PRE-FILED DIRECT TESTIMONY

OF JENNIFER E. NELSON

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

I. Witness Introduction

Q. Please state your name, affiliation, and business address.

A. My name is Jennifer E. Nelson. I am an Assistant Vice President at Concentric Energy Advisors, Inc. ("Concentric"). Concentric is a management consulting firm that provides regulatory, financial, and economic advisory and litigation support services to energy and utility clients across North America. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. On whose behalf are you submitting this Direct Testimony?

A. I am submitting this Direct Testimony before the Montana Public Service Commission ("Commission") on behalf of NorthWestern Energy ("NorthWestern" or "Company").

Q. Please describe your education and experience.

A. I have worked in the energy industry for fourteen years, having served as a consultant and energy/regulatory economist for state government agencies. Since 2013, I have provided consulting services to utility and regulated energy clients on a range of financial and economic issues including rate case support, ratemaking policy, and regulatory strategy issues. Prior to consulting, I was a staff economist at the Massachusetts Department of Public Utilities. I attended utility regulatory training offered by the New Mexico State University's Center for Public Utilities and have earned the designation of Certified Rate of Return Analyst from the Society of Utility and Regulatory Financial Analysts. I hold a Bachelor of Science degree in Business Economics from Bentley College (now Bentley University) and a Master of Science degree in Resource and Applied Economics from the University of Alaska. A summary of my professional and educational background, including a list of my testimonies filed before regulatory commissions, is included as Exhibit JEN-1.

Q. Have you testified before any regulatory authorities?

A. Yes, I have. A list of regulatory proceedings in which I have filed expert testimony is provided in Exhibit JEN-1.

II. Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my Direct Testimony is to provide an overview of regulatory ratemaking reform policies in support of the Company's request for new ratemaking mechanisms. Specifically, my testimony addresses NorthWestern's proposals for regulatory reform through ratemaking mechanisms broadly used across the industry that are designed to better align the interests of customers and the Company, consistent with fundamental regulatory objectives and ratemaking principles.

Q. How is your testimony organized?

A. The remainder of my Direct Testimony is organized as follows:

- Section III – Summarizes the Company's request and need for regulatory reform in this proceeding, provides an overview of traditional regulation, and explains how the current utility operating environment departs from the environment that worked under traditional regulation.
- Section IV – Summarizes the trend in ratemaking mechanisms employed by utilities in other jurisdictions and compares Montana's regulatory environment to the other U.S. regulatory jurisdictions;
- Section V – Explains universal ratemaking principles and how the Company's proposals are consistent with universal ratemaking principles and with mechanisms in place at other utilities across the U.S.; and
- Section VI – Summarizes my conclusions and recommendation.

III. Overview of NorthWestern's Request and the Need to Re-Examine Ratemaking Treatment

Q. Please summarize the Company's requests for regulatory reform in this proceeding.

A. As explained in the testimony of Company witness Cynthia S. Fang, the Company is proposing several regulatory reforms to mitigate regulatory lag. Specifically, the Company requests approval of alternative ratemaking treatment for certain reliability and critical infrastructure investments, including:

1. Enhanced Wildfire Mitigation Plan Rider: NorthWestern seeks approval for an Enhanced Wildfire Mitigation Plan Rider and associated projected five-year capital costs and expenses for the years 2024 through 2028. The proposal includes annual filings that would (1) adjust rates to reflect the five-year annual incremental electric revenue requirement for the program, (2) report on activities from the prior calendar year, and (3) provide updates on activities expected for the upcoming calendar year.
2. Business Technology Maintenance Cost Escalation Rider : The Company requests approval of a new rate mechanism that would recover certain Business Technology ("BT") and Cyber Security expenses on an annual inflation-adjusted basis indexed to the GDP deflator index. NorthWestern proposes to re-examine the trends in BT costs in its next regulatory rate review to determine whether the inflation-adjusted increase remains warranted in future recovery of these costs.
3. Reliability Rider: The Company requests approval of a new rate mechanism to track and recover capital costs and expenses associated with critical, new reliability investments on an interim basis between regulatory rate reviews, subject to refund, as determined in a prudence review in a future rate review. The Reliability Rider would apply to investments with the specific purpose of maintaining and/or improving safe and reliable electric service.

Additionally, NorthWestern proposes changes to two of its current regulatory mechanisms. As Ms. Fang explains, the Company proposes adjustments to its Power Costs and Credits Adjustment Mechanism ("PCCAM") to better capture evolving market conditions. It also proposes to redesign NorthWestern's Fixed Cost Recovery Mechanism ("FCRM") pilot approved in Docket No. 2018.02.12.

Q. Please summarize your conclusions regarding the Company's proposals and how they would benefit both customers and the Company.

A. As discussed throughout my testimony, the Company's proposals are driven by the need to mitigate regulatory lag resulting from several factors that, in aggregate, reduce revenues just as cash flow is needed to fund the capital investments necessary to provide safe and reliable service. Those factors – flat or declining use per customer and continuing non-revenue producing capital investments – have affected utilities across the United States. Other utilities and other regulatory commissions have recognized that, in the current environment, traditional cost of service regulation is insufficient to provide the timely recovery of costs needed to ensure customers are served by financially sound utility companies. They have addressed those concerns by implementing "alternative" ratemaking structures with similar objectives of those proposed by the Company.

Other utility companies, regulatory commissions, and the financial community have recognized that traditional regulation through the periodic rate review framework no longer adequately addresses the needs of customers and the utility companies, and that some form of regulatory reform is required to align the interests of multiple stakeholders. As with the Company's proposed structures, the regulatory mechanisms put in place at other utilities address the dilution in cash flow that inevitably weakens their financial profile, ultimately to the detriment of customers. And like the regulatory mechanisms in place at other utilities, the Company's proposed mechanisms would mitigate (but not eliminate) the need for more frequent rate proceedings, to the benefit of customers.

Q. Please provide an overview of the ratemaking framework that has been applied under traditional regulation.

A. Under traditional regulation, utilities are granted an exclusive service territory in exchange for the obligation to provide utility service to customers within that territory, and to be subject to rate regulation, including a regulated rate of return. As enshrined by the U.S. Supreme Court, a regulated utility's rates must provide a reasonable opportunity (which is not a guarantee) for a utility to earn a fair rate of return that: (1) is comparable to returns investors expect to earn on other investments of similar risk; (2) assures confidence in the company's financial integrity;

and (3) is adequate to maintain and support the company's credit and to attract capital.[1]

Cost of service regulation largely arises from the essential nature of utility services, in which unit costs historically decreased as output rose. Because of their declining cost structures, utility services in a specific market were thought to be more efficiently provided by a single firm than by multiple firms. Although they may serve different sectors (*e.g.*, electricity, natural gas, water, wastewater), utilities are capital-intensive enterprises, whose investments are long-lived, essentially irreversible, and represent high "sunk" costs.

Under traditional regulation, the process of setting just and reasonable rates utilizes the concept of a twelve-month "test year" period to determine revenue requirements and billing determinants. The rates approved in the rate proceeding are then fixed until the next rate review. The test year was traditionally a backward-looking measurement[2] of rate base, expenses, and revenues used to determine a utility's cost to serve customers under the expectation that the relationship between these elements will continue during the rate year and beyond.

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[1] *See, Bluefield Water Works and Improvement Co. v. Public Service Comm'n*, 262 U.S. 679, 692 (1923); *Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944).

[2] Certain *pro forma* adjustments are often allowed to reflect more current known and measurable data or to remove the effects of unusual events.

In other words, historical costs are used to set future rates, which results in a lag between the time funds are expended and the time rates recover those costs. Because utility costs are largely fixed in nature,[3] but recovered through volumetric rates, if sales are higher than anticipated at the time rates were set, the utility's profit will be higher, all else equal. Under traditional regulation, the utility retains the excess revenues between rate reviews to fund additional investment. However, if sales are lower than anticipated, revenues will be lower (all else equal), and the utility may not have sufficient earnings to cover its fixed costs and invest in the capital necessary to provide safe and reliable service. Therefore, under traditional regulation, regulatory lag is a significant challenge for utilities in situations in which costs are rising faster than sales, resulting in earnings attrition.

Q. Why is it important that regulation provide utilities with a reasonable opportunity to earn a fair return?

A. The ratemaking process is based on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have a reasonable opportunity to recover the return of, and the market-required return on, prudently invested capital, as well as prudently incurred associated expenses. Because utilities have an

[3] That is, the majority of a utility's costs do not vary with output.

obligation to provide safe and reliable service to all customers at all times, utilities require sufficient cash flow and ongoing access to investor-supplied capital to fund the significant capital expenditures needed to maintain, expand, and modernize existing infrastructure.

