period benefitted with the period in which cost is recognized on NorthWestern's books, to promote generational equity. If cost-effective DSM is acquired by NorthWestern, then the costs and benefits of that acquisition should both commence shortly thereafter. Proper matching of costs and benefits over time is a bedrock accounting and regulatory principle. Commencing amortization of deferred DSM costs in the year following cost incurrence will assure that the costs are recognized roughly during the period benefitted by the DSM spending.

None of these protections would be necessary if the Commission simply accepts MCC's primary recommendation to continue tracking 100% of actual DSM costs through annual filings. Only if the Commission allows NorthWestern to record DSM costs as a regulatory asset are certain consumer protections necessary to avoid excessive rates and generational inequity.

III. A Demand Charge for Future Customer-Generators is Reasonable.

Recent legislative enactments and the growing number of customer-generators suggest that now is the right time to establish a fairer rate structure that will send better price signals for future net metering systems. In 2017, the Montana Legislature required NorthWestern to study the costs and benefits of customer-generators. § 69-8-610, MCA. It authorized the Commission to "establish appropriate classifications and rates" for customer-generators based on their costs and benefits to the utility system. § 69-8-611, MCA (also authorizing "subclassifications" based on differences between net metering systems, separate rates for production and consumption, and separate metering).

Importantly, the Legislature grandfathered every customer-generator that interconnects prior to the Commission's final order in this case (assuming it approves a new classification of service in this case). § 69-8-612, MCA. If the Commission does not approve a new classification of service for customer-generators in this case, however, then new customer-generators will continue to be grandfathered at the full retail rate indefinitely, at least until the next general rate case. § 69-8-611, MCA. Considering how much time has elapsed since the last general rate case and the growing number of net metering systems, now is the time to create a new rate class and a fairer rate design.

As currently structured, net metering allows customer-generators to avoid charges for transmission and delivery services that they continue to consume. As a result, customer-generators create more costs than benefits and cause cross-subsidies with other ratepayers. Ex. MCC-4b pp. 22-23. MCC witness Dr. David Dismukes estimated that the net benefit of customer-generated solar is approximately $0.04 per kilowatt-hour, as compared to the current retail rate credit of approximately $0.11 per kilowatt-hour. For NorthWestern to recover this difference, it must be redistributed to other customers. A new classification of service is therefore justified to address this situation.

The unique load patterns and physical characteristics of customer-generators also justify the creation of a new rate class. Hr'g Tr. 2210-2214. Customer-generators already have meters capable of measuring demand and can respond to demand charges by reducing demand at least to some degree, perhaps to a greater extent than other residential customers. *Id*. (suggesting customer-generators are more "cognizant" of their energy usage than other residential customers).

While the Legislature grandfathered existing customer-generators who already invested in net metering systems, it also instructed the Commission to determine whether cross-subsidization is occurring and gave it every tool necessary to reduce cross-subsidization going forward. Although there are multiple ways this cross-subsidization could be addressed, in this case NorthWestern proposes a demand charge. The MCC's recommendation incorporates the ratemaking principle of gradualism into this issue. Under this approach, "The only change is the conversion of existing transmission and distribution energy charges to equivalent demand rates." Ex. MCC-5 p. 79. MCC's proposed demand charge of $4.49 per kilowatt ("kW") is designed to collect the same amount of transmission and distribution revenues that have been collected from customer-generators through volumetric energy charges. *See* Hr'g Tr. 2201-2202. It is thus a modest proposal compared to the proposals from other parties in this case.

For example, if the Commission maintains the existing customer charge of $4.10 per month and accepts MCC's recommendation, then a customer-generator with an average monthly demand of 5.81 kW could reduce their total electric bill to about $30.00 if their generation entirely offsets consumption over the year.[4] § 69-8-603, MCA (allowing carry-forward of excess kilowatt-hour credits for up to one year). If their demand is less than average, then their bill would be lower. Such an outcome is not unreasonable to future customer-generators who will continue to use NorthWestern's transmission and distribution systems.

[4] $4.10 + (5.81 kW x $4.49) = $30.19

IV. Fixed Customer Charges Should Not Be Increased.

Accepting NorthWestern's proposal to increase customer charges by anywhere from 18% to 40% depending on the class would "reduce economic incentives for ratepayers to control monthly utility bills through efficiency and conservation efforts" and would "shift the rate burden within a customer class to lower-use customers." Ex. MCC-4b pp. 55, 57. Neither of these would be desirable outcomes in this case. Regulation should serve as a substitute for competition, and volumetric recovery of fixed costs is common in competitive markets. Thus, no increase to NorthWestern's customer charges is warranted at this time, and any rate changes contemplated by the Primary Stipulation can be effectuated through volumetric rates.

V. A Jurisdictional Cost Study Is Justified.

Efforts to allocate costs between NorthWestern's retail and wholesale jurisdictions have been made in the context of the Dave Gates Generating Station ("DGGS"), annual tax trackers, and in this case. As a recurring issue that is likely to continue to arise, it should be studied directly.

