414 Nicollet Mall
Minneapolis, Minnesota 55401

December 21, 2017

—VIA ELECTRONIC FILING—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

RE: COMMENTS
PERFORMANCE METRICS AND INCENTIVES
DOCKET NO. E002/CI-17-0401

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the attached Comments in response to the Minnesota Public Utilities Commission's Notice of Comment Period dated September 22, 2017.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies of the summary on the parties on the attached service lists.

If you have any questions regarding this filing please contact Pamela Gibbs at (612) 330-2889 or pamela.k.gibbs@xcelenergy.com or me at (612) 215-4663 or aakash.chandarana@xcelenergy.com.

Sincerely,

/s/

AAKASH H. CHANDARANA
REGIONAL VICE-PRESIDENT RATES &
REGULATORY AFFAIRS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE COMMISSION INVESTIGATION TO IDENTIFY AND DEVELOP PERFORMANCE METRICS AND POTENTIALLY, INCENTIVES FOR XCEL ENERGY'S ELECTRIC UTILITY OPERATIONS

DOCKET NO. E002/CI-17-401

COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission these Comments in response to the Commission's September 22, 2017 Notice of Comment Period in the above noted docket. We are the first and only Minnesota utility operating under a multiyear rate plan (MYRP) enabled by Minn. Stat. § 216B.16, subd. 19, which provides in part for the Commission to require a utility to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies. The Notice seeks an understanding of how performance metrics and standards, and potentially incentives, could further align our focus with the public interest.

To that end, the first phase of the Commission's inquiry and this set of comments focuses on stakeholder input about key goals for the electric sector; how performance against those goals is currently measured; which metrics or information should be used to determine whether the utility is meeting those key goals; and, what utility or independent information would aid in establishing achievable potential for performance against those key goals. The second phase will focus on how the performance measurements and standards developed in the first phase may be used or applied by the commission, including possible standards or performance targets – and the potential for using financial incentives to drive our performance.

We believe the Commission's inquiry started in the right place: identifying the key goals of utility regulation. We further believe that the Commission, in its Notice, identified the key objectives of utility regulation: ensuring reasonable and affordable rates, reliable service, customer service and satisfaction, and environmental performance. It is no surprise that the Commission's goals align closely with Minnesota state energy policy and the interests of our customers, who have frequently and clearly articulated their desire for clean, affordable and reliable energy service. We share these goals, and we believe our track record demonstrates that we are an engaged and willing partner.

For instance, our record on environmental performance is exemplary. We are on track to have a generating fleet that is 63 percent carbon-free by 2030 – and with the right policy framework, we may be able to further transition our fleet to achieve even greater levels of carbon reductions. In 2017, and for more than a decade, we have been named the number one wind provider in the United States by the American Wind Energy Association. Additionally, we have announced the only 80 percent Production Tax Credit (PTC) project in the country to-date – and we are on pace to become the first company in the nation to have more than 10,000 MWs of wind.

We have a similarly strong record on reliability, ranking in the first or second quartile nationally in terms of System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) – and have received national recognition for our storm response efforts. Also, significantly, we are achieving these outcomes with total residential customer bills that are 27 percent below the national average and 14 percent lower than the Minnesota utility average. In fact, our Minnesota residential customers have actually experienced a two percent *decrease* in their total bill since 2013. Additionally, our recent efforts in the wind and biomass space will deliver over $2.2 billion in savings to our customers.

Additionally, our customers have saved over 3,038 MW in electric energy, thereby avoiding the construction of approximately 12 power plants. We have the most registered demand response capability (nameplate) of all Midcontinent Independent System Operator (MISO) investor owned utilities by a significant margin – and are on pace to significantly increase those resources by 2023.[1] We are finding new and better ways to communicate with our customers, including redesigning our website to be customer-centric, developing a state-of-the-art Storm Center and outage notification system, and rolling out a mobile application.

These achievements are an indication that our current regulatory model – while not

[1] Brattle analysis of FERC, *2012 Assessment of Demand Response and Advanced Metering*, and EIA 861 load data. Based on capability of dispatchable DR (830 MW), so excludes impacts from static TOU rates. Capability calculated as current portfolio divided by 2016 peak load.

perfect – is sound. Key regulatory outcomes are being achieved – and then some. It is with that context that we embark on an evaluation of Performance Based Ratemaking (PBR) tools. Minnesota is well-positioned in that we are operating from a positon of strength and stability. Moreover, in Minnesota, alternative regulatory tools including PBR are not novel. We already utilize PBR tools including multi-year rate plans, cost trackers and riders, performance metrics and performance-based incentive and penalty structures.

Stated differently, Minnesota regulation is not in need of an overhaul. Rather, we believe this analysis of the role of PBRs should be focused away from core regulatory objectives – which are being achieved – and toward identifying more targeted opportunities. For instance:

- Can we find ways to shave our system peak?
- Can we shift load to times when energy is more abundant (lower cost) on the system?
- How can we measure the levels of distributed energy resources (DER) that are coming onto the system?
- How do we encourage continuous improvement with respect to our interconnection process?
- How can we bring our expertise on reducing carbon emissions to other industries to further state policy goals?

We recognize that there are opportunities for the Company to improve performance in new and different ways, and we are open to that. That said, we will advocate for a principled approach grounded in cautious and thoughtful deliberation in order to preserve the great outcomes that we are collectively delivering. To that end, it will be important for the Commission to adhere to key design principles recognized among PBR experts as foundational to effective performance regulation. These principles are universally recognized and include:

- Tying any objectives to policy goals;
- Ensuring objectives are clearly defined, can be quantified using reasonably available data, are sufficiently objective and free from external influences;
- Excluding the effects of factors outside a utility's control; and
- Easily verified.

To aid in this effort, we have enlisted the help of Dr. Mark N. Lowry. With more than 30 years as an industry economist internationally recognized for his work in the fields of PBR and utility performance measurement, Dr. Lowry can help us understand the relative sophistication of our current regulatory paradigm and where there are opportunities to stretch and grow—without adversely impacting the central objectives of safe, affordable, reliable and environmentally responsible service. We asked Dr. Lowry to provide his report in a question and answer format for purposes of clarity and ease of understanding. Dr. Lowry's report is provided as Attachment A to these Comments.

The remainder of our Comments are organized as follows:

- Section I outlines the policy basis of the key goals of electric utility regulation in Minnesota.
- Section II discusses our customers' priorities and expectations.
- Section III addresses how core regulatory objectives are currently being achieved.
- Section IV outlines how we are evolving the grid and meeting changing customer expectations.
- Section V discusses key PBR design principles and potential opportunities to expand performance metrics and/or incentives.

I. KEY GOALS OF UTILITY REGULATION

Federal and state policies and requirements – and customers – determine the key goals of utility regulation. We believe the regulatory construct and the attributes of our service that customers value are aligned around reasonable and affordable rates, reliable service, customer service and satisfaction, and environmental performance.

On a federal level, we are subject to Federal Energy Regulatory Commission (FERC) authority, which oversees transmission, and bulk, non-retail energy sales and markets, scrutinizes the reliability of the transmission system through mandatory reliability standards, monitors and investigates energy markets, administers accounting and financial reporting regulations, and regulated entity conduct – and enforces its requirements through civil penalties and other means.

The principal source of state policy with respect to energy, utilities, and the environment are Minnesota statutes. Indeed, in the Legislative Findings section of Minn. Stat. Chapter 216B, the legislature provided a topline summary of state policy with respect to utility regulation:

> *It is hereby declared to be in the public interest that public utilities be regulated as hereinafter provided in order to provide the retail customers of natural gas and electric service in this state with adequate and reliable services at reasonable rates, consistent with the financial and economic requirements of public utilities and their need to construct facilities to provide such services or to*

> *otherwise obtain energy supplies, to avoid unnecessary duplication of facilities which increase the cost of service to the consumer and to minimize disputes between public utilities which may result in inconvenience or diminish efficiency in service to the consumers.*[2]

Likewise as to environmental policy, the Legislature provides an overarching "Declaration of State Environmental Policy" in Minn. Stat. § 116D.02:

> *The legislature, recognizing the profound impact of human activity on the interrelations of all components of the natural environment, particularly the profound influences of population growth, high density urbanization, industrial expansion, resources exploitation, and new and expanding technological advances and recognizing further the critical importance of restoring and maintaining environmental quality to the overall welfare and development of human beings, declares that it is the continuing policy of the state government, in cooperation with federal and local governments, and other concerned public and private organizations, to use all practicable means and measures, including financial and technical assistance, in a manner calculated to foster and promote the general welfare, to create and maintain conditions under which human beings and nature can exist in productive harmony, and fulfill the social, economic, and other requirements of present and future generations of the state's people.*

Finally, the legislature broadly addressed energy planning in Minn. Stat. § 216C.05 finding and declaring:

> *…the state has a vital interest in providing for: increased efficiency in energy consumption, the development and use of renewable energy resources wherever possible, and the creation of an effective energy forecasting, planning, and education program…The legislature intends to monitor, through energy policy planning and implementation, the transition from historic growth in energy demand to a period when demand for traditional fuels becomes stable and the supply of renewable energy resources is readily available and adequately utilized….That for economic growth, environmental improvement, and protection of citizens, it is in the public interest to encourage those energy programs that will provide an optimum combination of energy resources, including energy savings.*
>
> *Subd. 2.* **Energy Policy goals.** *It is the energy policy of the state of Minnesota that:*
> *(1) annual energy savings equal to at least 1.5 percent of annual retail energy sales of electricity and natural gas be achieved through cost-effective energy efficiency;*
> *(2) the per capita use of fossil fuel as an energy input be reduced by 15 percent by the year 2015, through increased reliance on energy efficiency and renewable energy alternatives;*
> *(3) 25 percent of the total energy used in the state be derived from renewable energy resources by the year 2025; and*
> *(4) retail electricity rates for each customer class be at least five percent below the national average.*[3]

[2] Minn. Stat. § 216B.01
[3] Subd. 2(4) was added in the 2017 legislative session.

Aside from these general statements, Minnesota statutes also articulate a number of more specific policies related to affordability, reliability, energy efficiency, environmental performance, and other issues – and provide non-traditional regulatory mechanisms to further state policy objectives or to address emergent business conditions – all of which should be taken into consideration in this docket. We briefly discuss each category in turn below.

A. Reasonable and Affordable Rates

With respect to affordability, the legislature has delegated to the Commission the responsibility to ensure that all rates charged to customers are "just, reasonable, equitable, and consistent in application."[4] Beyond that, there are a number of statutes that encourage and/or mandate certain actions to maintain affordable electricity rates. These include requirements that provide for certain low-income affordability programs,[5] protections for medically-necessary equipment,[6] and protections for customers during extreme heat conditions or when cold weather rules are in effect.[7]

Traditionally, utility rates are set based on the utility's cost of service, and are subject to periodic review in general rate cases. Rate cases include allocating costs to various classes of customers, establishing the utility rate of return, and may include proposals to change customer rate designs or other changes to the way utilities recover the cost of providing utility service. All costs and rates are scrtunized, and are subject to prudence review and disallowance. General rate cases are complex and labor intensive for utilities, regulators, and other stakeholders that choose to participate.

Recently, the legislature passed a MYRP statute.[8] As discussed in Dr. Lowry's testimony, MYRPs are alternative rate tools that qualify as PBR because they encourage cost containment during the course of the plan, which in turn controls customer rates. By reducing rate case frequency, MYRPs also reduce regulatory burden. Other alternative rate tools in the Minnesota regulatory construct include rate riders, which provide utilities a path to timely cost recovery of actual costs for specific functions. These include fuel costs, and extraordinary expenditures for significant infrastructure investments that further state policy objectives. Rate riders use cost trackers that are subject to a focused review of proposed investments and forecasted and actual expenditures – and may contain other cost containment features, such as cost caps, which is the case with our Transmission Cost Recovery (TCR) rider, or

4 Minn. Stat. § 216B.01, 03.
5 Minn. Stat. § 216B.16, subds. 14-15.
6 Minn. Stat. § 216B.098, subd. 5.
7 Minn. Stat. § 216B.096.
8 Minn. Stat. § 216B.16, subd. 19 (2011, and modified in 2015).

incentives, which was the case with our Metro Emissions Reduction Project (MERP).

In addition to being subject to need assessments, the Commission may require competitive bidding processes for identified resource acquisition needs, as provided in Minn. Stat. § 216B.2422, subd. 5 – or impose other cost containment strategies and requirements. For example, we participated in the bidding process for wind resources from our 2016-2030 IRP in Docket No. E002/M-16-777. The Commission approved selection of our fixed-price portfolio of 1,150 MW of Company-owned wind, out of a total of 1,550 MW selected from the bid process.[9] In that case, our proposed projects competed on equal footing with other bidders and were selected.

Finally, the legislature has also recently passed amendments to Minn. Stat. § 216B.2424, which permit the amendment or early termination of Biomass Power Purchase Agreements (PPA), or the purchase and closure of biomass facilities, if those actions will result in customer savings. We have taken advantage of these legislative changes and filed several biomass-related petitions with the Commission. In total, we have estimated that these proposals would result in customer savings in excess of $430 million.

B. Reliable Service

In terms of electric service, both state and federal requirements come into play. Minnesota statutes require that electric service be "safe, adequate, efficient, reasonable, and reliable" – and subject public utilities to the Commission's authority regarding many aspects of that service, including technical standards on service quality, testing, and equipment performance.[10] FERC prescribes the reliability standards for the transmission system, which are implemented by the North American Reliability Corporation (NERC) and MISO. NERC enforces its reliability standards through audits and penalty assessments. MISO prescribes resource adequacy requirements and facilitates regional transmission planning and other activities that ensure utilities – and the regional grid – have is sufficiently robust to serve present and future regional electricity needs.

The legislature has also given the Commission authority to order public utilities to make adequate infrastructure investments and undertake sufficient preventative maintenance in order to provide reliable service.[11] The Commission evaluates

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[9] *See* ORDER APPROVING PETITION, GRANTING VARIANCE, AND REQUIRING COMPLIANCE FILING (September 1, 2017)
[10] Minn. Stat. § 216B.01, 04, 09.
[11] Minn. Stat. § 216B.79.

transmission and resource adequacy through utility IRPs,[12] certificates of need (CN),[13] and biennial transmission reports from Minnesota Transmission Owners. IRPs plan for the capacity, energy, and emissions requirements of the electric system, resulting in a common vision of the future – and a plan that ensures sufficient resources to meet customer needs. CNs assess the need for large energy facilities, and among other things, the relationship of the proposed facilities to overall state energy needs.

The biennial transmission reports required under § 216B.2425 include identifying possible solutions to anticipated "inadequacies" in the transmission system, which is defined as a situation where the present transmission infrastructure is unable or likely to be unable in the foreseeable future to perform in a consistently reliable fashion and in compliance with regulatory standards. The Commissioner of Commerce must report annually to the legislature regarding transmission adequacy in the state and what progress is being made to meet transmission infrastructure needs.[14]

With respect to the distribution system, the Commission's Rules prescribe requirements and measures that apply to all utilities in the areas of reliability, safety, customer billing, utility responsiveness, equipment testing and performance, and various customer protections. The Commission evaluates utility reliability performance, and distribution system actions to maintain its system as part of an annual Service Quality reporting process under Minn. R. 7826 (which also includes other aspects of utility performance).

We additionally are the only utility in Minnesota subject to specific reliability and other performance standards that include a financial penalty for failure to meet the associated performance threshold in any year.[15] The underperformance penalty is $1 million for each of the seven measures – two of which are reliability-based: System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI); the Quality of Service Plan (QSP) also provides for underperformance payments to customers experiencing certain multiple or lengthy outages ranging from $50 to $200.[16]

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[12] Minn. Stat. § 216B.2422 and others as detailed in Appendix A to the Xcel Energy Upper Midwest Resource Plan 2016-2030, Docket No. E002/RP-15-21 (January 2, 2015).
[13] Minn. Stat. § 216B.243
[14] Minn. Stat. § 216C.054.
[15] Minnesota Electric Rate Book – MPUC No. 2, Section 6 General Rules and Regulations, Section 1.9, Service Quality, Sheet Nos. 7.1 – 7.11. Minnesota Gas Rate Book – MPUC No. 2, Section 6 General Rules and Regulations, Section 1.9, Service Quality, Sheet Nos. 7.1 – 7.11.
[16] All underperformance payments are borne by our shareholders and are not recoverable in future rate proceedings.

C. Customer Service and Satisfaction

The Commission's current requirements for utility electric service quality are based in Minnesota Rules. Service quality reporting requirements are contained in Minn. R. 7826, and cover a broad range of utility service including safety, reliability, billing accuracy, responsiveness, and customer protection.[17] We outline our present reporting requirements in Attachment B. Additionally, while there are no associated reporting requirements, Minn. R. 7820 specifies other utility service responsibilities, requirements and operating parameters in the areas of customer information and complaints, temporary and extended service, disconnection of service, adjustment of gas and electric bills, deposit and guarantee requirements, public access to information, and delinquency charges.