As the National Regulatory Research Institute astutely observes, "regulation recognizes that financially healthy utilities are necessary for the long-term economic welfare of customers."[4] Company witness Crystal D. Lail explains that utilities with a weaker financial profile will likely have a higher cost of capital and may not have efficient access to capital on reasonable terms when and as needed to finance investments that provide safe and reliable service. The benefit of a solid financial profile, therefore, aligns with customers' interests of receiving safe and reliable service. Therefore, it is critical that regulation provide a reasonable opportunity to earn an adequate return that supports the financial integrity of the utility.

Q. How does the current environment differ from the circumstances in which traditional regulation enabled utilities to provide safe and reliable service while maintaining their financial strength?

A. Historically, the utility industry was characterized by increasing sales and customer growth, and investments were largely spent on plant to meet

[4] *Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives*, National Regulatory Research Institute, at iv (April 2014).

sales and customer growth (*i.e.*, investments were revenue producing). Upward pressures on utility costs, therefore, could be addressed in the short-term (*i.e.,* between rate reviews) through customer and sales growth and cost management. However, that environment has changed. Electric and natural gas sales volumes per customer have been flat or declining for about the last two decades, driven in part by conservation efforts (*see, e.g.*, Figures 2 and 3 below). Yet, the need to maintain service reliability and address public policy objectives has continued, or even increased, thus putting increased cost pressure on utilities. Many of the investments required to maintain system integrity and reliability do not generate incremental revenue through additional volume growth. These non-revenue producing investments include investments for infrastructure replacement, grid modernization, resiliency and system hardening, and environmental compliance expenditures. As the U.S. Energy Information Administration ("EIA") noted in a recent article:

> Distribution spending has outpaced growth in both the number of electric customers and in retail electricity sales because much of the increased distribution spending in the last 20 years has been on projects that are not directly related to customer growth or increased sales. These investments are not driven by an increase in the number of customers or sales. These projects include replacing aging equipment, modernizing and upgrading maintenance and billing technology, and fortifying distribution structures against weather-related damage.[5]

[5] U.S. Energy Information Administration, "Major Utilities' spending on the electric distribution system continues to increase," *Today in Energy*, May 27, 2021. https://www.eia.gov/todayinenergy/detail.php?id=48136.

Furthermore, states are placing more emphasis on energy efficiency and conservation programs, which have contributed to flat or declining sales. Unlike earlier periods when volume growth enabled the timely return of and on incremental non-revenue producing investments, the current environment is more challenging. As a result, utilities cannot continue to rely on load growth or improved profitability generated through reduced operating and maintenance ("O&M") costs to fund their infrastructure replacements, and to sustain their financial integrity as those investments are being undertaken. That condition presents considerable financial challenges for utilities with a continuing need to invest capital in non-revenue producing infrastructure. Earnings pressure becomes even more acute as the rate of capital expenditures or inflation accelerates. The current historically high inflation rate presents a significant challenge for utilities, particularly those that that lack regulatory support to align rates with costs affected by accelerated inflation beyond their control.

The ability to efficiently acquire the capital needed to fund the growing level of infrastructure investments is dependent on the ability to recover that investment in a timely manner. As noted by the American Gas Association:

> Timely cost recovery of prudently incurred safety and reliability investments is of utmost importance to the financial stability of natural gas utilities. Because traditional ratemaking allows recovery of infrastructure investments only following approval in a rate case, there is often a multi-year delay before the recovery of such investments begins.

> Investments that are recovered long after they are incurred cause the utility to bear carrying costs without the opportunity to recover these prudent expenditures. Credit agencies criticize companies with lag in the recovery of their costs and assign a lower credit rating to such utilities that ultimately translates into higher rates for customers. The only alternative is to file a rate case each year, which is a costly activity that also leads to higher rates for customers.[6]

These concepts hold true for electric utilities as well. Increasing capital investments, together with reduced sales per customer, create a circumstance in which each dollar of invested assets produces fewer dollars of revenue. When that occurs, the ability to fund capital investments through revenue increases will be limited and the utility will likely experience earnings attrition. As the American Gas Association noted, absent other solutions, the only alternative to funding those investments is more frequent rate reviews, which are costly and time consuming.

Q. Turning to the Company's proposals, why are they now needed?

A. The requests are necessary because, as Ms. Lail explains, ensuring the Company has a reasonable opportunity to achieve its authorized return is critically important to both the Company and its customers. The proposals would mitigate the effect of (1) reduced use per customer on the recovery of revenues authorized by the Commission; (2) non-revenue producing capital investments, including those proposed in its Enhanced Wildfire

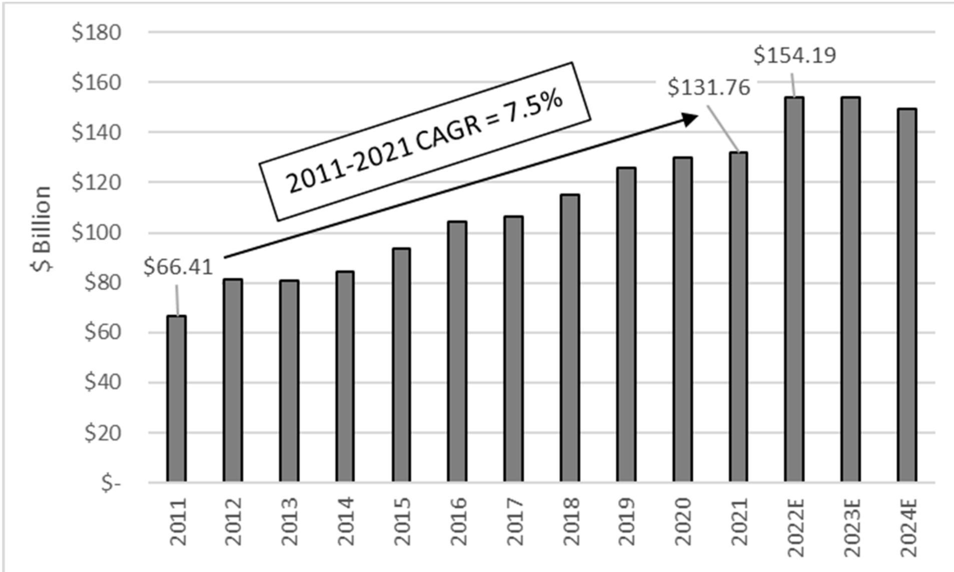
[6] American Gas Association, Infrastructure Cost Recovery Update, June 2012, at 2.

Mitigation Plan Rider; and (3) rising costs associated with its BT and Cyber Security maintenance expenses. Further the Reliability Rider would enable timely recovery of critical reliability investments. Without the requested regulatory reforms, NorthWestern will need to seek more frequent rate relief to meet its obligation to provide safe and reliable service to customers and maintain its financial integrity.

Q. Earlier you observed that the current utility environment has experienced increased capital spending combined with declining use per customer, inhibiting the effectiveness of the traditional regulatory framework. Please more fully explain the trend in these metrics over recent years.

A. Turning first to capital expenditures, according to data from Regulatory Research Associates ("RRA"), utility capital expenditures at 47 electric and natural gas utilities increased at a compound annual growth rate ("CAGR") of 7.5 percent between 2011 and 2021, as shown in Figure 1 below. RRA projects capital expenditures to increase 17 percent in 2022 over 2021 to $154.2 billion.

Figure 1: Utility Capital Expenditures (2011-2024E)[7]



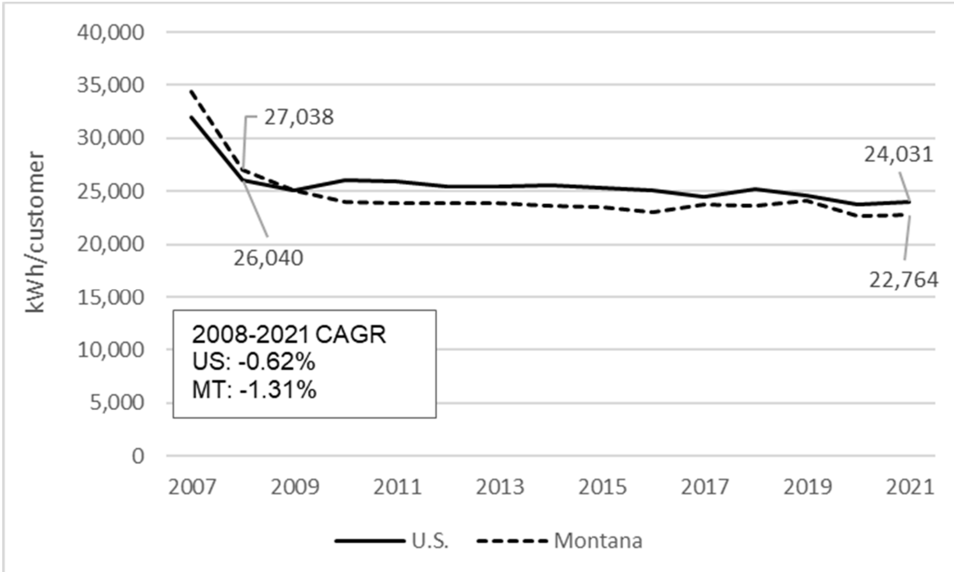
During this same period, NorthWestern's total assets increased by 7.61 percent per year on a compound annual growth basis,[8] highly consistent with the trend for the utility sector shown in Figure 1 above.