In the case of DGGS, for example, the Commission preapproved a Montana jurisdictional cost premised on the assumed approval by the Federal Energy Regulatory Commission ("FERC") of a corresponding charge for balancing service to FERC-regulated customers. However, FERC strongly disagreed with

NorthWestern's case and rejected its advocacy. NorthWestern did not return to this Commission to request that the company be "made whole" for the revenues it did not recover when the two jurisdictions failed to agree. However, the effect of the Company's proposal here is that the Montana ratepayers automatically make the Company whole for any residual costs associated with its transmission business. This is true for FERC methodological differences, as well as simply timing of FERC filings and rate changes. It is understandable that NorthWestern seeks to avoid risk in this situation. It is not clear how Montana ratepayers would benefit from guaranteeing NorthWestern's transmission cost recovery.

NorthWestern forwards two arguments to support its continued practice of crediting retail ratepayers with FERC jurisdictional revenues. It contends that "this method most fairly assigns costs to the cost-causer" (NWE Opening Brief, p. 36), and that it is applying "long-standing precedent." Neither of these assertions is true. First, it is clear that FERC-jurisdictional consumers cause some of the costs of the transmission system, otherwise their rates would be zero. Yet, NorthWestern "assigns" 100% of these costs to retail customers to be offset by FERC-related revenues at whatever level FERC might approve. This arrangement is obviously not an assignment to "cost-causers." Second, there is no precedent to establish this method of cost allocation. NorthWestern cites Docket Nos. D2007.7.82 and D2009.9.129. Both of these dockets were resolved by stipulations approved by the Commission. Both Stipulations, agreed to by NorthWestern, included an explicit recitation that they do not "create any … precedent of the Commission." Order No. 7046h (December 9, 2010), Attachment A, Stipulation and Settlement Agreement of NorthWestern Energy and the Montana Consumer Counsel. Mr. Cashell testified at hearing that he was not aware of that language. Hr'g Tr. 560:14. The Commission has explicitly found to the contrary that "(p)roper allocation between jurisdictions is necessary to ensure that ratepayers are paying for their fair share of costs." *In Re Montana Power Company*, Docket No. 88.6.15, Order No. 5360d, ¶ 479 (1989).

NorthWestern urges the Commission to look the other way now, because "…it is likely that [the currently requested FERC rates] will still be more than the current rate…" NWE Opening Brief, p. 37. This argument misses the mark entirely. Since NorthWestern has not updated its FERC rates in many years, it is not hard to imagine that such rates will be increasing from current levels. This is small comfort if they are still set too low. Theoretically, they will not be, but the Montana Commission has an independent responsibility to determine costs properly attributed to retail ratepayers. FERC should not be setting rates by default for Montana retail jurisdictional customers, if for no other reason than the state Commission does not control the timing of NorthWestern's FERC filings. The Montana Commission has recently affirmed this principle. D2017.11.86, Order No. 7580a, 7 (Jan. 29, 2018) (rejecting a revenue credit method for allocating tax expense between wholesale and retail jurisdictions). The Commission found that a revenue credit method for allocating costs "appears to provide NorthWestern a financial disincentive to request wholesale rate changes that would result in a more appropriate allocation of property taxes." *Id*., at ¶ 18.

The objective of a jurisdictional cost study would not be complete assurance of cost recovery for NorthWestern (e.g., by setting up retail ratepayers as the ultimate guarantors for that recovery), but rather the proper allocation of costs between jurisdictions. The MCC proposes this analysis to assist the Commission and the parties in evaluating the costs that NorthWestern incurs to serve customers in the respective jurisdictions. Parties will be able to weigh in on the study results in NorthWestern's next base rate case. The Commission should order a jurisdictional cost of service study to better inform its decisions regarding recovery of the costs incurred in serving ratepayers subject to its retail jurisdictional rates.

VI. The Commission Should Defer Acting on Any Choice Tariffs.

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. The legality of any arrangement under § 69-8-201, MCA may depend on how that arrangement is structured. Malmstrom acknowledged at hearing that "there are likely better measures of the value of this hydropower to NorthWestern and Montana consumers" than the approved QF-1 rate for hydropower. Hr'g Tr.

1092-1093 (conceding "our original proposal could be improved upon."). Both Malmstrom and NorthWestern have raised legitimate issues concerning Malmstrom's ability to access low cost federal hydropower. However, all parties appear to agree that the record in this case simply does not support the Commission taking action at this time.

Similarly, the E+ Green Stipulation reflects the agreement of four parties that stakeholder discussions and a future filing from NorthWestern to either preserve, modify or replace the current E+ Green Tariff are appropriate. Such a process will enable a more deliberate and fluid discussion of the relevant issues concerning any green energy offering. If the Commission approves the E+ Green Stipulation and initiates that process, then no further action is necessary at this time.

VII. A New Reconnection Fee Is Unnecessary and Should Be Rejected.

The after-hours reconnection fee of $150 proposed by NorthWestern is not specifically addressed in the Primary Stipulation and is not necessary to ensure a reasonable outcome in this case. Instead, "The proposal is a solution in search of a problem." Ex. MCC-4b p. 61. After-hours reconnection requests account for less than one-fifth of all reconnection requests, there is no evidence that they are on the rise, and the Company has operated adequately without them. *Id*. Since the Primary Stipulation already provides an opportunity to earn a reasonable return, additional revenue generated by a new reconnection fee is not necessary and would simply increase profits. With most consumers already facing a rate increase as a result of the Primary Stipulation, adding new fees on top of those increases is not necessary or appropriate.

Respectfully submitted July 31, 2019.

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