Our electric and natural gas tariffs also contain service provisions similar to those prescribed in Minnesota statutes and Rules, with a notable difference in the requirements for malfunctioning meters (Minn. R. 7826.1000). The Rule prescribes a ten-day timeframe to replace a malfunctioning meter. Our tariff contains a similar general timeframe to remedy the malfunctioning equipment, but adds a penalty for failing to act in the specified timeframes – prohibiting us from billing customers for any under-billing amounts resulting from the malfunctioning meter equipment. The tariff also requires annual reporting of our investigatory and remedial action performance in accordance with prescribed timeframes.

In addition to reliability measures, the QSP in our electric and natural gas tariffs prescribes performance thresholds – and underperformance payments for failure to meet those thresholds (with no upside incentives) –in terms of our: Telephone Response Time; Natural Gas Emergency Response; Customer Complaints; Accurate Invoices; and Invoice Adjustment Timeliness.

D. Environmental Performance

In terms of the environment, Minnesota has long been a leader and has prescribed policies that advance utility environmental consciousness and performance. Utility environmental performance is monitored and evaluated at the federal and state levels by the Federal Environmental Protection Agency (EPA), the Minnesota Pollution

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[17] The Commission's requirements for utility annual electric service quality reporting currently fall under Minn. R. 7826.0400, 7826.0500, and 7826.1300. Utilities are additionally required to propose reliability standards for the following year under Minn. R. 7826.0600, and comply with various reporting requirements as specified in Commission Orders approving these reports. As a rate-regulated natural gas utility, we also report on various aspects of our natural gas service quality, which were established via a Commission Order in an investigatory docket. *See* ORDER SETTING REPORTING REQUIREMENTS, *In the Matter of a Commission Investigation Into Gas Utility Service Quality Standards*, Docket No. G999/CI-09-409 (August 26, 2010).

Control Agency (MPCA), and the Commission.

Minnesota statutes comprehensively guide utilities' environmental performance. Most notably, the Next Generation Energy Act of 2007 (NGEA) increased energy efficiency goals, established statewide goals to reduce greenhouse gas emissions, supplemented the already existing Renewable Energy Standard (RES).[18] The NGEA established a statewide goal to reduce greenhouse gas emissions across all sectors to a level of at least 15 percent below 2005 levels by 2015, 30 percent below 2005 levels by 2025, and to at least 80 percent below 2005 levels by 2050.[19] The RES requires utilities to generate at least 25 percent of their total retail electric sales by eligible technologies by 2025.[20] However, the standards hold Xcel Energy to an even higher bar, requiring that it generate at least 30 percent of its total electric retail sales by eligible technologies.

In conjunction with establishing these standards, the legislature also passed statutory changes to facilitate investment in infrastructure improvements that enhance environmental performance, and to encourage the acquisition of renewable projects and the cost recovery of those projects.[21] In recent years, the energy policy landscape has continued to evolve. For example, to encourage solar energy development through a Solar Energy Standard (SES), which encourages adoption of solar energy resources and the development of distributed generation, including in the form of community solar gardens – and policies that favor electric vehicles (EV).[22]

Utility environmental performance and alignment with state policy objectives are assessed by the Commission in IRP proceedings, CNs for energy infrastructure, and resource procurement proceedings. For example, these proceedings evaluate utilities' progress toward state greenhouse gas emissions reduction targets, and utilities' consideration of renewable resources prior to the addition of large, non-renewable generating resources.[23]

The state has further demonstrated its commitment to the environment through the passage of specific legislation such as MERP, which encouraged the Company to go beyond compliance with respect to certain existing electric power plants.[24] Under MERP, we converted two metro area coal generating facilities to natural gas, and

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[18] 2007 Minnesota Session Laws, Chapter 136 – S.F.No. 145.
[19] Minn. Stat. § 216H.02.
[20] Minn. Stat. § 216B.1691.
[21] Minn. Stat. §§ 216B.1645, subd. 2a. (cost recovery for renewable projects); 216B.243, subd. 9 (resource acquisition of renewable facilities).
[22] Minn. Stat. § 216B.1614.
[23] Minn. Stat. § 216B.243, subd. 3a.
[24] Minn. Stat. § 216B.1692

installed significant state of the art pollution control technology on a third. The plan achieved significant environmental benefits that were not otherwise required by law. We recovered our costs through a Rate Rider, which included a sliding scale rate of return that incented the Company to contain costs and implement the plan as efficiently and effectively as possible.[25] Other legislative amendments have enabled utility cost recovery for actions that reduce greenhouse gases through replacement of certain infrastructure. For example, amendments to Minn. Stat. § 261B.1637 facilitated replacement of our remaining cast iron natural gas pipe through our State Energy Policy (SEP) rider – and, replacement of sulfur hexafluoride circuit breakers on our transmission system through our TCR.

With respect to energy efficiency, there are several specific statutory measures that govern utility performance and regulation. Minnesota's Conservation Improvement Program (CIP) – enabled by Minn. Stat. § 216B.16, subd. 6(c) – benefits not only customers who invest in energy-efficient measures, but also other customers and members of society. Energy efficiency reductions allow utilities to avoid the cost of constructing new power plants, transmission lines, natural gas pipelines, and distribution systems. The state goal is to achieve at least 1.5 percent savings in annual retail energy sales through conservation improvement programs, energy codes, appliance standards, and other energy efficiency efforts by consumers and utilities.[26] In fact, as part of the State's commitment to investing in conservation, Xcel Energy is required to spend two percent of its gross Minnesota revenues on conservation improvements.[27] Minnesota has also demonstrated its commitment to energy efficiency through its support of decoupling, the express purpose of which is "to reduce a utility's disincentive to promote energy efficiency."[28]

In all of these ways, we believe the policy goals for utility regulation in Minnesota as outlined by the legislature are aligned with those identified by the Commission. We further believe that our actions and performance as measured against these policies and goals demonstrates that we are strongly aligned with the Commission – and that we routinely outperform, relative to other utilities in Minnesota and nationally. We address our record in greater detail in the next section along with outlining some of the ways our performance is currently measured.

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[25] *See* ORDER APPROVING XCEL'S PROPOSED PLAN, SUBJECT TO THE TERMS OF A SETTLEMENT AGREEMENT AND ADDITIONAL CONDITIONS AND CLARIFICATIONS at page 17, Docket No. E002/M-02-633, (March 8, 2004).
[26] Minn. Stat. § 216B.2401
[27] Minn. Stat. § 216B.241, subd. 1a.
[28] Minn. Stat. § 216B.2412, subd. 1.

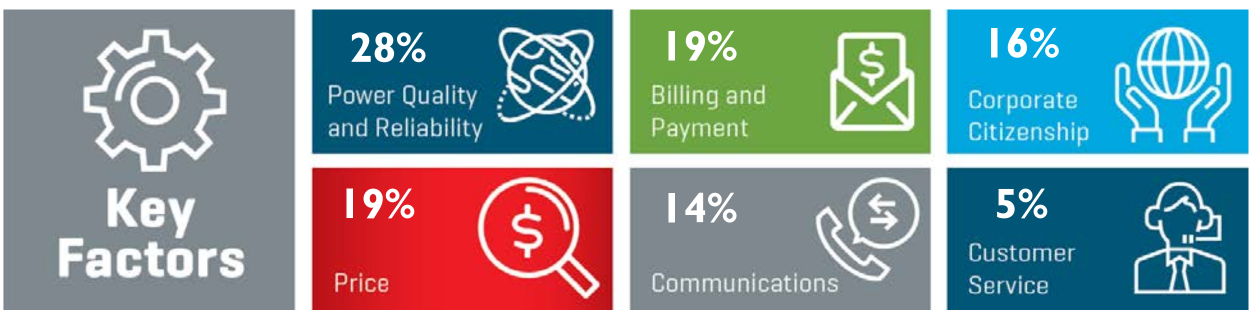
II. CUSTOMER EXPECTATIONS FOR UTILITY SERVICE

We firmly believe that our customers' voices and priorities should inform any discussion regarding the goals that should be pursued when regulating utilities in Minnesota. We regularly survey our customers to learn about what they value with regard to our products, services, and performance. We use these learnings to make decisions about our own business, and believe the Commission and our stakeholders should likewise take them into account when making decisions in this docket.

In this section, we discuss the utility service attributes that are important to customers, which largely align with the key objectives of utility regulation the Commission identified in this proceeding. We also discuss how we believe our customers' expectations should shape the discussion in this proceeding.

Residential utility customer satisfaction continues to be driven by the following six elements:

Figure 1: JD Power Residential Customer Satisfaction Driver Weighting



Source: J.D. Power 2017 Electric Utility Residential Customer Satisfaction Study

Drivers of satisfaction among business customers are similar – placing the greatest emphasis on Power Quality and Reliability (at 22 percent) and Customer Service (at 12 percent).

Breaking down these results, in terms of satisfaction with power quality and reliability, our customers expect reliable, quality electric service, prompt restoration when there is an outage, avoidance of brief interruptions and lengthy outages, and good communication about outages when they occur.

When it comes to price, customers consider the total monthly cost of their electric service in determining their level of satisfaction. Other key considerations include the clarity of the bill, the efforts of the utility to help manage monthly usage, perceived fairness of the pricing, and availability of pricing options. Notably, customer research demonstrates the importance of maintaining a balance between cost and service. For example, customers tell us that price is important to them, but not at the expense of reliability.

Our customers also expect accurate, timely bills that contain useful information. They want flexible and convenient billing and payment options – and a variety of methods to pay their bills. Also, our customers increasingly expect the Company to be a good and active corporate citizen, to offer a variety of energy efficiency programs, to take action to care for the environment, and to develop energy supply plans for the future.

Finally, our customers expect that we provide them timely information about our service, how to be safe around electricity, how to manage their costs, and how to reduce energy use. In terms of customer service, our customers expect our employees to be knowledgeable, empathetic, clear, and courteous – and they expect a prompt response when they want to speak to a representative. They expect the digital customer service tools that we offer to be easy to navigate and understand, and they expect timely resolution of their issues and questions.

Within these categories, customers' expectations are increasingly focused on the provision of timely and personalized information; a more seamless and simple customer experience; and lifestyle products and services. For example, we know that:

- Energy efficiency awareness lifts price satisfaction,
- Price satisfaction increases when customers perceive improved reliability, infrastructure investment, or improved power supply,
- Value-added billing features increase satisfaction,
- Reliability satisfaction is higher if power is restored within 20 minutes of the estimated restoration time – and is significantly higher if the utility uses proactive communication to provide information about an outage using email or text messages, and the utility's social media site. It also increases with the number of touchpoints a utility has with a customer during an outage, and
- Nearly all customers believe it is important to have a seamless customer experience with their energy provider across all digital and non-digital channels – and would be more satisfied if their energy provider could personalize their overall customer experience.

Strong communication and convenient, simple communication tools are central to customer satisfaction. As noted previously, we have taken the initiative to find new and better ways to communicate with our customers, including a state-of-the-art Storm Center and outage notification system – and a mobile application. We have worked hard to deliver on our customers' expectations and we remain focused on continuing to provide our customers with high quality service.

III. CORE REGULATORY OBJECTIVES ARE BEING ACHIEVED

In this section, we discuss our performance in the context of the key goals of utility regulation as discussed in the prior sections of our comments.

A. The Multi-Year Rate Plan Aligns with the Goal of Affordability

We first utilized Minnesota's MYRP ratemaking tool in its general rate case in Docket No. E002/GR-13-868, which ultimately resulted in a two-year rate plan. The statutory amendments in 2015 allowed for up to a five-year MYRP, which we utilized in our most recent rate case in Docket No. E002/GR-15-826.[29] We are currently operating under the first four-year MYRP in Minnesota.

As Dr. Lowry discusses, MYRPs are an effective form of PBR. They increase the incentive for utilities to operate efficiently by loosening the link between a utility's costs and its revenues – strengthening the incentive for utilities to contain costs. Customers realize these efficiencies through rates that are locked-in for the period. As such, our MYRP is the foundational PBR. We acknowledge that for MYRPs to be fully-effective, they should be paired with reasonable regulatory oversight to ensure the utility's efficiencies do not compromise the level of service they provide to their customers.

Our present MYRP expressly recognizes the Commission's continuing oversight pursuant to Minn. Stat. § 216B.16, subd. 19(e), provides for several measures that are intended to ensure our investments during the term are aligned with state and customer priorities—additionally, it did not disturb the Company's existing QSP Tariff. Specifically, there is an annual capital true-up to ensure we continue to invest in our system at approved levels; we are limited to utilizing only existing rate Riders, which helps to control customer costs while ensuring we can continue to invest in our infrastructure consistent with state policy objectives, subject to regulatory review of the proposed expenditures. Finally, the Commission-approved decoupling mechanism from our previous rate case was extended for the term of the MYRP, which continues to remove any disincentive from encouraging conservation and distributed generation with our customers.

Our present MYRP strikes a reasonable and intentional balance between the incentives for efficient operation, continued delivery of high quality service, and regulatory oversight. We discuss each of these measures below.

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[29] Minn. Stat. § 216B.16, subd. 19 (2015).

B. Service Quality is Regularly and Thoroughly Measured

As we have noted, in addition to the service quality requirements contained in the Commission's Rules, we are subject to a tariff-based QSP tariff, where failure to meet an annual performance threshold results in a per-metric underperformance penalty of $1 million. We have not incurred a Company underperformance payment for missing a performance threshold under the present QSP. However, we have paid an average of approximately $520,000 in outage credits per year to customers. We discuss our QSP in more detail below.

1. QSP Background

Our present QSP tariff has been evolving since the late 1990s, as business conditions have changed. It started with meter reading and billing performance goals and included penalties for unread meters, inaccurate estimated bills, inaccurate average-monthly bill amounts, over-reliance on estimated bills, and untimely bills.[30] The plan's first evolution was in conjunction with the Northern States Power Company merger with New Century Energies, Inc. to become Xcel Energy in 2000, where more robust service quality metrics became a condition of the merger.

The next generation of service quality required quarterly reports on meter reading performance, outage performance, and customer complaints, and had an annual $100,000 per-metric penalty in the event we did not meet threshold performance levels for telephone response time, customer complaints to the Commission, natural gas line mislocates, SAIDI, and SAIFI. The plan also included $30 outage credits to customers experiencing six or more sustained electric service interruptions per year.[31]

In early 2004, the Commission approved a QSP tariff largely aligned with the present day tariff provisions.[32] There were some changes in the ensuing years, and a full review and renegotiation of the QSP's terms in the 2012-2013 timeframe. The present QSP tariff reflects those efforts and:

- Provides assurance that we will continue to provide our customers safe, adequate, efficient and reasonable service,
- Focuses the plan on key attributes of our service that matter most to our customers – removing those that were no longer relevant and adding new metrics where appropriate,

[30] *See* ORDER ACCEPTING STIPULATION AND SETTLEMENT, Docket No. E,G002/CI-97-863 (March 3, 1998).
[31] *See* ORDER APPROVING MERGER, AS CONDITIONED, Docket No. E,G002/PA-99-1031 (June 12, 2000).
[32] *See* ORDER ACCEPTING SETTLEMENT AGREEMENT, AS MODIFIED, Docket No. E,G999/CI-02-2034 (March 10, 2004).

- Established a relevant basis and calculation methodology for each performance threshold,
- Retained significant penalties for underperformance while simplifying the payment structure, and
- Expanded customer outage credits to address customers' experience over consecutive years.

The Commission approved the present QSP tariff in its August 12, 2013 Order in Docket Nos. E,G002/CI-02-2034 and E,G002/M-12-383.

2. QSP Tariff Metrics

The present QSP tariff prescribes performance thresholds for the following attributes of our service to customers:

- *Customer Complaints*. Measures the number of customer complaints submitted by the Commission's Consumer Affairs Office. An underperformance payment is assessed in any year in which the number of complaints exceeds 0.2059 complaints per 1,000 customers.
- *Reliability – SAIDI*. Measures our System Average Interruption Duration Index, or SAIDI, which is an industry standard reliability measure of the annual average outage duration on our distribution system. An underperformance payment is assessed in any year in which our statewide SAIDI exceeds 133.23 minutes.
- *Reliability – SAIFI*. Measures our System Average Interruption Frequency Index, or SAIFI, which is an industry standard reliability measure of the annual average outage frequency on our distribution system. An underperformance payment is assessed in any year in which our statewide SAIFI exceeds 1.21 outage events.
- *Reliability – Customer Outage Refunds*. Intended to compensate individual customers whose homes or businesses incur outages unrelated to storms or other major events that exceed specific performance year standards. All customers are eligible for single-year outage credits, with different credit amounts for municipal pumping customers as compared to all other customers. All non-municipal pumping customers are also eligible for consecutive year outage credits that range from $75 for a customer after the second consecutive year the customer experiences five or more interruptions, to $125 for a customer if the customer experiences four or more interruptions in four consecutive years.
- *Billing Accuracy – Accurate Invoices*. Measures the overall accuracy of our customer

billing. An underperformance payment is assessed in any year in which our annual accuracy rate is less than 99.3 percent, as determined by the number of invoices cancelled for controllable reasons.

- *Billing Accuracy – Invoice Adjustment Timeliness*. Measures the timeliness of any necessary customer billing adjustments – or the "duration" of billing errors. An underperformance payment is assessed in any year in which the average annual number of cancelled billing periods exceeds 2.35.
- *Responsiveness – Telephone Response Time*. Measures our time to answer customer calls directed to our call center or to our business office. An underperformance payment is assessed in any year in which less than 80 percent of calls are answered within 20 seconds. This performance threshold is consistent with the 80/20 requirement under Minn. R. 7826.1200.
- *Responsiveness – Natural Gas Emergency Response*. Measures our average annual response time to natural gas emergency calls. An underperformance payment is assessed in any year in which our response time exceeds 60 minutes. The basis for this metric is Minnesota Office of Pipeline Safety industry guidance for the highest priority gas emergency response categories.