With respect to use per customer, as Figure 2 below illustrates, electricity use per customer has been relatively flat since 2008 in both the U.S. and Montana.

[7] Source: S&P Global Regulatory Research Associates, *Financial Focus: Utility Capital Expenditures Update*, April 11, 2022.

[8] Source: NorthWestern Energy Annual Reports to the Montana Public Service Commission, Schedule 18.

Figure 2: Electricity Use Per Customer[9]

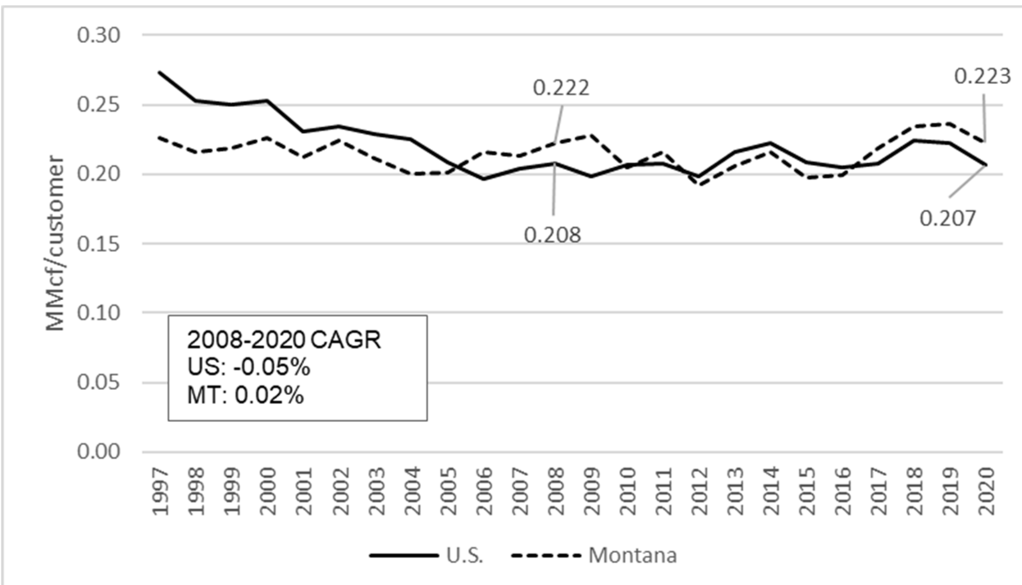


According to data from the EIA, retail sales of electricity for all sectors in the U.S. and Montana grew at a compound annual rate of 0.12 percent and -0.21 percent, respectively, between 2008 and 2021. However, the number of customers grew faster than sales in kilowatt-hours ("kWh") resulting in a decline in load per customer. On a per-customer basis, electricity sales declined at a compound annual rate of 0.62 percent per year and 1.31 percent per year in the U.S. and Montana, respectively, between 2008 and 2021 (*see* Figure 2 above). These statistics demonstrate that customers have been using less electricity over the last 13 years.

[9] Source: U.S. Energy Information Administration, Form EIA-861M.

Similarly, between 2008 and 2020, natural gas consumption[10] per customer in the U.S. and Montana was flat on a compound annual growth basis. Natural gas use per customer grew at a compound annual rate of -0.05 percent per year, and 0.02 percent per year in the U.S. and Montana, respectively (*see* Figure 3 below).

Figure 3: Natural Gas Use per Customer[11]



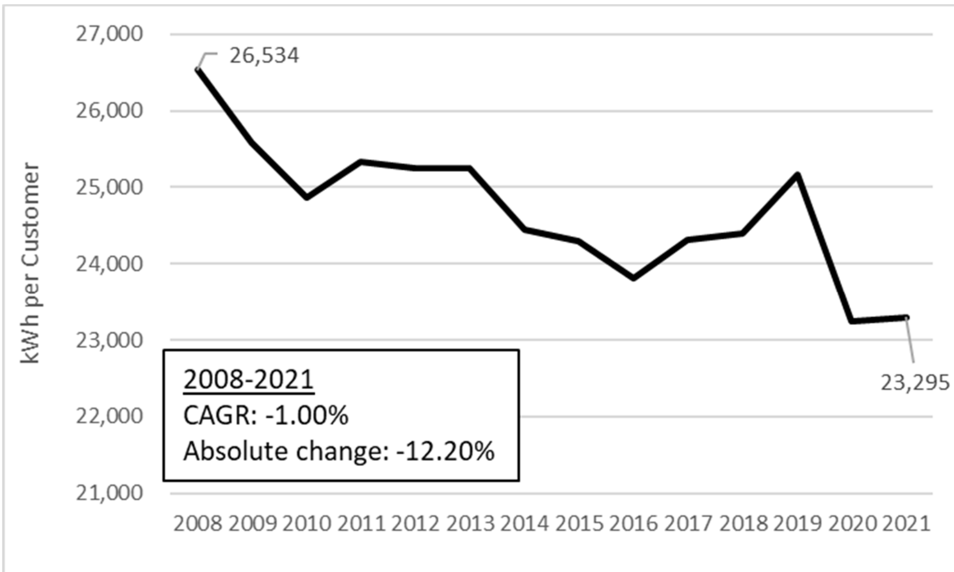
Q. Has the Company also experienced flat or declining sales per customer in Montana?

[10] Residential, Commercial, and Industrial consumption only; excludes transportation and natural gas used by electric power customers. 2021 customer count data was not yet available from the EIA at the time of preparing this testimony.

[11] Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use, Number of Natural Gas Consumers. Customer count data begins in 1997.

A. Yes. Figures 4 and 5 below graph the trend in the Company's residential, commercial, and industrial class combined use per customer for its electric and natural gas operations, respectively.

Figure 4: NorthWestern Montana Electric Use Per Customer (2008-2021)[12]



Between 2008 and 2021, the Company's customer growth in its residential class, commercial, and industrial classes combined significantly outpaced sales growth in those classes, resulting in a decline in use per customer of 12.20 percent over that period (a compound annual growth rate of -1.00 percent per year). Residential use per customer was relatively flat between 2008 and 2021, increasing at a compound annual growth rate of only 0.14 percent per year, whereas use per customer in the commercial

[12] Source: NorthWestern Energy Annual Electric Utility Reports to the Montana Public Service Commission, Schedule 36. Residential, Commercial, and Industrial classes combined.

and industrial classes declined at a compound annual rate of 1.60 percent per year[13]

The Company's natural gas consumption per customer for its residential, commercial, and industrial firm classes combined declined 8.79 percent between 2008 and 2021, or -0.71 percent per year on a compound growth basis (*see* Figure 5 below).[14] Use per customer declined at a compound annual rate of 0.85 percent, 0.32 percent, and 1.03 percent per year in the residential, commercial, and industrial firm rate classes, respectively,during this period.

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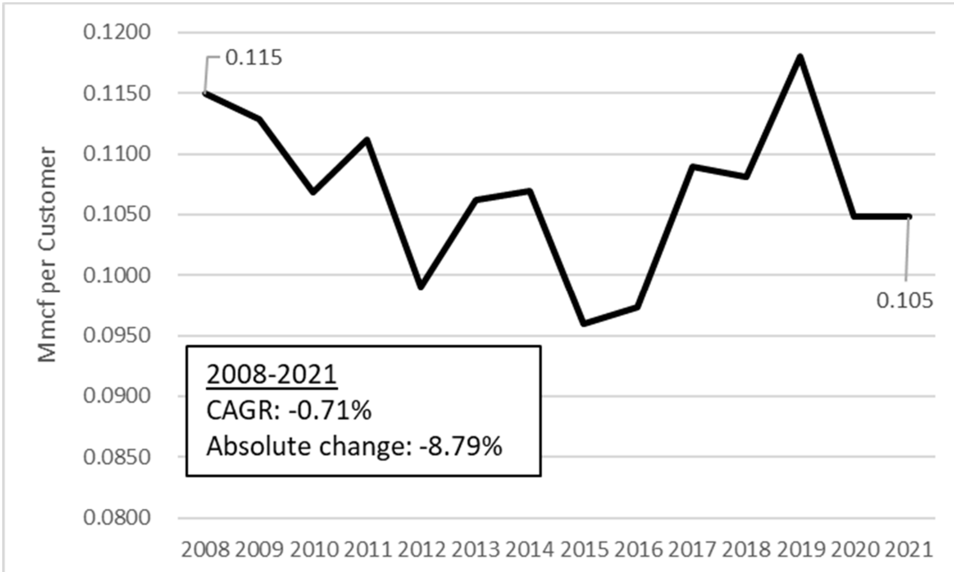
[13] Source: NorthWestern Energy Annual Electric Utility Reports to the Montana Public Service Commission, Schedule 36, Residential, Commercial, and Industrial classes combined.

[14] Source: NorthWestern Energy Annual Gas Utility Reports to the Montana Public Service Commission, Schedule 35, Residential, Commercial, and Industrial Firm classes.

Figure 5: NorthWestern Montana Natural Gas Use Per Customer (2008-2021)[15]



Q. How has increasing capital expenditures combined with declining use per customer affected revenues generated from utility assets?

A. The ability of a company's assets to produce revenue is measured by the Asset Turnover ratio.[16] The Asset Turnover ratio is an efficiency ratio calculated as the ratio of operating revenues to average total assets. A decrease in the Asset Turnover ratio occurs when there is an increase in assets with a less than one-to-one increase in revenues. That is, a declining Asset Turnover ratio is an indication of the situation noted earlier

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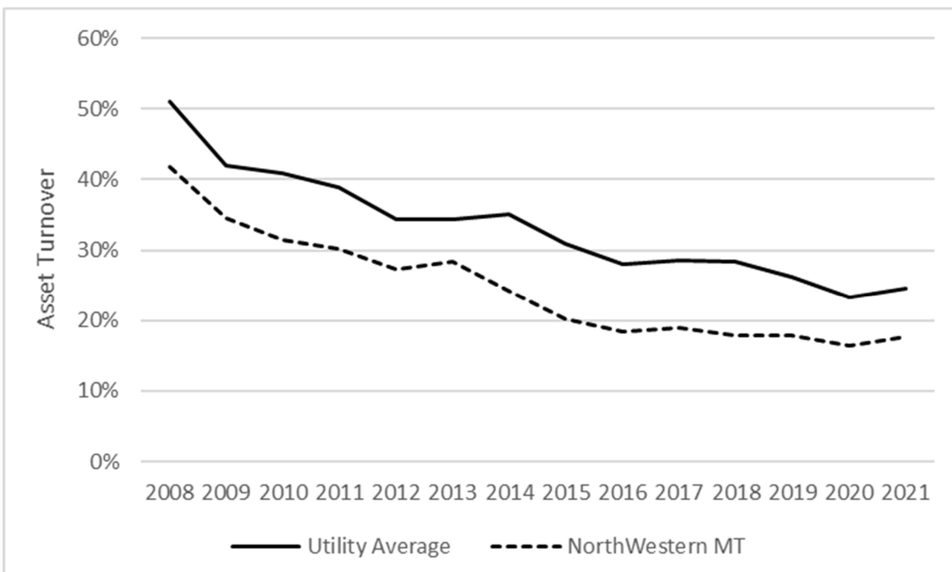
15 Source: NorthWestern Energy Annual Electric Utility Reports to the Montana Public Service Commission, Schedule 35. Residential, Commercial, and Industrial Firm classes.

16 *See e.g.*, https://www.investopedia.com/terms/a/assetturnover.asp.

in which each dollar of invested assets produces fewer dollars of revenue (*i.e.*, assets are non-revenue producing).

As Figure 6 below shows, NorthWestern's Asset Turnover ratio declined from 2008 to 2021, consistent with the trend in the utility industry. Whereas the Asset Turnover ratio for investor-owned electric and natural gas utilities declined approximately 51.73 percent on average during that period,[17] the Company's Asset Turnover ratio declined approximately 57.95 percent.

Figure 6: Asset Turnover Ratio, 2008-2021[18]



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17 Average of 62 electric and natural gas utility companies.

18 Sources: S&P Capital IQ Pro; NorthWestern Energy Electric and Natural Gas Utility Annual Reports to the Montana Public Service Commission (2008-2021), Schedules 8 and 18.

Q. What are your conclusions regarding the current utility operating environment?

A. As shown in Figures 1 to 6 above, electricity and natural gas sales per customer have not kept pace with capital investments; as a result, the ability of utility assets to produce revenue has fallen. The Company has not been immune to these trends. As noted earlier, the effectiveness of traditional ratemaking is likely impeded in this operating environment, leading to earnings attrition.

Q. Please explain the concept of attrition.

A. Earnings attrition is the failure of a utility have a reasonable opportunity to earn its authorized return as a result of a structural breakdown in the relationship between rate base, expenses, and revenues that is captured in rates. The factors that contribute to earnings attrition generally involve a combination of industry-, utility-, and regulatory-specific circumstances. Ratemaking policies and the regulatory environment can contribute to, or alleviate, earnings attrition.

As explained by the Washington D.C. Public Service Commission ("DCPSC"):

> [Attrition is a]…phenomenon in utility regulation which is characterized by growth in plant investment, operating expenses, senior capital costs, or a combination of these costs that is more rapid than the relative growth of a utility's

> revenues, and which thereby results in a shortfall in the utility's rate of return on investment, rate return on equity, or both.[19]

When there is a disconnect between the rate base-expenses-revenues relationship recovered through rates and the relationship that occurs during the rate year(s),[20] it reflects a circumstance in which the relationship among these three components that existed during the test period does not continue in the rate year. As indicated by the DCPSC, attrition can be categorized into three primary forms: (1) rate base attrition, (2) expense attrition, and (3) capital cost attrition.

- Rate Base Attrition results from circumstances in which a utility's revenues do not keep pace with increases in a utility's rate base. It is typically caused by the need to replace older plant with new, more expensive plant, or by adding non-revenue producing plant that does not produce incremental revenue.
- Expense Attrition results from circumstances in which a utility's revenues do not keep pace with increases in a utility's expenses. Expense attrition can occur when there is an extraordinary growth in specific expense categories (*e.g.*, insurance, fuel costs, property taxes, or pensions).
- Capital Cost Attrition results from circumstances in which a utility's revenues do not keep pace with increases in a utility's capital costs

[19] Case No. 712, Order No. 8204, District of Columbia Public Service Commission, April 3, 1985.

[20] The rate year(s) is the year(s) in which the costs in a test year are recovered from customers in rates.

(*e.g.*, costs of debt and equity). In other words, the costs of capital in the rate year are higher than the embedded costs incorporated in the authorized rate of return. Capital cost attrition most commonly occurs during periods of increasing inflation and interest rates.

Q. How do ratemaking policies and the regulatory environment affect attrition?

A. Because utility revenues are set by the regulator, ratemaking policies and practices can contribute to, or alleviate, attrition. As noted earlier, regulatory lag is a significant driver of earnings attrition, particularly under traditional regulation. Ratemaking policies regarding (1) the timing of test year data and (2) the timeliness of cost recovery between rate reviews are two primary avenues in which regulators can influence attrition.

Ratemaking policies regarding the test year methodology, *pro forma* adjustment practices, and the length of time between the end of the test year and the implementation of new rates can contribute to or alleviate regulatory lag. Shortening the timing difference between test year data and the date when rates go into effect improves the likelihood that the rate base-expenses-revenues relationship during the test year more closely aligns with the relationship during the rate year(s). Similarly, allowing a utility to adjust rates between rate reviews is another avenue through which regulators can mitigate regulatory lag and earnings attrition.

Examples of common mechanisms used to adjust rates between rate reviews include: (1) expense cost tracking mechanisms, (2) capital cost tracking mechanisms, (3) multi-year rate plans with attrition relief adjustments, (4) revenue stabilization mechanisms (*e.g.*, revenue decoupling and formula rate plans), and (5) performance-based rates. I discuss these ratemaking mechanisms and regulatory frameworks in more detail in Section IV.