The metrics represent the areas the Commission and stakeholders agreed are key aspects of our service to customers. The metrics, calculation methodologies, and thresholds are rooted in our historic actual performance and based on relevant industry, Commission, and/or external benchmarks. Each metric has a defined calculation methodology and criteria that allows for exclusion of certain events from the calculations that is designed to isolate and measure the controllable aspects of our performance.

C. Environmental Objectives Are Being Accomplished

We briefly touched on our environmental performance record. In this section, we discuss our performance in the context of Minnesota's conservation objectives and renewable energy standards.

1. Conservation Improvement Program

Since the early 1990s, we have demonstrated a commitment to energy conservation. Between 1992 and 2016, we invested over $1.5 billion in our programs, which has resulted in approximately 8,300 GWh in electric energy savings, 3,038 MW of electric demand savings, and 14.9 million Dth of natural gas savings. From the capacity savings alone, we have avoided the construction of approximately 12 power plants.[33]

As it related to conservation, the NGEA encouraged utilities to aggressively pursue cost-effective energy conservation and reach new energy savings targets. Two statutes set energy savings targets and a mechanism for meeting those targets cost-effectively: (1) Minn. Stat. § 216B.241 subd. 1c established a statewide savings target of 1.5 percent, and a requirement for CIP plans to include savings goals of at least 1.0 percent savings in annual retail energy sales, and (2) Minn. Stat. § 216B.16, subd. 6c (c) (3) established the Commission's authority to approve a financial incentive mechanism, as follows:

> *The Commission may…adopt any mechanism that satisfies the criteria of this subdivision, such that implementation of cost-effective conservation is a preferred resource choice for the public utility considering the impact of conservation on earnings of the public utility.*

In January 2010, the Commission issued an Order creating the Shared Savings Financial Incentive Mechanism (Incentive Mechanism). The structure of the Incentive Mechanism positively correlates financial incentives with the amount of net benefits generated from its energy conservation programs. If a utility's conservation programs are not cost-effective, they generate no net benefits. Therefore, as cost-effectiveness increases, so do net benefits and financial incentives. The Incentive Mechanism is referred to as a "shared savings" mechanism because the utility shares a majority of the net benefits generated from conservation programs with its customers.

The Commission has revisited the Incentive Mechanism every few years to evaluate whether modifications to the mechanism are warranted. For the most part, the original structure of the Incentive Mechanism has remained intact with cost-effectiveness, net benefits, and financial incentives are still positively correlated.

Since the inception of the Incentive Mechanism, we have increased our CIP efforts and aggressively pursued cost-effective energy conservation through the addition of new technologies and programs, development of trade channels and customer partnerships. We measure and verify direct-savings of all electric and gas programs to reasonably ensure that reported savings are as accurate as possible, while balancing cost.[34]

In 2011, we surpassed the 1.5 percent electric energy savings goal for the first time. In 2016, we proudly reported that we had surpassed it for the sixth consecutive year. The

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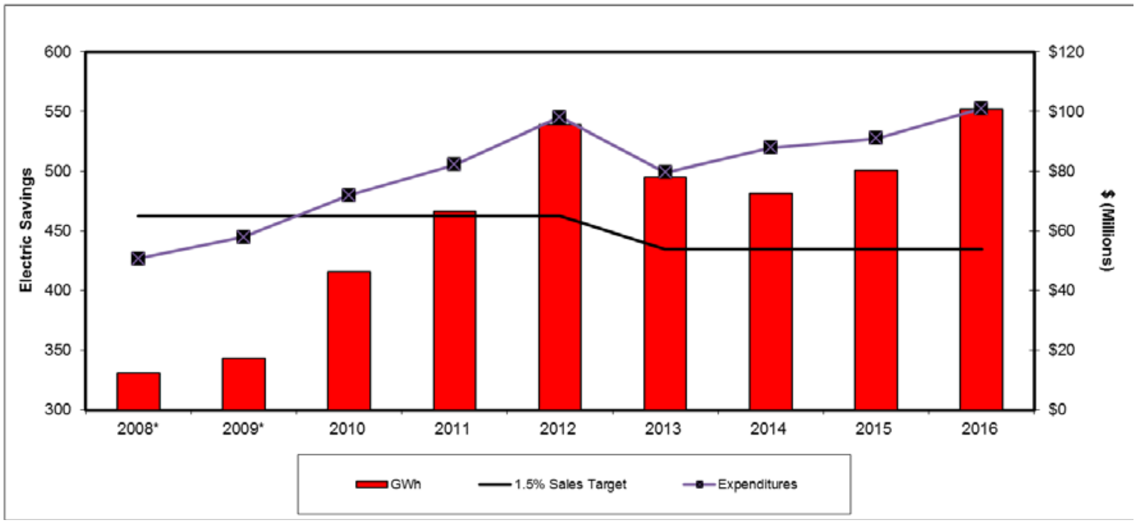
33 Based on a 250 MW medium-sized plant size.

34 At the behest of the Company, program evaluations are conducted by third parties to identify if any modifications or improvements to programs are warranted. Measurement and verification costs and program evaluation costs are included within each triennial plan's budget.

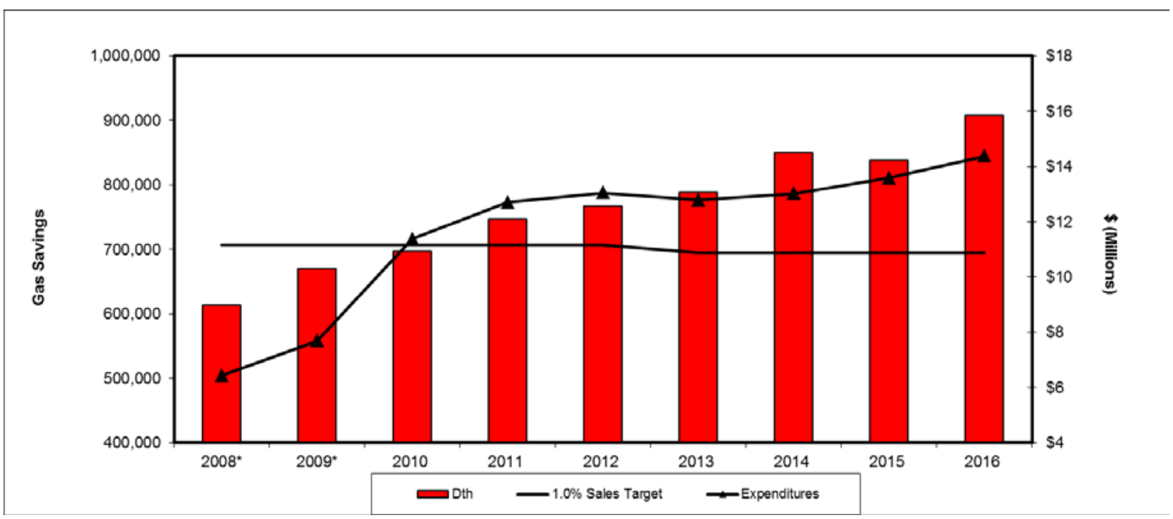
following Figures illustrate our CIP spending and energy savings performance since the inception of the NGEA.

Figure 2 – CIP Electric Savings, Expenditures, and 1.5% Target (2008-2016)



Note: In the 2008 and 2009 plan years, goals were not set as a percent of savings threshold. Therefore, we have set the 2008 and 2009 savings targets equal to the 2010-2012 levels.

Figure 3 – CIP Gas Saving, Expenditures, and 1.0% Target (2008-2016)



Note: In the 2008 and 2009 plan years, goals were not set as a percent of savings threshold. Therefore, we have set the 2008 and 2009 savings targets equal to the 2010-2012 levels.

Even in the face of declining avoided costs and stricter codes, standards and baselines, we have achieved unprecedented levels of energy savings and maintained our strong and long-standing commitment to energy conservation.

As discussed previously, the Commission has also approved a revenue decoupling pilot designed to separate our revenue from changes in our energy sales. When a utility's revenues fluctuate with the amount of energy it sells, a disincentive to promote energy conservation occurs. Revenue decoupling removes this link between a utility's sales and revenues, therefore eliminating the disincentive to promote energy conservation. We submitted our first annual decoupling report in 2017 in Docket Nos. E002/GR-13-868 and E002/GR-15-826 which is pending Commission action at this time. Our filing explains that after the first year of decoupling, residential non-space heating and small commercial & industrial non-demand customers, which make up 97 percent of decoupled customers, will receive a refund. The residential space heating customers were surcharged.

The Incentive Mechanism, with the recent addition of decoupling, ensures the Company is dedicated to cost-effective energy conservation and surpassing its energy savings goals.

2. Renewable Energy Standard

As already discussed, the Minnesota legislature has set specific renewable energy objectives as part of the Minnesota RES. These standards require other utilities to generate at least 25 percent of their total retail electric sales using eligible technologies by 2025. However, the standards hold Xcel Energy to an even higher bar, requiring that we generate at least 30 percent of our total electric retail sales using eligible technologies. We do not view that standard as a ceiling, and are thus committed to continuing to improve our environmental performance in a cost-effective manner.

To that end, we have continued to evaluate and propose wind projects that will result in customer benefits. Indeed, we are the first utility in the nation to have proposed a post-2020, 80 percent PTC wind project – and have done so while achieving a total project cost that is in line with earlier 100 percent PTC projects.[35] Assuming that all 1,850 MW of new wind generation goes into service as proposed, we expect to generate nearly 50 percent of our total retail sales using eligible renewable generation as of 2022. We further expect these projects to result in customer savings of over $1.7 billion on a present-value revenue requirements basis. Thus, while we expect to be in compliance with the RES into the future, we will continue to push further into a position of environmental leadership as long it results in customer benefits.

3. Solar Energy Development

Since the passage of the SES under the 2013 Energy Omnibus Bill, we have grown our utility portfolio of solar resources and expanded access to small-scale solar

[35] *See* Petition, IN THE MATTER OF XCEL ENERGY FOR APPROVAL OF THE ACQUISITION OF 302.4 MW WIND GENERATION, Docket No. E002/ M-17-694 (September 26, 2017).

resources for all customers. The SES requires that by the end of 2020, we generate or procure at least 1.5 percent of our total retail electric sales in Minnesota from solar energy. The SES further requires that at least 10 percent of the 1.5 percent be generated from resources that are 20 kW or less. Finally, the SES includes a goal that by 2030, 10 percent of our total retail electric sales in Minnesota are generated by solar energy.

As of the end of 2017, we have approximately 260 MW of universal-scale solar energy on our system and 12,560 kW of qualifying small solar resources from our Solar*Rewards and Made In Minnesota programs, which we expect will meet our compliance requirements.[36] We additionally offer a Solar*Rewards Community program to customers. As of the end of December 2017, approximately 3,000 customers will be participating in the program, which we anticipate will have over 250 MW of community solar garden capacity.[37]

Also in the community solar garden space, we have demonstrated our commitment to continuous improvement through our voluntarily engaging ICF Resources to conduct a comprehensive analysis of our current interconnection processes and benchmark them against industry best practices. What followed was an intensive review that resulted in 26 specific findings and recommendations which included six categories of process enhancements. We are working to move many of the ICF recommendations off the page and into practice by bringing them forward in the ongoing interconnection docket. We also provide monthly metrics to the Commission on the status of the program.

IV. GRID MODERNIZATION AND EVOLVING CUSTOMER EXPECTATIONS

We also are beginning our transition to a smarter and more modern grid.

As the Commission knows, we are taking a building block approach to introducing grid modernization technologies, focusing first on foundational elements needed to support fundamental applications before enabling more advanced applications. The Commission has certified the first component – the Advanced Distribution Management System – which is now underway. And in our November 1, 2017 Grid Modernization Report, we proposed certification of our first set of advanced functionalities, including: (1) a Time of Use Rate Pilot that relies on Advanced Metering Infrastructure (AMI), and (2) Fault Location, Isolation, and Service

[36] *See* Solar Energy Standard Annual Report, Docket No. E999/M-17-283 (June 1, 2017) for universal-scale solar; *See* Xcel Energy response to MPUC Information Request No. 1, Solar Energy Standard Annual Report, Docket No. E999/M-17-283 (June 19, 2017) for Solar*Rewards and Made In Minnesota small solar.
[37] *See* Monthly Update, Docket No. E002/M-13-867 (December 14, 2017).

Restoration (FLISR), which is a reliability improvement project.[38]

We are also being responsive to the more particularized needs of certain customers. For instance, in November 2015, we proposed a Renewable*Connect Pilot. That program emerged from an extensive stakeholder engagement process, customer surveys, and a panel study. Through those efforts, we were able to learn what customers want in a "green tariff" program. Those learnings informed the key components of the Pilot, including—among other things—that it was a non-subsidized, "pay to play" program where you could pay-as-you go. Customers also articulated a need for price certainty and a desire that the Pilot include both solar and wind resources. We also responded to feedback from the Minnesota Department of Administration and supplemented our Petition in September 2016 – adding an extension to the pilot called Renewable*Connect Government. Through this offering, we will supply renewable energy to the newly renovated State Capitol Building.

Customer interest in EVs is also on the rise and, most recently, we proposed a pilot responsive to customer and stakeholder feedback – both of which indicated that customers were interested in reducing barriers to the cost of adopting EVs, and the Company's time-of-use-based EV rate. We designed the pilot to test the potential for cost savings and customer experience improvements through a combination of new equipment, a monthly equipment charge, and off-peak rate design.

In short, we are passionate about delivering high quality service and developing new products and services that our customers value. We believe that the perspective of our customers is important, and along with public policy goals should help in identifying the targeted performance opportunities that emerge from this proceeding.

V. OPPORTUNITIES TO EXPAND PERFORMANCE METRICS AND/OR INCENTIVES

We believe the Minnesota regulatory construct has worked quite well in recent years, has created positive incentives for utilities, and has resulted in a myriad of benefits for customers. As discussed throughout these Comments, we are aligned with state policy and our customers and perform exceptionally well when it comes to the core of utility regulation—providing service that is safe, reliable, affordable, and environmentally responsible. That said, we recognize there may be opportunities to measure our performance and further our alignment with the public interest in new and different

[38] *See* IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, DOING BUSINESS AS XCEL ENERGY, FOR APPROVAL OF THE 2017 BIENNIAL REPORT – DISTRIBUTION GRID MODERNIZATION, Docket No. E002/M-17-776 (November 1, 2017). *See related* IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, DOING BUSINESS AS XCEL ENERGY, FOR APPROVAL OF A TIME OF USE RATE DESIGN PILOT PROGRAM, Docket No, E002/M-17-775 (November 1, 2017).

ways.

We believe these opportunities are targeted in nature, and we believe it will be important to take a principled, cautious, and deliberate approach that adheres to key design principles recognized among PBR experts as foundational to effective performance regulation. These principles include:

1. *Tied to the policy goal***.** A metric should clearly reflect whether or not the underlying policy goal is being met. That is, it should seek and evaluate data that is specifically tied to the particular policy goal underlying the metric.
2. *Clearly defined***.** The method of calculating a metric should be precise and unambiguous in order to enable meaningful comparisons and to reduce potential disputes.
3. *Able to be quantified using reasonably available data.* Using already reported data or data that is readily available will reduce administrative burden and the costs associated with implementing the metric.
4. *Sufficiently objective and free from external influences.* Metrics should seek to measure behaviors that are within a utility's control and free from exogenous influences, such as weather or market forces.
5. *Easily interpreted.* Metrics should exclude the effects of factors outside a utility's control so they provide a better understanding of utility performance and should use measurement units that facilitate comparisons across time and utilities (i.e., "per KWh" or "per customer")
6. *Easily verified.* Straight-forward data collection and analysis techniques should be used, and independent third-party evaluators can further ensure accurate verification with respect to performance metrics.

In addition to these design principles, we believe the Commission and stakeholders should also consider the potential pitfalls associated with performance metrics, including:

- *Unintended Consequences.* The Commission should carefully consider how certain performance metrics will actually drive utility behavior and how such mechanisms will result in shifting of resources and attention to certain areas of focus and possibly away from others.
- *Regulatory Burden.* Performance incentives can be costly, time-consuming, and a distraction from more important activities—particularly if they do not relate to the core goals of utilty regulation.
- *Uncertainty.* Metrics, targets, and financial consequences that are not clearly defined create uncertainty, introduce contention, and are less likely to achieve policy goals. Likewise, significant or frequent changes to performance metrics

create additional uncertainty for utilities, inhibit efficient utility planning, and encourage utilities to focus on short-term solutions rather than long-term goals.

- *Disproportionality.* Performance incentive mechanisms should not provide rewards or penalties that are too high relative to customer benefits or the utility costs to achieve the desired outcome. Disproportionate results can also occur when the mechanisms based on volatile or uncertain factors that are beyond a utility's control.

Clearly, the identification of a specific policy goal is a critical threshold issue that will enable the Commission to work through both the design principles outlined, above as well as the potential pitfalls associated with adopting any performance metric. Core utility priorities benefit all customers. Before considering more targeted opportunities, it will also be important for the Commission to consider the parties or subsets of customers that will benefit.