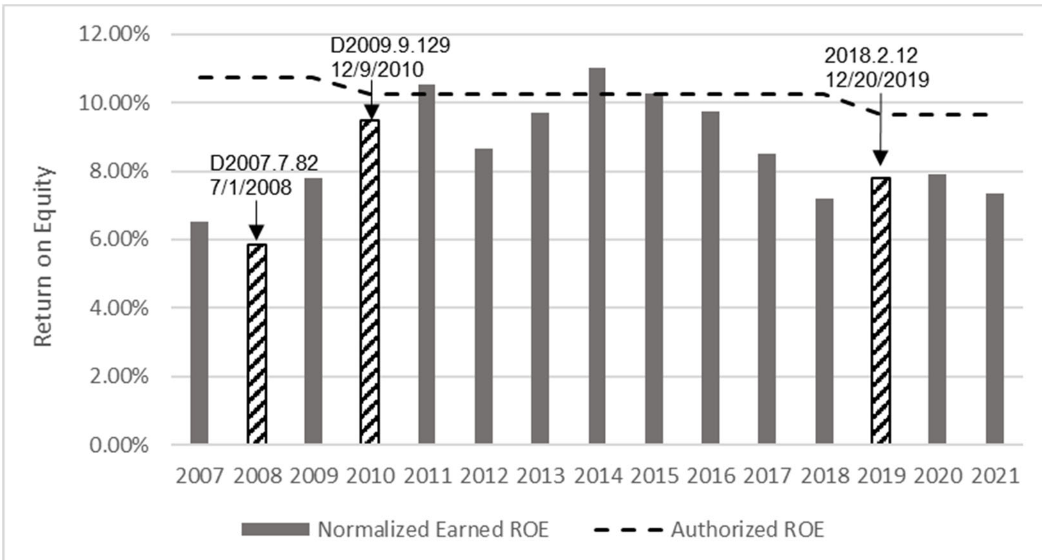
Q. Have you analyzed the Company's performance to determine whether it may be experiencing earnings attrition?

A. Yes, I have. I reviewed the Company's historical earned return on equity ("ROE") versus its authorized ROE, historical non-fuel O&M expense growth, and its Asset Turnover ratio.

Q. Please describe your analysis regarding NorthWestern's historical earned vs. authorized ROE.

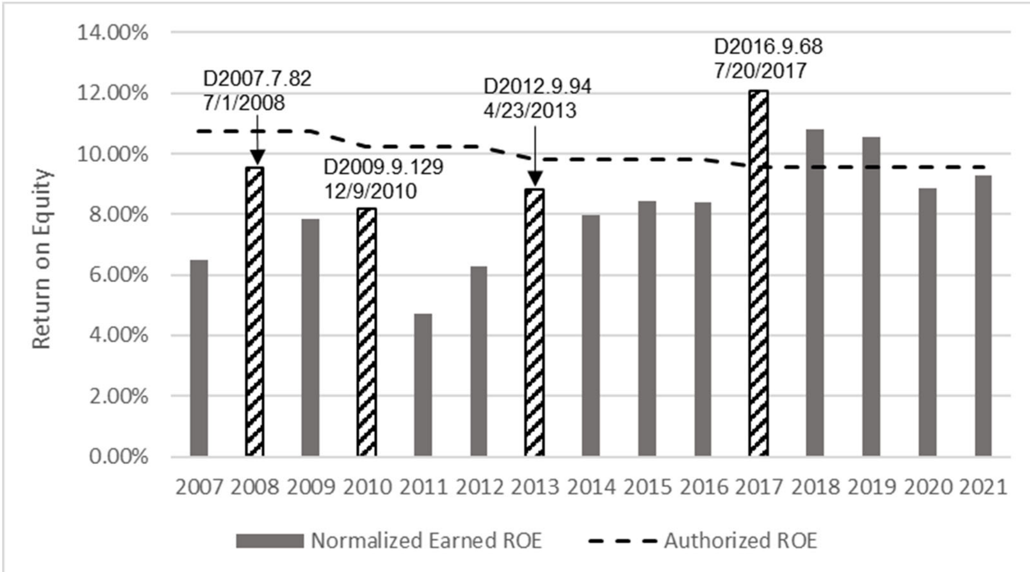
A. I reviewed the Company's electric and natural gas utility annual reports to the Commission between 2007 and 2021. I chose this period to assess the sufficiency of NorthWestern's rates to sustain the Company's ability to earn its authorized ROE between rate reviews over several cycles. Figures 7 and 8 below show that the Company has underearned its authorized ROE in twelve of the last fifteen years for both its electric and natural gas operations. Figures 7 and 8 below also show that any increase in earnings after a rate review has often been insufficient and/or short lived.

Figure 7: Electric Earned vs. Authorized ROE (2007-2021)[21]



21 Source: Electric and Natural Gas Utility Annual Reports to the Montana Public Service Commission, 2007-2021, Schedule 27, "Adjusted Rate of Return on Average Equity". 2010 and 2011 earned ROE include Lost Revenue Adjustment Mechansim ("LRAM") revenue. Note: The Company's rate review decided in 2008 included a black box settlement in which the authorized ROE was not determined. Authorized ROE reflects the year in which the Commission order was issued.

Figure 8: Natural Gas Earned vs. Authorized ROE (2007-2021)[22]



Q. What has been the trend in the Company's non-fuel and purchased power supply O&M expenses?

A. From 2008 to 2021, NorthWestern's combined non-fuel, power supply, and natural gas supply O&M ("Non-Fuel O&M") expenses[23] for its Montana electric and natural gas operations increased at a compound annual rate of 4.71 percent per year.[24] To assess whether the increase in

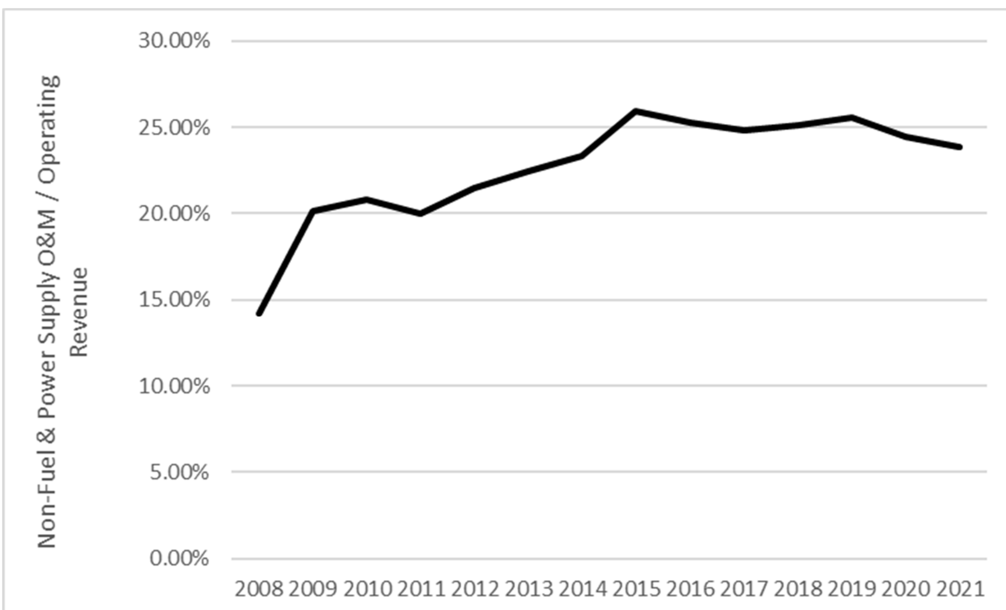
[22] Source: Electric and Natural Gas Utility Annual Reports to the Montana Public Service Commission, 2007-2021, Schedule 27, "Adjusted Rate of Return on Average Equity". Note: The Company's rate review decided in 2008 included a black box settlement in which the authorized ROE was not determined. Authorized ROE reflects the year in which the Commission order was issued.

[23] Because utilities typically are able to recover fuel, purchased power, and natural gas commodity costs between rate reviews, non-fuel O&M more closely reflects expenses that are generally recovered through base rates.

[24] Source: NorthWestern Energy Electric and Natural Gas Utility Annual Reports to the Montana Public Service Commission (2008-2021), Schedule 10. Combined electric and gas non- fuel, power supply, and gas supply O&M expenses.

Non-Fuel O&M expenses may be contributing to earnings attrition, I calculated Non-Fuel O&M expenses as a percent of operating revenues to determine whether the Company's operating revenues have kept pace with Non-Fuel O&M expenses. As shown in Figure 9 below, Non-Fuel O&M expenses as a percent of operating revenue increased from 2008-2015, and has been relatively stable since. This could be an indication that expense attrition has been a factor for NorthWestern. As noted earlier, however, containing expense growth is likely to be more challenging in the near term given the current historic levels of inflation.

Figure 9: NorthWestern Montana Non-Fuel O&M Expenses as a Percent of Operating Revenues



Q. What has been the trend in the Company's Asset Turnover ratio?

A. As noted earlier, the Company's Asset Turnover ratio for its Montana operations declined by 57.95 percent between 2008 and 2021. This decline was driven by a 7.42 percent compound annual increase in the Company's average total assets relative to only a 0.58 percent compound annual increase in total company operating revenues over that same period.[25] In other words, the Company's assets are not producing commensurate increases in revenues. This suggests the Company may be experiencing rate base attrition.

Q. What are your conclusions regarding the effectiveness of traditional ratemaking in the current environment for electric and natural gas utilities, including the Company?

A. The combination of (1) flat or declining sales and (2) increased pressure from non-revenue producing investments has resulted in a significant decline in the efficiency of utility assets to produce revenue. NorthWestern has not been immune to these trends; since 2008, (1) its use per customer has been flat or declining, (2) the efficiency of its assets to produce revenue has declined significantly since 2008, and (3) its Non-Fuel O&M expenses have increased. Although its Non-Fuel O&M expenses as a percent of operating revenue has been relatively stable over the last six years, containing expense growth may prove more

[25] Source: NorthWestern Energy Annual Report to the Montana Public Service Commission (2008-2021), Schedules 8 and 18.

challenging in the future given the current historically high inflation environment.

In response, many regulatory commissions have adopted "alternative" ratemaking mechanisms and frameworks to mitigate (but not necessarily eliminate) regulatory lag and earnings erosion. However, as discussed below, the Commission's adoption of constructive and more timely cost recovery mechanisms has lagged behind other regulatory jurisdictions, which exposes the Company to higher risk compared to utilities that operate in more constructive regulatory environments that allow for timelier cost recovery.

IV. Trends in Utility Ratemaking Regulation

Q. What is alternative regulation?

A. Alternative regulation is a term applied to a broad range of regulatory frameworks and mechanisms in which cost recovery and rate adjustments occur outside of the traditional regulatory framework where rates are adjusted through periodic general rate reviews.[26] Alternative ratemaking mechanisms fall along a spectrum from incremental reform to comprehensive reform. Mechanisms that represent incremental reform apply to a single component, such as fuel and purchased power cost recovery mechanisms or a future test year. Mechanisms that represent

[26] *See, e.g.*, S&P Global Market Intelligence, RRA Regulatory Focus, *Alternative Ratemaking Plans in the U.S.*, at 2 (April 16, 2020).

comprehensive reform include ratemaking structures that address the overall revenue requirement such as revenue decoupling, multi-year rate plans, formula rate plans, and performance-based rate plans. As discussed below, while termed “alternative”, these mechanisms are widely adopted and their use has continued to increase in the industry.

The major categories of alternative ratemaking mechanisms are summarized below. Although alternative ratemaking mechanisms can be categorized into broad categories, it is important to note that the details and mechanics of each mechanism are tailored to the unique circumstances of each utility and the regulatory jurisdiction in which it operates.

- Infrastructure Surcharges: Infrastructure surcharges allow some cost recovery prior to the completion of a facility with the objective of mitigating rate shock that would occur when the facility is added to rate base. Examples: Allowance for Funds During Construction (“AFUDC”) and including Construction Work in Progress (“CWIP”) in rate base.
- Future Test Year: Test year data used to determine revenues and costs that is partially or fully forecasted, mitigating the problem of stale historical test year data that may poorly predict future conditions.

- Cost Tracking Mechanisms: Expense or capital cost tracking mechanisms (also known as adjustment clauses) that allow utilities to recover specific costs from customers outside of a general rate review. Examples: fuel and purchased power mechanisms, conservation program expense mechanisms, capital cost tracking mechanisms, etc.
- Revenue Decoupling: A revenue stabilization mechanism that reconciles actual revenues to a revenue target approved in the last rate review. Revenue decoupling mechanisms decouple the link between utility sales and profits and therefore remove a utility's incentive to increase sales and discourage utility-sponsored energy efficiency programs. Revenue decoupling improves a utility's opportunity to recover its fixed costs by addressing one or more drivers of lower sales that are generally beyond a utility's control, specifically weather, conservation, or economic drivers. Partial, or "limited", decoupling mechanisms address one or two drivers (*e.g.*, lost revenue adjustment mechanisms, weather normalization adjustment clauses) and full revenue decoupling addresses all three drivers.
- Multi-Year Rate Plan: Rate plans that true up the utility's actual cost of service once over a multi-year period, with rate adjustments tied to changes in external factors occurring in the interim. Annual

rate adjustments may include a “stairstep”[27] or “indexed”[28] approach to rate increases associated with external factors (sometimes referred to as an “attrition relief mechanism”). Additionally, multi-year rate plans may include other components such as earning sharing mechanisms, performance incentives or penalties, and cost tracking mechanisms.

- <u>Formula Rate Plan:[29]</u> A comprehensive revenue stabilization mechanism in which a utility’s revenues are compared to its cost of service through streamlined annual rate filings in which rates are adjusted if the actual earned ROE is outside a zone above and below an authorized target ROE. There are no rate adjustments if the earned ROE is within the authorized target zone.
- <u>Performance-Based Rates:</u> A multi-year rate plan that includes a price or revenue cap in which prices (or revenues) are indexed to a measure of inflation minus a measure of productivity. Performance-based rates often include performance incentive metrics that may reward or penalize a utility’s performance in order to safeguard service quality.

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[27] Discrete revenue adjustments at specific time intervals.

[28] Revenue or cost adjustments tied to an index, such as inflation or an industry benchmark.

[29] The formula rate plan framework generally applied at the retail level is not equivalent to the formula rate process used by the FERC.

Q. Please explain, generally, the trend in alternative regulation in the United States.

A. Alternative regulation has been implemented to supplement traditional regulation, with the primary objective of mitigating regulatory lag and earnings erosion. Cost recovery adjustment mechanisms initially arose from the need to address rapidly rising fuel costs during the early 1970s, when fuel prices climbed more rapidly than the utilities' ability to obtain rate recognition of the increased costs through the traditional rate review process. During that time, utility earnings were under considerable pressure, which prompted jurisdictions to allow more timely recovery of cost increases that were beyond the control of the utilities.[30]

As explained above, alternative regulation has been of increased interest in recent years due to rising and volatile utility costs, growth in non-revenue producing capital expenditures, and sluggish demand and sales growth, which, as noted earlier, puts pressure on traditional volume-based, cost-of-service ratemaking. More recently, states have also pursued certain public policy initiatives and have developed mechanisms to support and advance those policies. For utilities, alternative ratemaking mechanisms have been spurred by declining use per customer; reliability, environmental, and safety concerns; state-mandated energy efficiency programs; and a desire to improve utility performance.

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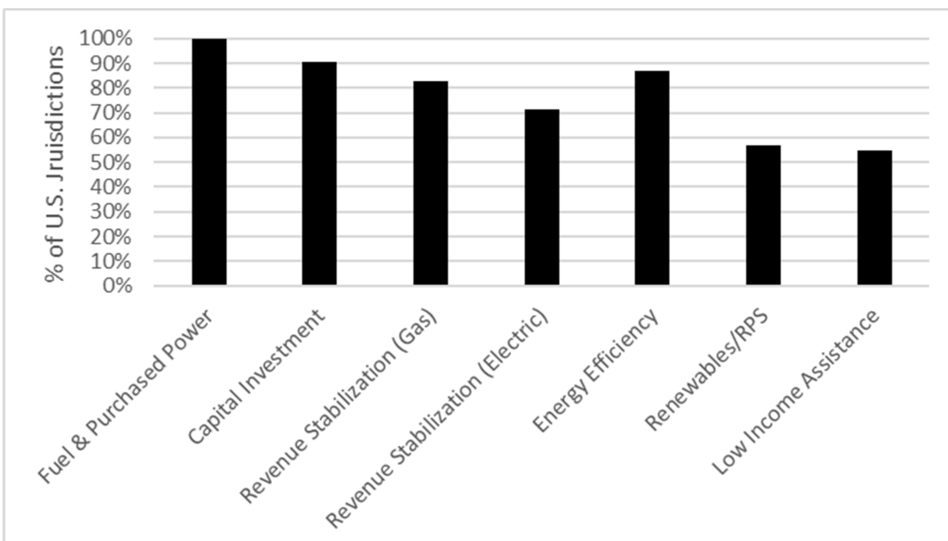
[30] Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview*, July 18, 2022, at 3.

Q. Are alternative ratemaking mechanisms common in the U.S.?

A. Yes, as shown in Exhibit JEN-2, alternative ratemaking mechanisms have been adopted in every U.S. regulatory jurisdiction, including Montana. Figure 10 below illustrates the percentage of regulatory jurisdictions that have approved various cost recovery and revenue stabilization mechanisms for at least one electric or natural gas utility.