That said, we have reflected on potential areas of focus that may be ripe for the development of specific policy goals and the application of additional PBR where the Commission could drive change by encouraging the Company to apply its expertise in new ways. Here are several examples for consideration:

- *Incenting investments and products that help decarbonize other industries.* We believe we may able to harness our experience and record of reducing carbon emissions to help the transportation, or agriculture industries improve their environmental performance. Indeed, we believe we have the ability to impact the progress of electrification, which has the potential to dramatically reduce carbon emissions and the environmental impacts for those industries.
- *Incenting new rates that reduce peak demand or shift load.* While we recently introduced a new TOU pilot, we believe there are opportunities to re-purpose CIP to fund and incent the Company to develop, in conjunction with stakeholder input, next wave rate designs that reduce peak demand or shift load while leveraging new technologies.
- *Measure whether we are improving in interconnecting DG resources.* We took an important step in retaining ICF Resources to study our distribution interconnection practices and recently providing another hosting capacity study which provides greater transparency to third parties about the technical capabilities of our distribution system to support distributed resources. With that being said, we believe there is an opportunity to develop a metric that allows for a transparent assessment of whether we are continuing to make improvements in interconnecting DG resources to our distribution system.

Should the Commission or our stakeholders agree that any of these are an area for potential PBR development, we could provide a more detailed proposal – including a specific policy goal or set of goals and a suite of performance metrics that would be consistent with with the principles outline above – in a later set of comments in this docket.

CONCLUSION

We appreciate the opportunity to provide these comments. We believe Minnesota's current regulatory model is sound, key regulatory outcomes are being achieved, and alternative regulatory tools, including performance based rates are already being employed. That said, we recognize that there are opportunities for the Company to improve performance in new and different ways. We are an engaged partner, and look forward to continued dialogue and a principled approach to further align our actions with policy objectives.

Dated: December 21, 2017

Northern States Power Company

Expert Opinion and Schedules
Dr Mark N. Lowry

Docket No. E002/CI-17-401

December 21, 2017

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS

A. My name is Mark Newton Lowry. I am the President of Pacific Economics Group ("PEG") Research LLC. My business address is 44 East Mifflin Street, Suite 601, on Capitol Square in Madison, Wisconsin.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. PEG Research is a consulting firm that works primarily in the field of utility economics. I manage the company and serve as principal investigator for many of our projects. I have more than thirty years of experience as an industry economist and am internationally recognized for my work in the fields of performance-based regulation ("PBR") and utility performance measurement. I have testified dozens of times on these topics, which share a foundation in economic statistics. The University of Wisconsin trained most of our staff and is renowned for its economic statistics program.

The diverse client base for my PBR work has included regulatory commissions, government agencies, and consumer and environmental groups as well as utilities. For nearly two decades I have advised the Edison Electric Institute ("EEI") on PBR and other new approaches to regulation that are collectively called alternative regulation ("Altreg"). I have prepared several EEI white papers on Altreg and surveys of trends in regulation. In Minnesota I have testified for Fresh Energy. I recently co-authored two white papers on PBR for Lawrence Berkeley National Laboratory and am currently testifying in support of PBR initiatives for the gas and electric services of Public Service of Colorado.

Before joining PEG, I was a Vice President of Christensen Associates in Madison and an Assistant Professor teaching energy economics at the Pennsylvania State University. My resume includes numerous professional publications and public speaking engagements. I have chaired several conferences on Altreg and utility performance measurement. A Cleveland area native, I hold a Ph.D. in applied economics from the University of Wisconsin. Exhibit MNL-1 provides further details of my qualifications.

Q. WHY DID THE COMPANY RETAIN YOU?

A. The Minnesota Public Utilities Commission ("MPUC" or "the Commission") recently approved a multiyear rate plan ("MYRP") for Northern States Power-Minnesota ("NSPM") electric. Minnesota Statute 216B.16, Subd. 19 states, in part, that the Commission may in approving an MYRP "require the utility to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies" and "may initiate a proceeding to determine a set of performance measures that can be used to assess a utility operating under a multiyear rate plan."

The MPUC, in its order approving the Company's plan, found the record in the proceeding insufficient to approve a final set of performance metrics and incentives.[1] In a September Notice of Comment Period, the Commission requested comments from interested parties on "how performance metrics and

[1] MPUC Order, E-002/GR-15-826, p. 23.

standards, and potentially incentives, could further align the focus of [NSPM's] utility management with the public interest."[2]

The first phase of this docket will consider key goals for the utility sector and which metrics or information should be used to determine whether NSPM is meeting those goals. The second phase will consider how performance metrics and standards developed in Phase 1 may be used or applied by the Commission, including possible performance standards, targets, and financial incentives.

My company is a leading North American consultancy in the field of performance-based regulation. NSPM has retained us to appraise its current regulatory system and consider the need for supplemental performance metrics and incentives.

Q. CAN YOU BRIEFLY SUMMARIZE YOUR COMMENTS?

A. I discuss the goals of regulation and regulatory tools that are useful in achieving these goals. There follows an appraisal of the Company's regulatory system and discussions of possible reforms that can strengthen its performance incentives. Exhibit MNL-2, provides a Glossary of Terms. Exhibit MNL-3 details the simple algebra of PBR.

My analysis reveals that various tools are available to regulators to produce good outcomes for utilities, their customers, and society. The toolkit includes revenue decoupling, integrated resource planning, and multiyear rate plans as well as

[2] MPUC, Notice of Comment Period, Docket No. E-002/CI-17-401, p. 1.

performance metric systems. Performance metric systems are a useful part of a regulatory system but must be carefully designed to avoid excessive regulatory burden.

NSPM operates under an unusually sophisticated regulatory system. The careful design of this system reduces the need for new performance metrics and metric-based incentives. There are some new performance dimensions and areas of weak incentives which new performance metrics can address. However, expansion of the NSPM's performance metric system should be careful and methodical. Other regulatory reforms are also available to bolster the Company's incentives.

II. GOALS OF REGULATION

Q. WHAT ARE THE REASONS THAT UTILITIES ARE REGULATED?

A. Utilities provide services that are essential to a modern economy and that are provided most cost effectively by monopolies. In a free market this situation could result in monopolies pricing their services in ways that deny consumers much of the benefit of these services. In Minnesota and many other jurisdictions around the world, governments have responded to this predicament by permitting monopolies but subjecting their terms of service to regulation. Regulation limits utility revenue to compensation for the reasonable cost of utility service. Utilities are obliged to provide service in return for this compensation. Regulation of electric utilities is also needed because the generation of power can involve emissions that damage the environment.

Q. WHAT THEN ARE THE GOALS OF REGULATION?

A. The electric utility industry should provide the largest possible stream of net value. Net value is the difference between benefits and costs of the industry's operations. Electricity provides enormous benefits because it is used ubiquitously every day and is typically available at all times for a reasonable cost. However, the cost is by no means negligible. Additionally, electric services have costs and also some benefits for the environment. There are also safety related costs and the cost of regulation that need to be considered as part of net value. Net value should be shared equitably between utility owners, customers, and other impacted parties. The job of the regulator is to cost-effectively encourage good utility performance and an equitable allocation of the benefits.

Q. WHAT CONSTITUTES GOOD UTILITY PERFORMANCE?

A. Generally speaking, good utility performance is a utility providing affordable, reliable, safe electric service while being a present, good corporate citizen. Naturally, good utility performance will stimulate the regional economy directly and indirectly. Increasingly, good utility performance also includes environmental and economic benefits that result from increasing the number of renewables in a utility's generation fleet and/or providing carbon-free power, as well as, providing more products and solutions which make cost-effective green power directly available to customers.

Q. GOOD UTILITY REGULATION IS SOMETIMES DESCRIBED AS SIMULATING THE OUTCOMES OF COMPETITIVE MARKETS. DO YOU AGREE?

A. Yes. In a well-functioning competitive market, the price of a product reflects the cost of a typical firm, not that of individual suppliers. It also reflects product quality. Suppliers pay for important collateral costs of their operations (e.g., environmental damage) so that there are few externalities.

Competitive markets incentivize suppliers to contain their costs and provide goods and services in the bundles and price/quality combinations that customers want. Suppliers have no preference for capital cost over operation and maintenance ("O&M") expenses. Major steps in the supply chain may be outsourced, including those requiring large physical capital expenditures. Individual suppliers profit from improving performance but competition passes most benefits of industry performance gains to customers in the long run.

The revenue of competitive market suppliers is chiefly compensation for the cost of providing their products. The main "performance" customers pay for is the provision of the product. Superior performance is not required to earn a competitive rate of return.

It should also be noted that suppliers in competitive markets often experience windfall gains and losses. For example, earnings of Minnesota soybean growers are depressed by local hailstorms and raised by a drought in Brazil. A grower with depreciated facilities and equipment receives the same price as one with brand new assets.

Q. WHAT HAS BEEN THE MOST COMMON WAY TO REGULATE UTILITIES?

A. The traditional approach to utility regulation in North America is commonly called cost of service regulation ("COSR"). Under this regulatory system, the base rates that compensate utilities for costs of capital, labor, materials, and services that they use are revised periodically in general rate cases. In each rate case, a revenue requirement is established that compensates the utility for its prudently incurred cost less the other operating revenue that the company receives from miscellaneous non-tariffed services. Costs are sometimes deemed imprudent and disallowed. Recovery of costs that utilities incur to purchase energy commodities (e.g., fuel and purchased power) is often expedited by trackers and riders. Rate designs are expressly approved by the regulator and may reflect a wide range of considerations which include cost causation and appropriate price signals to inform customer usage decisions. Legacy rate designs collect a substantial portion of fixed costs from volumetric and other usage charges.

Q. DO YOU HAVE ANY CRITICISMS OR CONCERNS ABOUT COSR?

A. Yes. COSR is an effective means of providing service through monopolies while ensuring that most cost savings achieved flow to customers. However, accumulating experience with this regulatory system has revealed some limitations. I provided a critique of COSR in my recent white paper for Berkeley Lab which merits summary here. I explained that the regulatory cost of COSR is high for utilities, other stakeholders, and commissions when rate cases are frequent and/or unusually difficult. Commissions understandably take measures to contain regulation's costs which in turn may result in sending a weakened "price signal" to the utility to invest prudently, incur a reasonable level of costs, and to improve operations.

This analysis suggests that the efficacy of COSR varies with the business conditions utilities face. The key business conditions that affect the finances of an electric utility include input price inflation, usage of its system per residential and commercial customer (aka average use), and the need for capital expenditures ("capex") that do not automatically produce revenue. When business conditions are favorable, revenue growth between rate cases roughly matches (and can even exceed) cost growth. Rate cases are then infrequent, regulatory cost is low, and performance incentives can be strong. When conditions are chronically unfavorable, however, cost tends to grow more rapidly than revenue. Utilities respond by filing rate cases more frequently and/or by asking for more expansive cost trackers. Regulatory costs can be high and performance incentives can be diluted under these conditions. Utility performance tends to deteriorate just when better performance is most needed to keep customer bills reasonable.

Q. ARE BUSINESS CONDITIONS FACING ELECTRIC UTILITIES TODAY GENERALLY FAVORABLE OR UNFAVORABLE?.

A. We showed in our most recent white paper for Berkeley Lab that key business conditions facing electric utilities today are considerably less favorable than they were in the decades before 1970 when COSR became a tradition.[3] We call this historical period the "golden age" of COSR.

There has in recent years been mounting concern about the impact of fossil-fueled power generation on the environment. Demand growth has been slowed by large DSM programs in many states and by DGS in a few states such as California and Hawaii. Growth in the usage of power per residential and commercial customer (aka "average use") once grew briskly and, under legacy rate designs, helped utilities self-finance cost growth but is now commonly negative. Some utilities need high levels of capex that don't automatically produce revenue growth.

Q. IS COSR THE ONLY WAY IN WHICH UTILITIES CAN BE REGULATED?

A. No. A number of other tools have been developed in recent decades to regulate utilities, and these can be used to address unfavorable business conditions. For example, revenue decoupling can address declining average use and reduce utility disincentives to embrace demand-side management ("DSM") and distributed generation and storage ("DGS"). Trackers can expedite recovery of volatile or rapidly rising costs of some base rate inputs so that rate cases can occur less frequently. Integrated resource planning, distribution system planning, and clean energy standards can complement prudence reviews as a means of encouraging a sound business plan. PBR can strengthen utility performance incentives and increase the efficiency of regulation.

3 Lowry, M.N., Makos, M., Deason, J., and Schwartz, L., 2017. "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," for Lawrence Berkeley National Laboratory, Grid Modernization Laboratory Consortium, U.S. Department of Energy, https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

III. PERFORMANCE-BASED REGULATION

Q. IS PBR A MONOLITHIC FORM OF REGULATION OR DOES IT CONSIST OF DIFFERENT ELEMENTS?

A. PBR encompasses diverse regulatory tools that include multiyear rate plans, performance metric systems, and incentivized cost trackers. These tools can be and often are used in combination.

A. Multiyear Rate Plans

Q. WHAT ARE THE KEY FEATURES OF THE MYRP APPROACH TO PBR?

A. An MYRP features a moratorium on general rate cases. A four or five-year rate case cycle is common, and due to this length of time, there is often a need to adjust a utility's rates for changing business conditions between rate cases. An attrition relief mechanism ("ARM") permits revenue to grow in the face of cost pressures without closely tracking the cost that the utility actually incurs. Performance incentive mechanisms ("PIMs"), discussed further in the next section, link revenue to the utility's service quality.

A number of other provisions are sometimes added to MYRPs. For example, costs that are difficult to address with an ARM may be addressed separately using trackers and associated rate riders or deferral arrangements. Some costs are typically chosen in advance for tracker treatment. Miscellaneous changes in cost, which are hard to foresee and largely beyond the control of the utility, are also typically tracked when they occur.

Some plans feature an earnings sharing mechanism ("ESM") that shares the surplus or deficit earnings, or both, between utilities and their customers which occur when the utility's rate of return on equity ("ROE") varies from the commission-approved target. Off-ramp mechanisms permit reconsideration and possible suspension of a plan under pre-specified outcomes such as extreme ROEs.

Q. CAN PROVISIONS BE ADDED TO PLANS TO STRENGTHEN UTILITY INCENTIVES TO EMBRACE EFFICIENT DSM AND DGS?

A. Yes. Utility expenditures on DSM programs are commonly tracked. Revenue decoupling and/or lost revenue adjustment mechanisms can reduce the sensitivity of earnings to DSM and DGS. Performance incentive mechanisms can be added to plans which reward utilities for successful DSM programs.

Q. ARE THERE SOME OTHER OPTIONAL PROVISIONS OF MYRPS THAT MERIT NOTE?

A. Yes. Some plans have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services. Utilities may also be permitted (or required) to gradually redesign rates for standard services during the plan in fulfillment of commission-approved goals. For example, default rate designs for residential customers can move towards a time of use pattern.

To reduce regulatory cost and bolster incentives to achieve lasting efficiency gains, plans are sometimes extended or updated without a new rate case. If a rate case does occur, an efficiency carryover mechanism ("ECM") can permit the utility to keep a share of any lasting cost savings that are embodied in the new revenue requirement.

In practice, however, the revenue from an energy utility MYRP typically doesn't vary too far from the utility's cost for an extended period. Utilities aren't the only party to regulation that seeks a cost basis for MYRP rates. For example, consumer groups are customarily wary of letting a utility's revenue fall substantially below its cost for lengthy periods.

Q. ARE MYRPS A RECENT PHENOMENA?

A. NO. MYRPs have been used in U.S. regulation since the 1980s. They were first used on a large scale for railroads and telecommunication carriers.[4] Companies in these industries faced significant competitive challenges and complex, changing customer needs that complicated COSR. MYRPs streamlined regulation and afforded companies in both industries more marketing flexibility and a chance to earn superior returns for superior performance. Both industries achieved rapid productivity growth under MYRPs. Some states still use MYRPs to regulate incumbent local exchange carriers.[5] The Federal Energy Regulation Commission ("FERC") uses MYRPs to regulate oil pipelines.[6]

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[4] US West and successor companies have operated under MYRPs in Minnesota.

[5] See, for example, California Public Utilities Commission, Decision Approving Settlement, Case 13-12-005, Decision 15-10-027, October 2015.

[6] See, for example, Federal Energy Regulatory Commission, Order Establishing Index Level, Five-Year Review of the Oil Pipeline Index, Docket RM15-20-000, December 2015.

MYRPs have also been used to regulate gas and electric utilities.[7] California has used MYRPs since the 1980s. MYRPs became popular in several northeastern states in the 1990s. MYRPs are now a common form of alternative regulation. Use of MYRPs has recently spread to vertically integrated electric utilities ("VIEUs") in diverse states that include Arizona, Colorado, Florida, Virginia, and Washington as well as Minnesota.

MYRPs are even more widely used to regulate Canadian energy utilities. For example, all gas and electric utilities in the Gopher State's neighbor to the north, Ontario, operate under these plans. Overseas, MYRPs are the norm in Australia, Ireland, New Zealand, and the United Kingdom. Great Britain's approach to MYRP design, called "RIIO", has drawn considerable interest in the United States. Countries in continental Europe which use MYRPs include Austria, Germany, Hungary, Lithuania, the Netherlands, Norway, Romania, and Sweden.

Q. ARE MYRPS ALWAYS INITIATED BY UTILITIES?

A. No. Use of MYRPs in some American states (e.g. California and Maine) has been driven by Commissions or lawmakers. In other countries, the impetus for MYRPs has come from the public sector more frequently. For example, provincial law in Quebec requires the Régie de l'Energie to use approaches to regulation for Hydro-Québec, the large VIEU in the province, which streamline regulation, encourage performance gains, and share benefits with customers.[8]

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7 MYRP precedents for gas and electric utilities have been monitored by the Edison Electric Institution in a series of surveys. The latest is Lowry, M., Makos, M., and Waschbusch, G., *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute, November 2015.

8 National Assembly of Québec, 40th legislature, 1st session, Bill n°25 (2013, Chapter 16): An Act respecting mainly the implementation of certain provisions of the Budget Speech of 20 November 2012, Chapter 1, Division 1 as passed June 2013.

The Régie recently ordered Hydro-Québec to operate prospectively under an MYRP for its power distributor services.[9]

Q. WHAT ARE SOME ADVANTAGES OF THE MYRP APPROACH TO REGULATION?

A. Multiyear rate plans have several general advantages over COSR. Utilities have stronger performance incentives and greater operating flexibility so that better performance is encouraged. The strengthened performance incentives and reduced preoccupation with rate cases which MYRPs provide can encourage a more performance-oriented corporate culture. Benefits of better performance can be shared with customers via earnings sharing mechanisms, the occasional rate cases, an efficiency carryover mechanism, and/or careful ARM design.[10]

Q. HOW IS THIS ACCOMPLISHED?

A. The attrition relief mechanism of an MYRP can provide timely rate escalation that permits an extension of the period between rate cases and limited use of cost trackers. Revenue escalation from the ARM is based on a forecast of the utility's cost, industry cost trends, or both, and not on growth in the exact cost that the utility incurs. This increases opportunities for utilities to bolster earnings from efforts to contain growth in the rate base and other costs that are addressed by the ARM (i.e., costs that are not tracked). Loosening the link between a utility's cost and its revenue gives managers an operating environment more like that which their commercial and industrial customers experience. Avoiding a full true up of

[9] Hydro-Québec's generation division already operates under a form of MYRP.

[10] Customers can also benefit from the more predictable rate growth that MYRPs make possible. Rate trajectories can be sculpted to diminish rate bumps.

revenue to the company's cost when the plan expires can magnify the incentive "power" of an MYRP.

To the extent that products and services aren't subject to revenue decoupling, an MYRP can also strengthen incentives to market them effectively since the utility gets to keep the margins that result longer. This is a useful attribute in an era when changing technologies and customer needs create opportunities for new rates and services. Services to price-sensitive, large-volume customers are sometimes exempted from decoupling and the other operating revenues from miscellaneous non-tariffed services frequently are.

MYRPs can also encourage good utility performance by increasing operating flexibility in areas where the need for flexibility is recognized. Reduced rate case frequency and reliance on ARMs for revenue escalation means that the prudence of utility actions must be considered less frequently. Utilities are more at risk from bad outcomes (e.g., needlessly high capex) and can gain more from good outcomes (e.g., relatively low O&M expenses that do not reduce service quality). Knowledge of stronger incentives informs prudence reviews when they are made.

The PIMs included in multiyear rate plans also play a role in encouraging good performance. For example, we have noted that MYRPs can strengthen incentives to contain costs, and these include costs incurred to maintain or improve service quality and safety. In competitive markets, a producer's revenue can fall materially if the quality of its offerings falls below industry norms. Moreover, customers of firms in competitive markets provide no relief if a company's safety problems trigger costly lawsuits. PIMs can keep utilities on the right path by strengthening their incentives to maintain or improve service quality and safety.

Q. CAN MYRPS IMPROVE THE EFFICIENCY OF REGULATION?

A. Yes. Rate cases are less frequent and can be better planned and executed. Fewer costs need to be tracked. Terms of MYRPs can be staggered so that rate cases overlap less. In Minnesota, for example, rate cases for Otter Tail, Minnesota Power, CenterPoint, and the gas and electric services of NSPM could be scheduled to occur in different years. Streamlining the rate escalation chore can free up resources in the regulatory community to more effectively address other important issues. Senior utility managers have more time to attend to their basic business of providing quality service cost-effectively.

Q. DO MYRPS ALSO HAVE SOME NOTEWORTHY DISADVANTAGES?

A. Yes, and these have limited their adoption in the United States.[11] MYRPs are complex regulatory systems that require skills that the regulatory communities in some states do not possess. It can be difficult to design plans that incentivize better performance without undue operating risk. Controversies can arise in plan design. The main source of controversy in a typical proceeding to approve an MYRP is the appropriate attrition relief mechanism. There are opportunities for strategic behavior that erodes potential plan benefits. Concerns like these have prompted many consumer advocates to oppose MYRPs. Since rate cases are still

[11] For further discussion of disadvantages of MYRPs see Costello, K., *Multiyear Rate Plans and the Public Interest*, for National Regulatory Research Institute, October 2016 and Lowry, M. N., and Woolf, T., *Performance-Based Regulation in a High Distributed Energy Resources Future*, for Lawrence Berkeley National Laboratory, January 2016.

held occasionally, utilities may resist innovative but risky business plans that might lead to prudence disallowances. Best practices in the MYRP approach to regulation have evolved to address some of these problems.

B. Performance Metric Systems

Q. TURNING TO PERFORMANCE METRIC SYSTEMS, WHAT ARE THE KEY FEATURES OF THIS FORM OF PBR?

A. Performance metric systems aid measurement of utility performance in areas of special concern to customers and the public.[12] There are typically several metrics in these systems. Targets are established for some metrics, and performance can be gauged by comparing the utility's actual performance against the target for each metric. Metrics and targets provide the basis for PIMs that link utility revenue to measured performance. Performance metric results are sometimes summarized on scorecards that are available to the public.

Q. CAN YOU PROVIDE A FEW EXAMPLES WHERE PERFORMANCE METRIC SYSTEMS ARE USED IN REGULATION?

A. Most MYRPs have service quality PIMs, and many have PIMs for demand-side management. Service quality and demand-side management PIMs are popular nationally even in the absence of such plans. Interest in using performance metrics in utility regulation has been growing in the U.S., spurred in part by the elaborate performance metric system in Britain's "RIIO" approach to energy utility

[12] Areas of concern are called "outputs" in Britain.

regulation. For example, regulators and many stakeholders are concerned today that utilities increase the effectiveness of peak load management to facilitate greater reliance on intermittent renewable resources and contain load-related capex. Regulators in New York and California have added PIMs or other incentives to MYRPs to reward utilities for peak load management and embrace of miscellaneous non-wire alternatives to local investments in the grid. Demand-side management PIMs are evolving to reward a wider range of DSM initiatives. Performance metric systems are expanding to address other new dimensions of performance like the quality of service to DGS customers and the functionality and utilization of AMI.

Q. WHAT ARE SOME ADVANTAGES OF PERFORMANCE METRIC SYSTEMS?

A. Several advantages of performance metric systems merit note.

- Metrics focus utilities on performance dimensions that matter to regulators, customers, and the general public.
- PIMs can strengthen financial incentives for utilities to perform well. Utilities that perform well can garner goodwill from regulators and the public even in the absence of PIMs.
- Metrics and PIMs can target specific areas of performance concern, such as areas where performance incentives are especially weak.
- Metric systems can evolve incrementally and gradually as new performance concerns arise and older concerns recede.
- PIMs can sometimes reduce the need for prudence oversight. For example, PIMs for reliability can reduce the need for formal reviews of reliability during multi-year rate plans.

- Other means of strengthening incentives and/or reducing regulatory cost may be less practical. For example, incentivization of cost trackers can be difficult for costs that are especially volatile. Regulators may balk at implementing some cutting edge MYRP provisions.

Q. DO PERFORMANCE METRIC SYSTEMS ALSO HAVE DISADVANTAGES?

A. Yes. One disadvantage of performance metric systems is that performance is often difficult to measure. Some metrics (e.g., cost, reliability, and peak loads) are quite sensitive to external business conditions and some of these conditions are volatile. The utility is not then fully responsible for apparent failures and successes. Standardized data on metrics and business conditions that affect them are often unavailable for numerous utilities. The impact of external business conditions on performance metrics may be unclear and/or complicated.

It can also be difficult to establish appropriate award/penalty rates for PIMs. The value of performance (e.g., the value of reduced carbon emissions) is sometimes unclear. Even where it is well understood, the share of benefits that utilities should receive may be unclear. Compensation should not exceed that needed to incentivize good behavior. The appropriate PIM may have a nonlinear form, so that award rates rise or fall with measured performance. Incentives generated by PIMs may overlap. Concerns about overpayment for performance have prompted many consumer advocates to oppose PIMs with awards.

Regulators may have difficulty committing long term to a PIM. "Ratcheting" targets to reflect improving performance can weaken incentives.

These disadvantages of performance metric systems have consequences.

- The design and operation of performance metric systems can invite controversy and strategic behavior by parties to regulation. This problem is magnified when metrics are used in PIMs. For example, utilities and other parties to regulation have sometimes disagreed on the load impact of DSM programs that are addressed by PIMs.[13] Awards and penalties have sometimes been disputed when metrics have been influenced by external business conditions.[14] Utilities are more likely to resist PIMs involving penalties and to propose lenient targets, while consumer groups are more likely to resist PIMs involving awards and to propose aggressive targets.
- The incremental regulatory cost of adding new PIMs to a regulatory system can be substantial. A performance metric system can in principle be so large and complex as to constitute an undue administrative burden.
- PIMs can increase utility risk without an appropriate rate of return adjustment.
- Targets, penalties, and rewards may be too high or too low.
- Utilities may be incentivized to focus on performance dimensions that are more quantifiable and neglect dimensions that are less quantifiable but nonetheless worthwhile. For example, they may focus on traditional utility DSM programs rather than market transformation initiatives where the impact of utility actions is less clear. Amongst their DSM programs, utilities may focus on initiatives

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[13] Gold, R., *Penalties in Utility Incentive Mechanisms: A Necessary 'Stick' to Encourage Utility Energy Efficiency?* The Electricity Journal, November 2014, p. 89.
[14] *Ibid*., p. 90.

where savings are easier to measure. For example, they might prefer direct load control (i.e., dispatchable) programs to time variant pricing.

- A focus on *summary* metrics can, on the other hand, encourage utilities to focus too much on what's easy while neglecting more difficult initiatives that are also desirable. For example, they may focus on achieving good reliability on urban circuits and neglect rural circuits that serve few customers.

Q. DO THESE PROS AND CONS AFFECT METRIC SYSTEMS APPROVED IN THE REAL WORLD?

Yes. Here are some ways that approved performance metric systems reflect these considerations.

- PIMs tend to be limited to situations where incentives are weak and performance is important. They also tend to be used where the net increase in regulatory cost is small because PIMs are easy to develop and administer and/or savings on traditional prudence reviews are large. For example, performance metric systems in MYRPs usually have *reliability* metrics but often do not have *cost* metrics since other plan provisions raise concerns about reliability but reduce concerns about cost containment and cost performance appraisals can be complex and controversial. Demand-side management PIMs tend to have lower rewards where the regulatory system includes revenue decoupling.
- Most PIMs for demand-side management involve only awards.[15] New metrics

[15] Gold, R., *Penalties in Utility Incentive Mechanisms: A Necessary 'Stick' to Encourage Utility Energy Efficiency?* The Electricity Journal, November 2014, p. 89.

- and metrics that are difficult for utilities to control are less likely to be linked to penalties.
- Awards and penalties are often small, and rewards may be arbitrarily capped.
- Some metrics in performance metric systems have targets but no PIMs. Some metrics have neither targets nor PIMs.
- Complex calculations are often eschewed. For example, California's Public Utilities Commission has abandoned the shared savings approach to the calculation of awards for DSM programs. DSM expenditures are amortized in several states.
- Some PIMs have deadbands or Z factors to reduce the impact on awards and penalties of volatile external business conditions. For example, many reliability metrics exclude major event days that are typically the result of unusually severe weather.
- Targets (e.g., those for reliability metrics) are often company-specific and not based on operations of other utilities.

Q. HAVE YOU PERUSED THE DISCUSSION OF PERFORMANCE METRIC SYSTEMS IN THE REPORTS OF THE E21 WORKING GROUP?

A. Yes. e21 is a collaborative initiative convened to explore new approaches to Minnesota electric utility regulation which better align utility earnings with public policy goals. PBR has been a central focus of the initiative. A white paper on a "performance-based compensation framework" was released as part of the

December 2016 Phase II report.[16]

The central vision of the authors of this paper is that a more incentivized regulatory system would strengthen utility incentives to contain cost and provide customers with more service options. Reducing the incentive to grow rate base is a central concern.

The authors envision a transition to a regulatory system that increasingly relies on PIMs to compensate utilities for their services. In the authors' words, a big goal of the proposed reform is to

> Shift away from a regulatory system that rewards the sale of electricity and building large, capital-intensive power plants and other facilities toward one that reasonably compensates utilities for achieving an agreed-upon set of performance outcomes that the public and customers want.

Revenue would eventually be entirely performance-based but nonetheless afford utilities reasonable compensation for the cost of their services. Utilities would have substantially greater opportunities to earn margins from non-traditional rates and services, and this would reduce the revenue requirement for tariffed services.

Q. WHAT IS YOUR VIEW OF THIS PBR PROPOSAL?

A. As a long-time advocate of PBR, I appreciate the work of the e21 Initiative to advance its use and adapt it to new regulatory challenges. However, the respective roles of the MYRP and PIMs in the proposed regulatory system are not clear, and this matters in the context of the instant proceeding. The authors do seem to

[16] e21 Initiative, Phase II Report, *On implementing a framework for a 21st century electric system in Minnesota,* December 2016. http://www.betterenergy.org/e21-PhaseII

embrace the MYRP concept, stating on page 30 of their paper that "a multi-year rate plan fits very well with a more performance-oriented regulatory framework." Several advantages of MYRPs are discussed. When discussing the need for incentives to contain O&M expenses, the authors note on p. 42 that

> this outcome should be achieved through the overall design of a performance-based multi-year rate plan, such as through a stay-out provision (an agreement to stay out of the rate revision process for a given length of time) and tying [O&M] expenses to an inflation index.

However, the discussion elsewhere in the paper suggests that intensification of performance incentives would be achieved principally through new and stronger PIMs. For example, the authors state on p. 33 that "this shift will be driven by more directly tying a portion of utility earnings to performance that is quantifiable, verifiable, and aligned with e21's guiding principles."

This notion is controversial for several reasons. First, the principal performance of an electric utility is the provision of power at the times and places at which customers demand it. And the principal way to "reward" the utility for performing is payment to the utility. I acknowledge that ratepayers want this payment to be as low as practicable and further it is reasonable to adjust the payment to reflect unusually high or low service quality, or for miscellaneous other considerations. However, payment should chiefly be a matter of compensation for efficiently-incurred cost.

Compensation for the cost of electric service provision can be incentivized to encourage cost containment in various ways. MYRPs are a salient means of incentivizing containment of both capex and O&M expenses. Cost containment incentives can also in principal be bolstered by cost management PIMs. These options are traced mathematically in Exhibit MNL-3.

The design of a cost management PIM can involve many of the same complications encountered in designing an attrition relief mechanism. Most MYRPs do not have cost management PIMs. It does not make sense to *overpay* for non-cost performance dimensions as a means of strengthening capex containment incentives.

In my opinion, MYRPs are the core of a state of the art regulatory system. These plans usually contain performance metric systems with several PIMs. Most regulators who have taken the lead in adopting "utility of the future" PIMs (e.g., California, New York, and Britain) are MYRP practitioners. Performance metric systems should be designed to complement – not replace – other parts of a utility's regulatory system such as MYRPs and incentivized cost trackers.

Q. SOME OF THE RECENT INTEREST IN PIMS HAS BEEN KINDLED BY BRITAIN'S RIIO APPROACH TO REGULATION. CAN YOU BRIEFLY EXPLAIN RIIO?

A. Certainly. Since the privatization of British energy utilities in the 1990s British regulation has featured MYRPs called price controls. Revenue escalation has been based on multiyear cost forecasts with updates for inflation. Ofgem has refined various features of the MYRPs over the years in its periodic price control reviews. These refinements have included the addition of several performance metrics and PIMs. Ofgem undertook a particularly substantial review of its regulatory practices beginning in 2008. This review led to the adoption of RIIO, which stands for Revenue = Incentives + Innovation + Outputs.

The RIIO framework should be viewed as an evolution of the previous system wherein many features of earlier frameworks were kept, albeit with some changes. The attrition relief mechanisms in the MYRPs continue to be revenue caps based on cost forecasts approved by Ofgem and indexed to inflation. The terms of the MYRPs were lengthened from 5 years to 8. The use of performance metrics was maintained, with updated targets and some new metrics and incentive mechanisms. Revenue decoupling was also continued.

The "outputs" term of the RIIO acronym refers to a focus on results in a range of performance areas. An elaborate performance metric system is used to monitor outputs and measure performance. Several metrics are used in PIMs. Some outputs are addressed by other ratemaking treatments such as cost trackers, reputational incentives, and discretionary incentives.