Figure 10: Percentage of Regulatory Jurisdictions with Cost Recovery and Revenue Stabilization Mechanisms[31]



Q. Please summarize your understanding of the Commission's regulatory environment and current ratemaking practices.

A. Figure 11 below summarizes the Commission's current ratemaking practices and authorization of alternative ratemaking mechanisms.

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31 Exhibit JEN-2.

Figure 11: Montana PSC Regulatory Environment[32]

Ratemaking Practice and Alternative Ratemaking Mechanism	Commission Practice	Notes
Rate case timeframe	9 months	
Test Year Methodology	Historic	Known and measurable adjustments within 12 months beyond end of test period allowed
Rate Base Methodology	Average original cost	Known and measurable adjustments within 12 months beyond end of test period allowed
Interim Rates	Allowed, subject to refund	Interim rates historically not authorized until after intervenor testimony is filed
Infrastructure Surcharges	AFUDC included in rate base	
Expense cost tracking Mechanisms	Allowed: Fuel and Power Cost Tracking, Universal System Benefits Charge (conservation, and low-income weatherization and bill assistance); taxes and fees	PCCAMrecovers only 90% of fuel and non-QF purchased power costs compared to the amount in base rates; PCCAM Base Costs updates currently occur only in rate reviews
Capital cost tracking Mechanism	None	
Revenue Stabilization Mechanism	Allowed	Montana-Dakota Utilities Co. recovers lost revenues associated with its natural gas conservation program
Multi-Year Rate Plan	None	
Formula Rate Plan	None	
Performance Based Rate Plan	None	

Q. How do the Commission's regulatory and ratemaking practices compare to other regulatory jurisdictions?

32 Source: S&P Global Ratings Regulatory Research Associates; Company provided information.

A. Exhibits JEN-2 and JEN-3 compare the the 53 U.S. regulatory environments on the adoption of cost recovery and revenue stabilization mechanisms and rate case parameters. As explained below, Montana's public utilities do not have the same opportunity to avail themselves of regulatory structures that enable more timely cost recovery as do utilities that operate in other jurisdictions. This puts the Company and other Montana utilities at a disadvantage relative to utilities in other jurisdictions. Because utilities in other jurisdictions have a better opportunity to recover their prudently incurred capital investments and expenses in a more timely manner, those utilities are a more attractive investment than the Company, all else equal. In order to attract investment, NorthWestern's investors will require higher costs of capital, which are ultimately borne by customers.

Q. How do the Commission's test period and rate base practices compare to other regulatory jurisdictions?

A. The Commission uses an historic test year and average original cost to set rate base. This test year and rate base methodology combination contributes substantially to regulatory lag, particularly as rate base increases. As shown in Exhibit JEN-3, only 9 of 53 U.S. regulatory jurisdictions (approximately 17 percent) utilize an historic test year with an average rate base, whereas approximately 83 percent (*i.e.*, 44 of 53 jurisdictions) allow for year-end rate base or a partially or fully forecasted test year. In the case of forward test years specifically, 32 jurisdictions (approximately 60 percent) allow for partially or fully forecasted test years, either by commission practice or statutory authority. Additionally, although the Commission allows for interim rates, I understand that it has not historically authorized interim rates until after intervenor testimony is filed, reducing the effectiveness of interim rates.

NorthWestern's proposed Enhanced Wildfire Mitigation Plan Rider and Business Technology Mainteance Cost Escalation Rider would incorporate projected (*i.e.*, forward-looking) data for these costs in rates, which would incrementally improve the Company's comparability to other utilities that have a forward test year. Given the current historically high inflationary environment and the potential for expense attrition, allowing the use of forward-looking costs in these proposals is a modest and reasonable measure to provide NorthWestern more timely financial support that would enable it to provide these critical reliability programs to customers.

Q. As noted in Figure 11 above, the PCCAM approved by the Commission only recovers 90 percent of the non-QF[33] costs compared to the base amount approved in the most recent rate review. Is that common?

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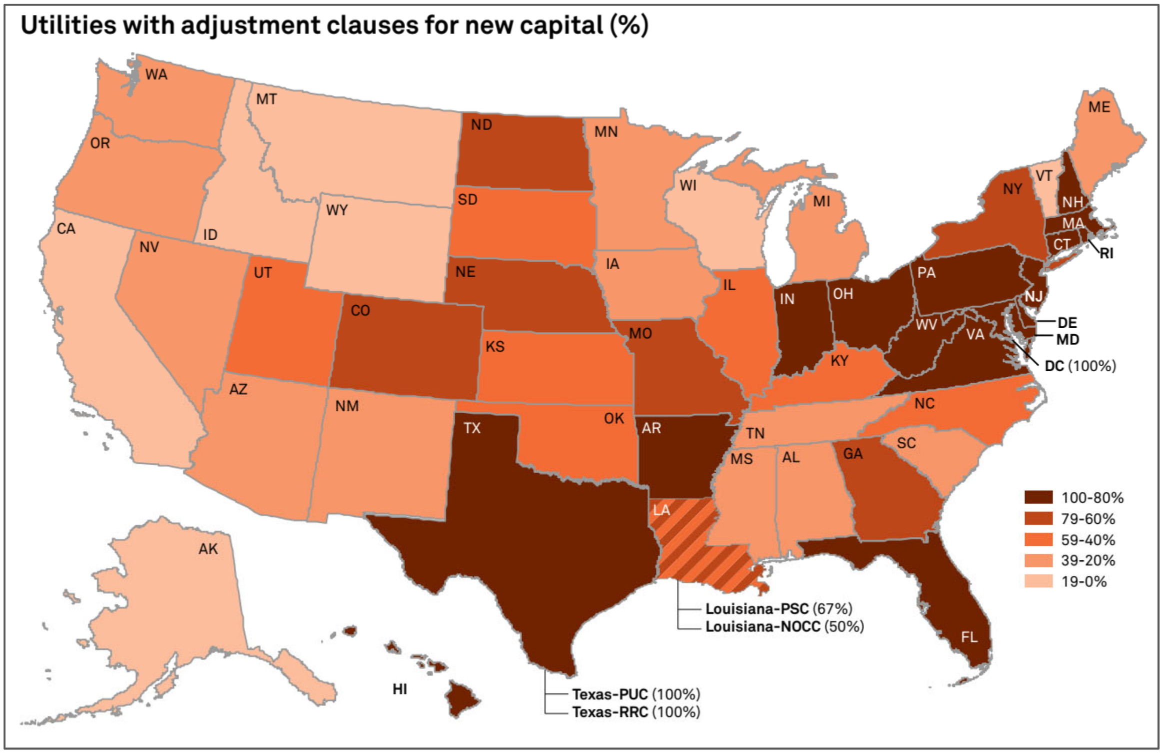
[33] Qualifying Facility.

A. No. The substantial majority of utilities are allowed to recover 100 percent of their actual fuel and purchased power costs. Outside of Montana's electric and natural gas utilities, of the more than 300 investor-owned utilities covered by RRA, only 26 electric utilities and 20 natural gas utilities have a fuel, power supply, or commodity cost mechanism that includes a sharing or incentive component. Sharing of off-system sales margins the utility and customers and hedging program incentives are also somewhat common; however, it remains that most utilities are allowed to recover 100 percent of their actual commodity and purchased power costs outside of base rates through an adjustment clause. The fact that the Company's cost recovery is limited to 90 percent of the non-QF fuel and purchased power costs in excess of the base amount approved in the last rate review exposes it to incremental risk relative to other utilities, particularly in an environment in which energy and commodity prices are increasing beyond their control.

Q. The Company's proposed Reliability Rider would allow more timely recovery of capital invested in specific reliability projects between rate reviews. Are capital cost recovery mechanisms commonly used by utilities?

A. Yes, capital cost recovery mechanisms are widely used by utilities in other jurisdictions. As Exhibit JEN-2 shows, 48 of 53 (or approximately 91 percent) regulatory jurisdictions have authorized a mechanism to recover capital costs outside base rates for at least one category of capital expenses for an electric or natural gas utility operating in that jurisdiction. Approving the requested Reliability Rider would render the Company more comparable to other utilities in terms of its opportunity to earn a fair return. For another perspective, Figure 12 below presents an illustration produced by RRA in November 2019 regarding the breadth of cost recovery mechanisms for new capital employed by utilities in other states. As Figure 12 below shows, Montana is in the bottom tier of only 7 states with less than 20 percent of utilities with a recovery mechanism to recover new capital costs between rate reviews, whereas 17 states/territories, including Texas, Florida, Arkansas, Indiana, Ohio, and West Virginia, have approved capital cost recovery mechanisms for at least 80 percent of public utilities.