Outputs are established in six non-cost performance areas: safety, environmental impact, customer satisfaction, social obligations, connections, and reliability. Ofgem has divided these outputs into "primary" and "secondary" outputs. Primary outputs have a direct impact on customers. Secondary outputs shed light on how primary outputs are achieved. Companies can propose additional metrics in their business plans. Numerous metrics are used to measure outputs, but some outputs are not quantified. Many metrics in RIIO performance metric systems have no PIM.

While non-cost performance receives considerable attention in RIIO, other aspects of these plans such as the design of attrition relief mechanisms command a great deal of the British regulator's attention. Ratemaking tools used to address cost performance include a complicated PIM called the information quality incentive ("IQI"). The IQI encourages utilities to provide honest forecasts of their total expenditures ("totex") and permits utilities to share in the benefits of better cost performance. A substantial portion of ROE is at risk in the RIIO system. However, the big weights in the RIIO PIMs are on reliability and the information quality incentive.

Q. SHOULD THE COMMISSION ASPIRE TO A BRITISH-STYLE REGULATORY SYSTEM FOR NSP?

A. No. This Commission has sensibly approved a first-generation MYRP for the Company that is appropriate for a vertically integrated American electric utility. This approach can be refined over time with upgrades that include an improved performance metric system. British regulation should always be monitored for good ideas but need not be a template for Minnesota utilities.

IV. APPLICATION TO NSPM

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section considers the need to monitor the performance of NSPM and strengthen the Company's performance incentives. I begin with a review of the Company's current regulatory system and performance. There follow discussions of incentive "holes" and possible remedies that include an expanded performance metric system.

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S REGULATORY SYSTEM.

A. NSPM operates under a complex regulatory system that includes a multiyear rate plan and a performance metric system with service quality and demand-side management PIMs. Many other metrics on the Company's operations are routinely reported to the Commission or federal agencies. Revenue decoupling is employed to reduce the sensitivity of revenue to DSM. The Company's resource strategy is constrained by integrated resource planning and renewable energy and DSM standards.

Q. WHAT PROVISIONS OF NSPM'S REGULATORY SYSTEM ARE IN YOUR VIEW ESPECIALLY IMPORTANT IN APPRAISING ITS EFFECTIVENESS?

A. From my perspective, there are several aspects of the regulatory system that make it effective.

First is the multiyear rate plan approved earlier this year which contains many of the key elements I described earlier. The plan spans the four years from 2017 to 2020. The Company cannot file another rate case until November 2019.

The attrition relief mechanism in the plan is a predetermined schedule of gradual rate increases that are based chiefly on forecasts of the Company's costs. The plan does not contain an earnings sharing or off-ramp mechanism. However, a Capital Projects True-Up provides customers with a refund if the Company's actual capital-projects costs are lower than those in rates.

The Company is allowed to continue using previously-approved rate riders. However, NSPM is not allowed to use any new rider during the plan even if new riders are authorized by the legislature.

The regulatory system also contains a comprehensive performance metric system focused on customer service and reliability. Integrated resource planning and careful oversight of rate designs round out the picture.

Q. PLEASE DISCUSS NSPM'S PERFORMANCE METRIC SYSTEM.

A. All Minnesota electric utilities are subject to extensive reporting requirements under Minn. R. 7826 regarding safety, reliability billing accuracy, responsiveness, customer satisfaction, and customer protections. The Company's previously-approved Quality of Service Plan ("QSP") Tariff continues. This is a performance metric system with 10 PIMs for electric services which together address reliability, customer complaints, call response time, invoice accuracy, and invoice adjustment timeliness. These PIMs asymmetrically exact penalties for substandard performance but cannot reward NSPM for good performance. In addition to the service quality PIMs, the Company is required to report data on supplemental metrics that include SAIDI and SAIFI by work center, customer complaints to the commission by category, the number of customers that qualified for outage credits and the amount of credits provided, and information on municipal pumping outages.

The Company also routinely reports a wide variety of additional metrics. For example, a Meter Data Malfunctions tariff prescribes timelines for investigation and remediation of malfunctioning meters, with penalties in the form of limiting NSPM's ability to bill customers any under-billing amounts if they don't meet the timelines. Regarding worker safety, the Company files annual reports to OHSA and the Minnesota Department of Labor which itemize all incidents requiring medical attention or involving property damage resulting in compensation.

Q. PLEASE DISCUSS IN MORE DETAIL PROVISIONS OF THE REGULATORY SYSTEM THAT ENCOURAGE THE COMPANY TO EMBRACE DSM AND RENEWABLE ENERGY.

A. A previously approved full revenue decoupling mechanism continues for most services to small-volume customers. The residential electric vehicle service rate is excluded from the decoupling mechanism. In addition, there are sales forecast true ups for rate classes that are not decoupled.

Each regulated electric utility in Minnesota is required to make annual investments and expenditures in cost-effective energy conservation. The CIP also includes a Financial Incentive Mechanism that encourages utilities to pursue conservation.

Minnesota favors conservation over the addition of new resources and the use of renewable energy when new power supplies are needed. Each Minnesota utility must obtain approval from the MPUC of a 15-year advance integrated resource plan ("IRP"). The next integrated resource plan will be filed during the term of the MYRP.

Q. HAS THE COMPANY'S REGULATORY SYSTEM PRODUCED SOME GOOD RESULTS?

A. Yes. NSPM has achieved some notable performance outcomes under its regulatory system. Some of these are discussed in the Company's submission. I provide here commentary on clean energy initiatives.

NSPM has long demonstrated a commitment to cost-effective DSM, and it has been publicly recognized for its achievements on multiple occasions.[17] The Company currently operates under a 2017-2019 Triennial MNCIP plan approved by the Minnesota Department of Commerce. In 2016 NSP achieved savings equal to 1.91 percent of electricity sales, surpassing the state's 1.5 percent target for the fifth year in a row, and also registered roughly 136 MW in demand savings.[18] In addition to large energy efficiency programs there are several dispatchable load programs.

NSPM's current resource mix includes an array of clean energy resources from its investments and power purchase agreements. In 2016, renewable energy represented a substantial 26% of the generation on the NSP System, (up from 23% in 2015), with over half this amount deriving from wind resources.[19] Meanwhile, the share of nuclear generation rose from 27% to 30%.[20] The Company's latest IRP is expected to reduce carbon emissions roughly 60% by 2030 through a mix of incremental energy efficiency, wind and solar generation, and coal plant

[17] Docket No. E,G002/CIP-16-115, 2017/2018/2019 Minnesota Electric and Natural Gas Conservation Improvement Program Compliance Filing Update (Dec. 30, 2016), p. 4.
[18] Docket No. E,G002/CIP-12-447, 2016 Status Report & Associated Compliance Filings: Minnesota Electric and Natural Gas Conservation Improvement Program (April 3, 2017), p. 1.
[19] NSP-MN and NSP-WI jointly operate the NSP System.
[20] Xcel Form 10-K for the fiscal year ended December 31, 2016.

retirements. The community solar garden program is the largest of its kind in the country. This IRP, which was lauded by environmental groups upon its approval in late 2016, also requires an additional 400 MW of demand response by 2023, and directs the company to consider in its next IRP filing the feasibility of adding a further 1,000 MW of demand response by 2025.[21,22]

With respect to distribution system planning, NSP envisions widespread deployment of Advanced Metering Infrastructure ("AMI") and efforts to enhance interoperability between customer meters, distributed generation, storage, microgrids, and other technologies.[23] As required by Subdivision 8 of the same statute, the Company has made progress in facilitating the integration of additional small-scale distributed generation by more accurately identifying the hosting capacity of individual distribution feeders, and by making this information accessible to developers.[24]

NSPM's default rates for residential customers feature a monthly customer charge of $8 (or $10 for underground line service) and a volumetric charge. The volumetric charge has separate summer and non-summer rates, with the highest rate occurring during the summer months.

[21] Docket No. E-002/RP-15-21, Order (Jan. 11, 2017).
[22] Public Utilities Commission Unanimously Approves Xcel's 15-year Energy Plan, Sierra Club, Press Release (October 13, 2016). Retrieved from: http://content.sierraclub.org/press-releases/2016/10/public-utilities-commission-unanimously-approves-xcels-15-year-energy-plan
[23] Docket No. E002/M-17-776, 2017 Biennial Report on Distribution Grid Modernization (Nov. 1, 2017).
[24] Docket No. E002/M-17-777, 2017 Distribution System Hosting Capacity Study (Nov. 1, 2017).

NSPM's default rate for commercial customers with loads under 25 KW is Small General Service. This has a two-part rate with customer and volumetric charges. Customers taking direct current service also have a demand charge. The volumetric charge has separate summer and non-summer rates, with the highest rate occurring during the summer months.

The Company's default rate for commercial customers with loads of 25 KW or greater is General Service, which is a three-part rate with customer, volumetric energy charges, and seasonal demand charges. The demand charge has separate summer and non-summer rates, with the highest rate occurring during the summer months.

In addition to the default rates the Company provides several additional rate options. These include time of day pricing for all customers, demand response rates, economic development riders, and green power riders. A time-varying rate for residential electric vehicle charging was mandated by Minnesota law.[25] The Company offers two green power riders and an EV charging rate.

Q. DOES NSPM'S REGULATORY SYSTEM NEED ADDITIONAL PERFORMANCE METRICS AND/OR INCENTIVES TO IMPROVE THE COMPANY'S PERFORMANCE?

A. After reviewing NSPM's regulatory system, I conclude that it encourages cost containment and a large role for DSM and renewable resources in the Company's resource strategy. The system also encourages NSPM to promote electric vehicles

[25] Minnesota Statutes, 216B.1614.

and bolster other operating revenue from non-tariffed services. Few regulatory systems for VIEUs in the United States are comparably sophisticated. Regulation of NSPM is headed in the right direction and sweeping change is not warranted at this time.

Q. WITH THAT BEING SAID, ARE THERE OPPORTUNITIES TO EXPLORE THE USE OF PERFORMANCE METRICS AND/OR INCENTIVES?

A. Yes. Notwithstanding the thoughtful design of the Company's regulatory system there are still some performance concerns, due in part to incentive "holes," which metrics can address. I begin by noting that the ability of the current MYRP to incentivize good performance is limited due in part to the fact that it is a first-generation plan that provides a gradual transition to a new form of regulation. The term of the plan is only four years. Innovative strategies for solving problems may in some cases be discouraged by a fear of future prudence reviews. There is no plan extension option or efficiency carryover mechanism to encourage long-term performance gains. There are no performance metrics or PIMs for worker safety or customer satisfaction.

Trackers for energy expenses and transmission costs weaken incentives to contain these costs, although TCR rider recovery is limited to the Company's initial construction bid plus annual cost escalation. The Capital Projects True-Up protects customers from an overly generous ARM but, together with the property tax true up, weakens the Company's incentive to contain other kinds of capex.

Some costs and benefits of NSPM's operations are still largely external. For example, the Company does not increase earnings by purchasing more power from renewable resources in its service territory even though these purchases are good for the environment and stimulate local employment.

The current decoupling system discourages some desirable expansions of NSPM products and services. For example, the Company cannot bolster its earnings by promoting green power and encouraging cleaner electric alternatives (e.g., high efficiency heat pumps and water heaters) to many kinds of fossil-fueled equipment.

The MNCIP Financial Incentive Mechanism chiefly rewards utility conservation programs. There are no awards for various peak load management and market transformation initiatives. Section 216B.1611 Subdivision 2(b) of the Minnesota Statutes states that "The commission may develop financial incentives based on a public utility's performance in encouraging residential and small business customers to participate in on-site generation." However, no such mechanisms have been approved.

Q. PLEASE PROVIDE SOME EXAMPLES OF NEW PERFORMANCE METRICS THAT COULD BE CONSIDERED.

A. Expansion of the performance metric system is one way to monitor the Company's performance under the MYRP and encourage better performance. Here are some areas where our analysis suggests that expansion may be worthwhile.

- The MNCIP Financial Incentive Mechanism can be expanded to reward the Company for a wider range of initiatives to contain peak load. Benefits of peak load management to the distribution system can be considered in the calculation of net benefits. For energy efficiency and peak load management alike, experimentation with "outcome-based" metrics like the trend in the weather-normalized system peak load should be considered as an addition to the current "program-based" metrics.[26]

- Diffusion of distributed generation and storage on NSPM's system should be closely monitored. Pertinent metrics include the number of DGS assets owned by customers and the Company, DGS sales volumes, the quality of DGS customer service, and net benefits of DGS.
- Experimentation is warranted with PIMs for the use of DSM and DGS in select local areas where transmission and distribution capex can be avoided.
- The functionality and utilization of AMI and other smart grid facilities can be monitored with metrics as they are installed. Relevant concerns include the accuracy of AMI and the share of AMI customers who access the web portal and use time-sensitive rates. The Company has stated that performance metrics or improvements associated with grid modernization investments should be examined in the context of the specific proposed investment.
- NSPM's progress in encouraging beneficial electrification and the adoption of special green power packages should be monitored and possibly rewarded with PIMs.
- The environmental footprint of the Company's own operations should be monitored but probably does not warrant PIMs. Possible metrics include the

[26] Outcome-based metrics and PIMs have been approved for use in New York. See, for example, the PIMs approved for a Consolidated Edison multiyear rate plan in Case 16-E-0060, January 2017.

extent of reliance on clean energy resources and estimated carbon emissions from the Company's vehicle fleet.

Q. CAN INCENTIVES ALSO BE STRENGTHENED BY IMPROVING THE MYRP CONSTRUCT?

A. Yes. The MYRP can be revised in several ways to strengthen performance incentives. In the short term, the current plan could be extended. Previously approved trackers can be redesigned to provide more cost containment incentives. For example, NSPM could be permitted to share in the deviation of sales for resale margins from forecasts.

In future plans, the Commission may wish to consider scaling back the Capital Projects True Up to strengthen NSPM's incentive to contain generation and distribution capex. The Company could be provided with a window to seek advanced approval and possible supplemental funding for innovative and risky business strategies. Other MYRP incentive upgrades that merit consideration in future plans include a longer plan term, a plan extension option, and the addition of an efficiency carryover mechanism.

An ECM permits a utility to "carry over" to future plans a portion of lasting performance gains that it achieves. This rewards the utility for achieving lasting performance gains and helps ensure that customers benefit from plans. Our research for Berkeley Lab suggests that the incentive benefits of ECMs can be substantial, especially in MYRPs with shorter terms.

A well-designed ECM focuses on the value to customers of the revenue requirement in the next plan. The focus is often on the revenue requirement for the test year in the rate case that establishes rates for the first year of the next plan. Performance can be measured by comparing this revenue requirement to a benchmark. The benchmark can be based on statistical benchmarking or the ARM from the expiring MYRP.

Q. ARE THERE OTHER WAYS TO IMPROVE THE COMPANY'S PERFORMANCE INCENTIVES?

A. Yes. For example, estimated loads from beneficial electrification can be exempted from decoupling and the sales forecast true up. This would permit the Company to keep margins from beneficial electrification loads exceeding forecasted levels between rate cases.

NSPM can be afforded more opportunities to invest in assets that directly or indirectly reduce negative environmental impacts of its operations and bolster positive impacts such as higher service territory employment. In addition to the ownership of utility-scale renewable generation and AMI, which is already permitted, such opportunities include the ownership, operation, and leasing of distributed and utility-scale storage, distributed generation, EV chargers, and beneficial electrification equipment (e.g., high efficiency heat pump leasing).

V. CONCLUSION

Q. ARE THERE ANY CLOSING COMMENTS YOU WOULD LIKE TO PROVIDE?

A. Yes. Regulation should maximize the net value of utility operations and allocate the value stream fairly. The net value depends critically on the cost of service provision, including environmental impacts. Safety, the cost of regulation, and service territory employment are also salient considerations. Equitable allocation of the value stream involves limiting utility revenue to compensation for its cost, but linking revenue too closely to the utility's own cost weakens performance incentives.

Various tools are available to regulators to produce good outcomes. The toolkit includes periodic rate cases with prudence reviews, revenue decoupling, careful control of rate designs, integrated resource planning, clean energy standards, multiyear rate plans, and performance metric systems. Performance metric systems are an essential part of the mix but must be carefully designed to avoid undue regulatory burden. The appropriate performance metric system depends greatly on other features of a utility's regulatory system.

NSPM operates under an unusually sophisticated regulatory system that includes a multiyear rate plan, revenue decoupling, and a performance metric system. The Company is also subject to integrated resource planning and clean energy standards. Cost effective DSM and utility-scale renewables have been aggressively embraced. Rate designs are closely and thoughtfully regulated. The careful design of this regulatory system reduces the need for new performance metrics and PIMs.

There are some new performance dimensions and areas of weak incentives which new performance metrics can address. Expansion of the performance metric system should nonetheless be careful and methodical. Other regulatory reforms are also available to bolster NSPM's incentives.

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BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Applied Economics, University of Wisconsin-Madison, May 1984

Relevant Work Experience, Primary Positions

Present Position
President, Pacific Economics Group Research LLC, Madison WI
Chief executive and owner of a consulting firm in the field of utility economics. Leads internationally recognized practice in performance-based regulation and utility performance research. Duties include project management and expert witness testimony.

October 1998-February 2009
Partner, Pacific Economics Group, Madison, WI
Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

January 1993-October 1998 **Vice President**
January 1989-December 1992 **Senior Economist, Christensen Associates, Madison, WI**
Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility Altreg and benchmarking.

Aug. 1984-Dec. 1988 **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**
Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Research specialty: role of storage in commodity markets.

August 1983-July 1984 **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**
Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 **Research Assistant to Dr. Peter Helmberger, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

March 1981-March 1982 **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

- Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.
- Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in metal markets.

<u>Major Consulting Projects</u>

1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
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2. Review of Energy, Foresight, and Strategy, Thomas Sargent, ed. (Baltimore: Resources for the Future, 1985). Energy Journal 6 (4), 1986.
3. The Changing Role of the United States in World Mineral Trade in W.R. Bush, editor, The Economics of Internationally Traded Minerals. (Littleton, CO: Society of Mining Engineers, 1986).
4. Assessing Metals Demand in Less Developed Countries: Another Look at the Leapfrog Effect. Materials and Society 10 (3), 1986.
5. Modeling the Convenience Yield from Precautionary Storage of Refined Oil Products (with junior author Bok Jae Lee) in John Rowse, ed. World Energy Markets: Coping with Instability (Calgary, AL: Friesen Printers, 1987).
6. Pricing and Storage of Field Crops: A Quarterly Model Applied to Soybeans (with junior authors Joseph Glauber, Mario Miranda, and Peter Helmberger). American Journal of Agricultural Economics 69 (4), November 1987.
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10. A Competitive Model of Primary Sector Storage of Refined Oil Products. July 1987, Resources and Energy 10 (2) 1988.
11. Modeling the Convenience Yield from Precautionary Storage: The Case of Distillate Fuel Oil. Energy Economics 10 (4) 1988.
12. Speculative Stocks and Working Stocks. Economic Letters 28 1988.
13. Theory of Pricing and Storage of Field Crops With an Application to Soybeans [with Joseph Glauber (senior author), Mario Miranda, and Peter Helmberger]. University of Wisconsin-Madison College of Agricultural and Life Sciences Research Report no. R3421, 1988.
14. Competitive Speculative Storage and the Cost of Petroleum Supply. The Energy Journal 10 (1) 1989.
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20. A Price Cap Designers Handbook (with Lawrence Kaufmann). (Washington: Edison Electric Institute, 1995.)
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23. Forecasting the Productivity Growth of Natural Gas Distributors (with Lawrence Kaufmann). AGA Forecasting Review, Vol. 5, March 1996.
24. Branding Electric Utility Products: Analysis and Experience in Regulated Industries (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1997.
25. Price Cap Regulation for Power Distribution (with Larry Kaufmann), Washington: Edison Electric Institute, 1998.
26. Controlling for Cross-Subsidization in Electric Utility Regulation (with Lawrence Kaufmann), Washington: Edison Electric Institute, 1998.
27. The Cost Structure of Power Distribution with Implications for Public Policy (with Lawrence Kaufmann), Washington: Edison Electric Institute 1999.
28. Price Caps for Distribution Service: Do They Make Sense? (with Eric Ackerman and Lawrence Kaufmann), Edison Times, 1999.
29. "Performance-Based Regulation for Energy Utilities (with Lawrence Kaufmann)," Energy Law Journal, Fall 2002.
30. "Performance-Based Regulation and Business Strategy" (with Lawrence Kaufmann), Natural Gas and Electricity, February 2003
31. "Performance-Based Regulation and Energy Utility Business Strategy (With Lawrence Kaufmann), in Natural Gas and Electric Power Industries Analysis 2003, Houston: Financial Communications, Forthcoming.
32. "Performance-Based Regulation Developments for Gas Utilities (with Lawrence Kaufmann), Natural Gas and Electricity, April 2004.
33. "Alternative Regulation, Benchmarking, and Efficient Diversification" (with Lullit Getachew), PEG Working Paper, November 2004.
34. "Econometric Cost Benchmarking of Power Distribution Cost" (with Lullit Getachew and David Hovde), Energy Journal, July 2005.
35. "Assessing Rate Trends of U.S. Electric Utilities", Edison Electric Institute, January 2006.
36. "Alternative Regulation for North American Electric Utilities" (With Lawrence Kaufmann), Electricity Journal, July 2006.
37. "Regulation of Gas Distributors with Declining Use Per Customer" USAEE Dialogue August 2006.
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40. "Price Control Regulation in North America: Role of Indexing and Benchmarking", Electricity Journal, January 2009

41. "Statistical Benchmarking in Utility Regulation: Role, Standards and Methods," (with Lullit Getachew), Energy Policy, 2009.
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43. "The Economics and Regulation of Power Transmission and Distribution: The Developed World Case" (with Lullit Getachew), in Lester C. Hunt and Joanne Evans, eds., International Handbook on the Economics of Energy, 2009.
44. "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry" (With Lullit Getachew), Review of Network Economics, December 2009
45. "Forward Test Years for US Electric Utilities" (With David Hovde, Lullit Getachew, and Matt Makos),
    Edison Electric Institute, August 2010.
46. "Innovative Regulation: A Survey of Remedies for Regulatory Lag" (With Matt Makos and Gentry Johnson), Edison Electric Institute, April 2011.
47. "Alternative Regulation for Evolving Utility Challenges: An Updated Survey" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, 2013.
48. "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (With Matthew Makos and Gretchen Waschbusch), Edison Electric Institute, November 2015.
49. "Performance-Based Regulation in a High Distributed Energy Resources Future," (With Tim Woolf), Lawrence Berkeley National Laboratory, January 2016.
50. "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," (With Jeff Deason and Matthew Makos), Lawrence Berkeley National Laboratory, July 2017.

Conference Presentations

1. American Institute of Mining Engineering, New Orleans LA, March 1986
2. International Association of Energy Economists, Calgary AL, July 1987
3. American Agricultural Economics Association, Knoxville TN, August 1988
4. Association d'Econometrie Appliqué, Washington DC, October 1988
5. Electric Council of New England, Boston MA, November 1989
6. Electric Power Research Institute, Milwaukee WI, May 1990
7. New York State Energy Office, Saratoga Springs NY, October 1990
8. National Association of Regulatory Utility Commissioners, Columbus OH, September 1992
9. Midwest Gas Association, Aspen, CO, October 1993
10. National Association of Regulatory Utility Commissioners, Williamsburg VA, January 1994
11. National Association of Regulatory Utility Commissioners, Kalispell MT, May 1994
12. Edison Electric Institute, Washington DC, March 1995
13. National Association of Regulatory Utility Commissioners, Orlando FL, March 1995
14. Illinois Commerce Commission, St. Charles IL, June 1995
15. Michigan State University Public Utilities Institute, Williamsburg VA, December 1996
16. Edison Electric Institute, Washington DC, December 1995
17. IBC Conferences, San Francisco CA, April 1996
18. AIC Conferences, Orlando FL, April 1996
19. IBC Conferences, San Antonio TX, June 1996
20. American Gas Association, Arlington VA, July 1996
21. IBC Conferences, Washington DC, October 1996
22. Center for Regulatory Studies, Springfield IL, December 1996

23. Michigan State University Public Utilities Institute, Williamsburg VA, December 1996
24. IBC Conferences, Houston TX, January 1997
25. Michigan State University Public Utilities Institute, Edmonton AL, July 1997
26. American Gas Association, Edison Electric Institute, Advanced Public Utility Accounting School, Irving TX, Sept. 1997
27. American Gas Association, Washington DC [national telecast], September 1997
28. Infocast, Miami Beach FL, Oct. 1997
29. Edison Electric Institute, Arlington VA, March 1998
30. Electric Utility Consultants, Denver CO, April 1998
31. University of Indiana, Indianapolis IN, August 1998
32. Edison Electric Institute, Newport RI, September 1998
33. University of Southern California, Los Angeles CA, April 1999
34. Edison Electric Institute, Indianapolis, IN, August 1999
35. IBC Conferences, Washington, DC, February 2000
36. Center for Business Intelligence, Miami, FL, March 2000
37. Edison Electric Institute, San Antonio TX, April 2000
38. Infocast, Chicago IL, July 2000 [Conference chair]
39. Edison Electric Institute, July 2000
40. IOU-EDA, Brewster MA, July 2000
41. Infocast, Washington DC, October 2000
42. Wisconsin Public Utility Institute, Madison WI, November 2000
43. Infocast, Boston MA, March 2001 [Conference chair]
44. Florida 2000 Commission, Tampa FL, August 2001
45. Infocast, Washington DC, December 2001 [Conference chair]
46. Canadian Gas Association, Toronto ON, March 2002
47. Canadian Electricity Association, Whistler BC, May 2002
48. Canadian Electricity Association, Montreal PQ, September 2002
49. Ontario Energy Association, Toronto ON, November 2002
50. Canadian Gas Association, Toronto ON, February 2003
51. Louisiana Public Service Commission, Baton Rouge LA, February 2003
52. CAMPUT, Banff, ALTA, May 2003
53. Elforsk, Stockholm, Sweden, June 2003
54. Eurelectric, Brussels, Belgium, October 2003
55. CAMPUT, Halifax NS, May 2004
56. Edison Electric Institute, eforum, March 2005
57. EUCI, Seattle, May 2006 [Conference chair]
58. Ontario Energy Board, Toronto ON, June 2006
59. Edison Electric Institute, Madison WI, August 2006
60. EUCI, Arlington VA, September 2006 [Conference chair]
61. EUCI, Arlington VA September 2006
62. Law Seminars, Las Vegas, February 2007
63. Edison Electric Institute, Madison WI, August 2007
64. Edison Electric Institute, national eforum, 2007
65. EUCI, Seattle WA, 2007 [Conference chair]
66. Massachusetts Energy Distribution Companies, Waltham MA, July 2007.
67. Edison Electric Institute, Madison WI, July-August 2007.
68. Institute of Public Utilities, Lansing MI, 2007

69. EUCI, Denver, 2008 [Conference chair]
70. EUCI, Chicago, July 2008 [Conference chair]
71. EUCI, Toronto, March 2008 [Conference chair]
72. Edison Electric Institute, Madison WI, August 2008
73. EUCI, Cambridge MA, March 2009 [Conference chair]
74. Edison Electric Institute, national eforum, May 2009
75. Edison Electric Institute, Madison WI, July 2009
76. EUCI, Cambridge MA, March 2010 [Conference chair]
77. Edison Electric Institute, Madison WI, July 2010
78. EUCI, Toronto, November 2010 [Conference chair]
79. Edison Electric Institute, Madison WI, July 2011
80. EUCI, Philadelphia PA, November 2011 [Conference chair]
81. SURFA, Washington DC, April 2012
82. Edison Electric Institute, Madison WI, July 2012
83. EUCI, Chicago IL, November 2012 [Conference chair]
84. Law Seminars, Las Vegas NV, March 2013
85. Edison Electric Institute Washington DC, April 2013
86. Edison Electric Institute, Washington DC, May 2013
87. Edison Electric Institute, Madison WI, July 2013
88. National Regulatory Research Institute, Teleseminar, August 2013
89. EUCI, Chicago IL April 2014 [Conference chair]
90. Edison Electric Institute, Madison WI, July 2014
91. Financial Research Institute, Columbia MO, September 2014
92. Great Plains Institute, St. Paul MN, September 2014
93. Law Seminars, Las Vegas NV, March 2015
94. Edison Electric Institute, Madison WI, July 2015
95. Lawrence Berkeley National Laboratory, Vermont Future of Electric Utility Regulation Workshop
    January 2016
96. Great Plains Institute, Minneapolis MN, February 2016
97. Wisconsin Public Service Commission, Madison WI, March 2016
98. Society of Utility Regulatory Financial Analysts (SURFA), Indianapolis IN, April 2016
99. Edison Electric Institute, Madison WI, July 2016
100. Lawrence Berkeley National Laboratory, Webinar, November 2016
101. Washington State House of Representatives, Technology and Economic Development Committee, January 2017
102. National Regulatory Research Institute, Webinar, May 2017
103. National Conference of Regulatory Attorneys, Portland OR, May 2017
104. Edison Electric Institute, Madison WI, July 2017
105. Lawrence Berkeley National Laboratory, Webinar, August 2017
106. New England Conference of Public Utilities Commissioners, Hallowell ME, September 2017
107. Wisconsin Public Utilities Institute, Madison WI, October 2017
108. University of Wisconsin Department of Applied Economics, October 2017
109. NARUC, St Paul MN, forthcoming (January 2018).

Journal Referee

Agribusiness
American Journal of Agricultural Economics
Energy Journal
Journal of Economic Dynamics and Control
Materials and Society

Association Memberships (active)

International Association of Energy Economist

GLOSSARY OF TERMS

Attrition Relief Mechanism (ARM): An essential provision of multiyear rate plans that automatically adjusts allowed rates or revenues to address cost pressures without closely tracking the utility's own cost. Methods used to design ARMs include forecasts and indexation to quantifiable business conditions such as inflation and growth in the number of customers served.

Base Rates: The components of a utility's rates that address the costs of non-energy inputs such as labor, materials and capital.[1]

Capex: Capital expenditures

Cost Tracker: A mechanism providing expedited recovery of targeted costs. An account typically tracks costs that are eligible for recovery. These costs are then typically recovered via rate riders. Tracker treatment was traditionally limited to costs that are large, volatile and largely beyond the control of the utility. The scope of costs eligible for tracking has widened over time. In multiyear rate plans, trackers have been used for costs that are difficult for the ARM to address.

Earnings Sharing Mechanism (ESM): An ESM shares surplus or deficit earnings, or both, between utilities and customers, which result when the rate of return on equity deviates from its commission-approved target. ESMs often have dead bands in which earnings variances are not shared.

Efficiency Carryover Mechanism (ECM): A mechanism that allows for a share of lasting performance gains (or losses) to be kept by the utility for a set period of time when a multiyear rate plan expires.

Lost Revenue Adjustment Mechanism (LRAM): A ratemaking mechanism that compensates utilities for base rate revenue lost from specific causes such as demand-side management programs and distributed generation. Requires estimates of load impacts.

Marketing/Pricing Flexibility: Flexibility afforded to utilities to fashion rates and other terms of service in selected markets. Marketing flexibility is typically accomplished via light-handed regulation of rates and services with certain attributes. Services often eligible for flexibility include optional tariffs for standard services, optional value-added (discretionary) services, and services to competitive markets. Price floors are often established to discourage predation and cross-subsidization.

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[1] Base rates sometimes also include charges for costs of energy inputs like fuel and purchased power, but trackers usually adjust rates so these costs are recovered more exactly.

Multiyear Rate Plan (MYRP): A common approach to performance-based regulation that typically features a rate case moratorium for several years, an ARM, and performance incentive mechanisms for service quality.

Off-ramp Mechanism: An MYRP option that permits reconsideration of a multiyear rate plan under prespecified conditions such as an extremely high or low rate of return on equity.

Performance-Based Regulation (PBR): An approach to regulation designed to strengthen utility performance incentives.

Performance Incentive Mechanism (PIM): A popular form of performance-based regulation that links utility revenue or earnings to performance in targeted areas. Most PIMs involve metrics, targets (sometimes called *outcomes*) and financial incentives (rewards and penalties). Service quality and demand-side management are common focuses.

Rate Base: A utility's total "used and useful" plant in service, at original cost, minus accumulated depreciation and deferred income taxes.

Rate Rider: An explicit mechanism outlined on tariff sheets to allow a utility to receive supplemental revenue adjustments.

Revenue Decoupling Mechanism: A mechanism that periodically adjusts rates to ensure that actual revenue closely tracks allowed revenue. Decoupling can reduce the "throughput incentive" that can cause utilities to resist demand-side management.

RIIO: The British approach to PBR. The acronym stands for Revenues = Incentives + Innovation + Outputs. RIIO involves MYRPs that include relatively long rate case moratoria (e.g., eight years), a forecast-based ARM, and an extensive set of performance incentive mechanisms.

Statistical Benchmarking: The use of statistics on the operations of utilities to appraise utility performance. Methods commonly used in statistical cost benchmarking include unit cost and productivity indexes and econometric models.

Z Factor: A term in a rate or revenue cap index that permits rate adjustments for the financial impact of miscellaneous events (e.g., severe storms) that are beyond the utility's control.

THE SIMPLE ALGEBRA OF PBR

The net income of a business roughly equals its revenue (R) less its operating expenses and (net) interest charges (CKI). Revenue depends on the price (P_i) and quantity (Y_i) of each product i that is sold. Operating expenses include operation and maintenance expenses (COM), depreciation (CKD), and taxes (CKT). Hence,

$$\begin{aligned} \textit{Net Income} &= R - (COM + CKD + CKI + CKT) \\ &= \Sigma_i P_i Y_i - (COM + CKD + CKI + CKT). \end{aligned} \quad [1]$$

In a competitive market, prices reflect the cost of typical firms in the industry and not a supplier's own cost. Net income is thus boosted by good marketing and cost containment. A superior performance is not necessary to earn a competitive rate of return.