Figure 12: Percentage of Utilities with New Capital Cost Recovery Mechanisms[34]



Q. The Commission has previously authorized fuel and purchased power cost recovery mechanisms, conservation program expense recovery mechanisms, and revenue decoupling. How does the Commission's approval of these forms of alternative regulation compare to other jurisdictions?

A. As Exhibit JEN-2 shows, 43 of 52[35] (approximately 83 percent) U.S. regulatory jurisdictions have authorized a revenue stabilization mechanism

[34] Source: Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview*, November 19, 2019, at 3.

[35] Texas natural gas utilities are regulated by the Texas Railroad Commission and the electric utilities are regulated by the Public Utility Commission of Texas. Therefore, there are 52 natural gas jurisdictions and 52 electric jurisdictions, but 53 total U.S. regulatory jurisdictions.

such as revenue decoupling for natural gas utilities, while 37 of 52 have authorized a revenue stabilization mechanism for electric utilities. With respect to expense cost recovery mechanisms, every jurisdiction (100 percent) allows utilities to recover the costs of fuel and purchased power or purchased gas commodity. Lastly, 46 of 53 jurisdictions have approved mechanisms to recover conservation and energy efficiency program expenses. In other words, the Commission's approval of these mechanisms is consistent with the majority of regulatory jurisdictions.

Q. What are your conclusions regarding the trend of alternative regulation adopted in regulatory jurisdictions?

A. As explained above, traditional regulation alone is not sufficient to enable utilities a reasonable opportunity to earn a fair return when non-revenue producing investments are increasing faster than sales growth. As the utility market and operating environment have changed, the adoption of alternative regulation has increased, indicating increased acceptance by regulators, stakeholders, and the financial community. However, given the Company's more limited access to these commonly-used ratemaking mechanisms, it has a lesser opportunity to achieve more timely cost recovery than do utilities in other jurisdictions, putting it at a relative disadvantage.

V. <u>NorthWestern's Proposals and Consistency with Ratemaking Principles</u>

Q. Would the Company and its customers benefit from regulatory reform?

A. Yes. As explained below, consistent with universal ratemaking principles, the proposed alternative ratemaking treatment would provide important benefits to both customers and the Company.

Q. What are ratemaking principles?

A. In his seminal text <u>Principles of Public Utility Rates</u>, James C. Bonbright outlined the principles of a sound rate structure, as summarized in Figure 13 below:

Figure 13: Ratemaking Principles and Regulatory Objectives[36]

Ratemaking Principle	Regulatory Objectives
Economic Efficiency	▪ Rates are cost-based ▪ Rates encourage efficient consumption of resources ▪ Rates encourage prudent cost control
Equity	▪ Rates are non-discriminatory ▪ Fair allocation of costs and risks ▪ Avoidance of cross-subsidization
Revenue Adequacy and Stability	▪ Revenue sufficient to ensure financial integrity and encourage new investment ▪ Recovers prudent utility costs ▪ Profit stability
Bill Stability	▪ Rate Stability and continuity ▪ Avoidance of rate shock ▪ Affordability
Public Acceptance	▪ Simplicity & understandability ▪ Reliable service ▪ Moderate regulatory burden ▪ Promotion of social objectives

As discussed below, the Company's proposed mechanisms reflect these ratemaking principles that are intended to satisfy multiple, yet sometimes conflicting, objectives. For example, rates set through traditional regulation may be cost-based and encourage cost control; however, they

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[36] Sources: Adapted from James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, 2nd Edition, Public Utilities Reports (March, 1988); *Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives*, National Regulatory Research Institute (April 2014); *Alternative Electricity Ratemaking Mechanisms Adopted By Other States*, Christensen Associates prepared for Public Utility Commission of Texas (May 25, 2016); *Alternative Regulation for Emerging Utility Challenges: 2015 Update, Edison Electric Institute* (November 11, 2015).

may conflict with the objective of revenue sufficiency in an environment of increasing non-revenue producing capital investment and flat sales. Additionally, traditional regulation may conflict with the objectives of rate stability and avoidance of rate shock when large capital projects are included in rates at once.

Q. Turning now to the Company's proposed alternative ratemaking mechanisms, how do its proposals align with sound ratemaking principles?

A. First, the Company's Enhanced Wildfire Mitigation Plan Rider and Business Technology Mainteance Cost Escalation Rider propose to recover projected costs. The use of forward-looking cost estimates would more closely align the costs NorthWestern expects to incur with those recovered during the time rates are in effect, avoiding intergenerational subsidization. In other words, today's customers pay the cost of (and receive the benefits from) the proposed investments contemporaneously, as opposed to future customers paying for yesterday's costs for services and benefits they may not have received. Additionally, the Enhanced Wildfire Mitigation Plan Rider, Business Technology Mainteance Cost Escalation Rider, and Reliability Rider would enable the Company to proactively address safety and reliability concerns necessary to meet its obligation to provide safe and reliable service.

Second, the proposed Fixed Cost Recovery Mechanism ("FCRM") pilot design would encourage efficient consumption of resources by breaking the link between sales volume and revenues, removing the disincentive to promote conservation measures. It would promote equity by fairly enabling recovery of the Company's fixed costs, while mitigating cross-subsidization that may affect low-income and low-volume customers.

Lastly, the proposals would each enable revenue and bill stability, mitigating rate shock, improving rate stability, and support the Company's financial integrity all to customers' benefit.

Q. Will the Company's proposed mechanisms guarantee it will earn its authorized rate of return?

A. No. The proposals are intended to mitigate regulatory lag, however regulatory lag would not be eliminated. The Enhanced Wildfire Mitigation Plan Rider and Business Technology Mainteance Cost Escalation Rider proposals reflect small, incremental reforms that would more closely align the costs reflected in rates with those experienced in the period rates are in effect and improve the timeliness of cost recovery. Further, the proposed FCRM pilot only addresses the revenue component of the income statement, not operating expenses or rate base investment, and is designed to recover only the amount of revenue authorized by the Commission.

As explained earlier, under traditional regulation, utilities rely on incremental revenues beyond the rate year as a means of maintaining a reasonable rate of return on investment in between rate reviews. Those additional funds historically have financed necessary capital investment and helped offset inflationary pressures. When the costs of providing utility service escalates faster than sales (and therefore revenue), the utility's rate of return will likely erode in the long run. Decoupling mechanisms therefore may stabilize a utility's revenues and improve its financial integrity, enabling the utility to provide safe and reliable service to customers. Decoupling does not, however, guarantee a base level of earnings or rate of return, nor does it create windfall profits for the utility.

Q. How do customers benefit from the proposed alternative ratemaking mechanisms?

A. As discussed throughout my testimony, the proposed mechanisms support the Company's financial integrity to the benefit of customers. A financially-healthy utility has a greater capability to invest in its system and provide safe and reliable service. Further, as Ms. Lail explains, a utility's credit rating depends largely on its financial integrity; a higher credit rating results in lower capital costs for customers. Lastly, a financially-healthy utility can better withstand unexpected adverse business, economic, and market conditions.

Q. Why should the Commission approve the Company's proposed alternative ratemaking mechanisms?

A. The proposed mechanisms alleviate (but do not necessarily eliminate) the challenge of regulatory lag, eroding revenues, and increasing costs, while providing benefits to customers. Without timely cost recovery, certain of these critical expenditures might be deferred or reduced. Moreover, certain of the investments proposed for recovery are non-revenue producing. In particular, the investments proposed in the Company's Enhanced Wildfire Mitigation Plan Rider and Business Technology Mainteance Cost Escalation Rider do not generate incremental revenues to offset the expenditures being made. For these reasons, the Commission should approve the Company's proposed alternative ratemaking mechanisms.

VI. Conclusions and Recommendation

Q. What are your conclusions regarding the Company's proposed alternative rate mechanisms?

A. NorthWestern's proposals arise from circumstances that have affected many utilities around the country. The challenging combination of declining use per customer and increasing non-revenue producing investment required to maintain service quality and reliability has resulted in an environment that is increasingly difficult under traditional regulation to maintain a healthy financial profile that benefits both customers and the Company. In my opinion, the Company's proposals reflect small, reasonable changes that are consistent with sound ratemaking principles and are similar to mechanisms approved in other jurisdictions. Additionally, they would mitigate (but not necessarily eliminate) earnings attrition and improve the Company's opportunity to earn a fair return. Therefore, I recommend the Commission approve the Company's proposed mechanisms.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

VERIFICATION

This Pre-filed Direct Testimony of Jennifer E. Nelson is true and accurate to the best of my knowledge, information, and belief.

/s/ Jennifer E. Nelson
Jennifer E. Nelson