Consider now the net earnings of a utility operating under "cost-plus" regulation. Under this system, revenue equals the pro forma cost of service so that

$$R = C = COM + \mathrm{r} \cdot \frac{1}{2} \cdot VK + CKD + \mathrm{CKI} + CKT \quad [2]$$

where r is the target rate of return on equity and VK is the net plant value (aka rate base) so that $\mathrm{r} \cdot \frac{1}{2} \cdot VK$ is the pro forma return on equity.[1] Now

$$\begin{aligned} \textit{Net Income} &= \left(COM + \mathrm{r} \cdot \frac{1}{2} \cdot VK + CKD + CKI + CKT\right) \\ &\quad -(COM + CKD + CKI + CKT) \\ &= \mathrm{r} \cdot \frac{1}{2} \cdot VK. \end{aligned} \quad [3]$$

The only way for the utility to grow net income is to increase its rate base. There is no incentive to contain any cost in this stylized regulatory system.

Suppose, now, that we add a stylized performance incentive mechanism for cost to this system which automatically adjusts revenue for a share α of the difference between cost and a cost benchmark $(\bar{C})$.

$$R = C - \alpha \cdot (C - \bar{C}).$$

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[1] This assumes that the company's capital structure is comprised equally of debt and equity.

The PIM symmetrically lowers (raises) revenue to the extent that the proforma cost of service is greater (less) than the cost benchmark. Now

$$\textit{Net Income} = [\left(COM + r\cdot\tfrac{1}{2}\cdot VK + CKD + CKI + CKT\right)$$

$$-\alpha\cdot\left(COM + r\cdot\frac{1}{2}\cdot VK + CKD + CKI + CKT - \bar{C}\right)] - (COM + CKD + CKI + CKT)$$

$$= r\cdot\frac{1}{2}\cdot VK - \alpha\cdot(\bar{C} - COM + r\cdot\frac{1}{2}\cdot VK + CKD + CKI + CKT)$$

$$= (1-\alpha)\cdot r\cdot\tfrac{1}{2}\cdot VK - \alpha\cdot(\bar{C} - COM - CKD + CKI + CKT) \qquad [4]$$

The utility now has an incentive to contain the growth of rate base and other costs which is greater the higher is the value of α. If α=1, revenue equals the cost benchmark and

$$\textit{Net Income} = \bar{C} - (COM + CKD + CKI + CKT). \qquad [5]$$

Cost containment incentives are similar to those in competitive markets.

Consider now the net income of a utility operating under a stylized multiyear rate plan. We assume that revenue equals an external cost benchmark as adjusted by a mechanism that shares with customers a fraction (1- β) of the difference between the benchmark and the pro forma cost of service. Now

$$\textit{Net Income} = \left\{\bar{C} - (1-\beta)\cdot\left[\bar{C} - \left(COM + r\cdot\tfrac{1}{2}\cdot VK + CKD + CKI + CKT\right)\right]\right\}$$

$$-(COM + CKD + CKI + CKT)$$

$$= (1 - \beta)\cdot r\cdot\tfrac{1}{2}\cdot VK + \beta\cdot[\bar{C} - (COM + CKD + CKI + CKT)]. \qquad [6]$$

The utility has an incentive to contain growth in the rate base and other costs which is higher the higher is the value of β. If $\beta = 1$,

$$\textit{Net Income} = \bar{C} - (COM + CKD + CKI + CKT). \qquad [7]$$

The utility would once again have an incentive to contain cost that is similar to that in competitive markets.

This analysis shows that a cost PIM can strengthen a utility's cost containment incentives. However, the same effect can also be achieved by a multiyear rate plan. The design of a comprehensive cost PIM would involve many of the same challenges encountered in the choice of allowed revenue in an MYRP.

Category	Stat/Rule/ Tariff/Order	Definition
Statutes		
Customer Protections	216B.091	**RESIDENTIAL PROTECTIONS; DISCONNECTION** **216B.091 MONTHLY REPORTS.** (a) Each public utility must report the following data on residential customers to the commission monthly, in a format determined by the commission: (1) number of customers; (2) number and total amount of accounts past due; (3) average customer past due amount; (4) total revenue received from the low-income home energy assistance program and other sources contributing to the bills of low-income persons; (5) average monthly bill; (6) total sales revenue; (7) total write-offs due to uncollectible bills; (8) number of disconnection notices mailed; (9) number of accounts disconnected for nonpayment; (10) number of accounts reconnected to service; and (11) number of accounts that remain disconnected, grouped by the duration of disconnection, as follows: (i) 1-30 days; (ii) 31-60 days; and (iii) more than 60 days. (b) Monthly reports for October through April must also include the following data: (1) number of cold weather protection requests; (2) number of payment arrangement requests received and granted; (3) number of right to appeal notices mailed to customers; (4) number of reconnect request appeals withdrawn; (5) number of occupied heat-affected accounts disconnected for 24 hours or more for electric and natural gas service separately; (6) number of occupied non-heat-affected accounts disconnected for 24 hours or more for electric and gas service separately; (7) number of customers granted cold weather rule protection; (8) number of customers disconnected who did not request cold weather rule protection; and (9) number of customers disconnected who requested cold weather rule protection. (c) The data reported under paragraphs (a) and (b) is presumed to be accurate upon submission and must be made available through the commission's electronic filing system. A monthly report must be filed with the commission no later than 45 days after the last day of the month for which data is reported.
Customer Protections	216B.096	**216B.0976 NOTICE TO CITIES OF UTILITY DISCONNECTION.** Subdivision 1.**Notice required**. Notwithstanding section 13.685 or any other law or administrative rule to the contrary, a public utility, cooperative electric association, or municipal utility must provide notice to a statutory city or home rule charter city, as prescribed by this section, of disconnection of a customer's gas or electric service. Upon written request from a city, on October 15 and November 1 of each year, or the next business day if that date falls on a Saturday or Sunday, a report must be made available to the city of the address of properties currently disconnected and the date of the disconnection. Upon written request from a city, between October 15 and April 15, daily reports must be made available of the address and date of any newly disconnected properties. A city provided notice under this section must provide the information on disconnection to the police and fire departments of the city within three business days of receipt of the notice. For the purpose of this section, "disconnection" means a cessation of services initiated by the public utility, cooperative electric association, or municipal utility that affects the primary heat source of a residence and service is not reconnected within 24 hours. Subd. 2.**Data**. Data on customers that are provided to cities under subdivision 1 are private data on individuals or nonpublic data, as defined in section 13.02.
Rules		
Annual Reporting	7826.1300	**7826.1300 ANNUAL SERVICE QUALITY REPORT FILING.** On or before April 1 of each year, each utility shall file a report on its service quality performance during the last calendar year. These filings must be treated as "miscellaneous tariff filings" under the commission's rules of practice and procedure, part 7829.0100, subpart 11. This report must include at least the information set forth in parts 7826.1400 to 7826.2000.

Category	Stat/Rule/ Tariff/Order	Definition
Safety	7826.0400	**7826.0400 ANNUAL SAFETY REPORT.** On or before April 1 of each year, each utility shall file a report on its safety performance during the last calendar year. This report shall include at least the following information: A. summaries of all reports filed with the United States Occupational Safety and Health Administration and the Occupational Safety and Health Division of the Minnesota Department of Labor and Industry during the calendar year; and B. a description of all incidents during the calendar year in which an injury requiring medical attention or property damage resulting in compensation occurred as a result of downed wires or other electrical system failures and all remedial action taken as a result of any injuries or property damage described.
Reliability	7826.0500	**7826.0500 RELIABILITY REPORTING REQUIREMENTS.** Subpart 1. Annual reporting requirements. On or before April 1 of each year, each utility shall file a report on its reliability performance during the last calendar year. This report shall include at least the following information: A. the utility's SAIDI for the calendar year, by work center and for its assigned service area as a whole; B. the utility's SAIFI for the calendar year, by work center and for its assigned service area as a whole; C. the utility's CAIDI for the calendar year, by work center and for its assigned service area as a whole; D. an explanation of how the utility normalizes its reliability data to account for major storms;
		E. an action plan for remedying any failure to comply with the reliability standards set forth in part 7826.0600 or an explanation as to why noncompliance was unavoidable under the circumstances;
		F. to the extent feasible, a report on each interruption of a bulk power supply facility during the calendar year, including the reasons for interruption, duration of interruption, and any remedial steps that have been taken or will be taken to prevent future interruption;
		G. a copy of each report filed under part 7826.0700;
		H. to the extent technically feasible, circuit interruption data, including identifying the worst performing circuit in each work center, stating the criteria the utility used to identify the worst performing circuit, stating the circuit's SAIDI, SAIFI, and CAIDI, explaining the reasons that the circuit's performance is in last place, and describing any operational changes the utility has made, is considering, or intends to make to improve its performance;
		I. data on all known instances in which nominal electric service voltages on the utility's side of the meter did not meet the standards of the American National Standards Institute for nominal system voltages greater or less than voltage range B;
		J. data on staffing levels at each work center, including the number of full-time equivalent positions held by field employees responsible for responding to trouble and for the operation and maintenance of distribution lines;
		K. any other information the utility considers relevant in evaluating its reliability performance over the calendar year.
Reliability	7826.0600	**7826.0600 RELIABILITY STANDARDS.** Subpart 1. **Annually proposed individual reliability standards.** On or before April 1 of each year, each utility shall file proposed reliability performance standards in the form of proposed numerical values for the SAIDI, SAIFI, and CAIDI for each of its work centers. These filings shall be treated as "miscellaneous tariff filings" under the commission's rules of practice and procedure, part 7829.0100, subpart 11. Subp. 2. **Annually set, utility-specific, reliability standards.** The commission shall set reliability performance standards annually for each utility in the form of numerical values for the SAIDI, SAIFI, and CAIDI for each of its work centers. These standards remain in effect until the commission takes final action on a filing proposing new standards or changes them in another proceeding.
Reliability	7826.0700	**7826.0700 REPORTING MAJOR SERVICE INTERRUPTIONS.** Subpart 1. **Contemporaneous reporting.** A utility shall promptly inform the commission's Consumer Affairs Office of any major service interruption. At that time, the utility shall provide the following information, to the extent known: A. the location and cause of the interruption; B. the number of customers affected; C. the expected duration of the interruption; and D. the utility's best estimate of when service will be restored, by geographical area.
		Subp. 2. **Written report.** Within 30 days, a utility shall file a written report on any major service interruption in which ten percent or more of its Minnesota customers were out of service for 24 hours or more. This report must include at least a description of: A. the steps the utility took to restore service; and B. any operational changes the utility has made, is considering, or intends to make, to prevent similar interruptions in the future or to restore service more quickly in the future.
Billing Accuracy	7826.1400	**7826.1400 REPORTING METER-READING PERFORMANCE.** The annual service quality report must include a detailed report on the utility's meter-reading performance, including, for each customer class and for each calendar month: A. the number and percentage of customer meters read by utility personnel; B. the number and percentage of customer meters self-read by customers; C. the number and percentage of customer meters that have not been read by utility personnel for periods of six to 12 months and for periods of longer than 12 months, and an explanation as to why they have not been read; and D. data on monthly meter-reading staffing levels, by work center or geographical area.

Category	Stat/Rule/ Tariff/Order	Definition
Customer Protections	7826.1500	**7826.1500 REPORTING INVOLUNTARY DISCONNECTIONS.** The annual service quality report must include a detailed report on involuntary disconnections of service, including, for each customer class and each calendar month: A. the number of customers who received disconnection notices; B. the number of customers who sought cold weather rule protection under Minnesota Statutes, sections 216B.096 and 216B.097, and the number who were granted cold weather rule protection; C. the total number of customers whose service was disconnected involuntarily and the number of these customers restored to service within 24 hours; and D. the number of disconnected customers restored to service by entering into a payment plan.
Responsiveness	7826.1600	**7826.1600 REPORTING SERVICE EXTENSION REQUEST RESPONSE TIMES.** The annual service quality report must include a report on service extension request response times, including, for each customer class and each calendar month: A. the number of customers requesting service to a location not previously served by the utility and the intervals between the date service was installed and the later of the in-service date requested by the customer or the date the premises were ready for service; and B. the number of customers requesting service to a location previously served by the utility, but not served at the time of the request, and the intervals between the date service was installed and the later of the in-service date requested by the customer or the date the premises were ready for service.
Responsiveness	7826.1700	**7826.1700 REPORTING CALL CENTER RESPONSE TIMES.** The annual service quality report must include a detailed report on call center response times, including calls to the business office and calls regarding service interruptions. The report must include a month-by-month breakdown of this information. *See also* ***7826.1200 CALL CENTER RESPONSE TIME and QSP Tariff, Subsection E2 Sheet 7.7.***
Customer Protections	7826.1800	**7826.1800 REPORTING EMERGENCY MEDICAL ACCOUNT STATUS.** The annual service quality report must include the number of customers who requested emergency medical account status under Minnesota Statutes, section 216B.098, subdivision 5, the number whose applications were granted, and the number whose applications were denied and the reasons for each denial.
Customer Protections	7826.1900	**7826.1900 REPORTING CUSTOMER DEPOSITS.** The annual service quality report must include the number of customers who were required to make a deposit as a condition of receiving service.
Customer Protections	7826.2000	**7826.2000 REPORTING CUSTOMER COMPLAINTS.** The annual service quality report must include a detailed report on complaints by customer class and calendar month, including at least the following information: A. the number of complaints received; B. the number and percentage of complaints alleging billing errors, inaccurate metering, wrongful disconnection, high bills, inadequate service, and the number involving service-extension intervals, service-restoration intervals, and any other identifiable subject matter involved in five percent or more of customer complaints; C. the number and percentage of complaints resolved upon initial inquiry, within ten days, and longer than ten days; D. the number and percentage of all complaints resolved by taking any of the following actions: (1) taking the action the customer requested; (2) taking an action the customer and the utility agree is an acceptable compromise; (3) providing the customer with information that demonstrates that the situation complained of is not reasonably within the control of the utility; or (4) refusing to take the action the customer requested; and E. the number of complaints forwarded to the utility by the commission's Consumer Affairs Office for further investigation and action.
Tariffs		

Category	Stat/Rule/ Tariff/Order	Definition
Annual Reporting	Gen'l Rules & Regs, Sec 1.9, Sheets 7.2 through 7.11 Subs. D, Sheet 7.6	**SERVICE QUALITY (QSP)** D. Reporting Requirements By May 1 of each year, the Company will file a report with the Minnesota Public Utilities Commission detailing the Company's actual performance as compared with the thresholds established for each metric. This report will be accompanied by supporting data. All metrics shall be reported statewide, with the following additional reporting provided: • SAIDI and SAIFI shall be presented by Work Center. • Customer Complaints shall be presented by complaint category. • The report shall specify the number of customers qualifying for Customer Outage Credits and the associated bill credit calculations. • Natural Gas Emergency Response shall include the averages for Answer and Talk Time, Dispatch Time, Travel Time, and total response time by each call type and in total for all call types. If the Company adjusts any of its internal guidelines for dispatching and responding to natural gas emergency calls, those changes shall be noted. • The report shall include data on municipal pumping outages. The Company shall work with the Department and Commission staff to ensure that the information included will assist the Commission's decision making.
Customer Protections	Gen'l Rules & Regs, Sec 1.9, Sheets 7.2 through 7.11. Subs. E1, Sheet 7.7	**SERVICE QUALITY (QSP)** This metric measures the number of Customer Complaints submitted by the Commission's Consumer Affairs Office. An under performance payment will be assessed in any year in which the number of complaints exceeds 0.2059 complaints per 1,000 customers. Customer complaints will be recorded and reported with no exclusions. The Company may request exclusion of Customer Complaints that the Company can demonstrate are the result of an event beyond the Company's control, which the Company took reasonable steps to address. Customer Complaints will be reported in the following categories: • Billing & Credit • Customer Service • Meter Reading • Trouble Orders • Reliability Duration • Reliability Frequency • Other
Responsiveness	Gen'l Rules & Regs, Sec 1.9, Sheets 7.2 through 7.11. Subs. E2, Sheet 7.7	**SERVICE QUALITY (QSP)** This metric measures the Company's time to answer customer calls directed to the Company's call center or to its business office. The benchmark is 80 percent of the calls are answered within 20 seconds. The under performance payment will be assessed in any performance year in which less than 80 percent of calls are answered within 20 seconds. Telephone Response Time will be recorded and reported with no exclusions. The Company may request exclusion of certain calls that the Company can demonstrate are the result of an event beyond the Company's control, which the Company took reasonable steps to address.
Reliability	Gen'l Rules & Regs, Sec 1.9, Sheets 7.2 through 7.11. Subs. E3, Sheet 7.8	**SERVICE QUALITY (QSP)** This metric measures the duration of Interruptions Customers experience during the performance year. The under performance payment will be assessed in any performance year in which the Company's annual statewide SAIDI exceeds 133.23 minutes. Xcel Energy shall pay for periodic audits of the accuracy of the outage duration data by an independent firm overseen by the Minnesota Department of Commerce and the Minnesota Office of the Attorney General and Commission Staff. The firm will have expertise in reliability reporting and electric industry practices and will evaluate the Company's outage records in light of reasonable and prudent utility practices. The verification of the Company's records by an independent firm shall identify whether the sufficiency of the documentation and/or errors in the documentation resulted in a problem that materially compromised the integrity of the annually reported value for outage duration. The results of these audits will inform the decision regarding the application of any under performance payments required under this tariff. The SAIDI under performance payment shall be triggered for a given reporting year in the event that the underlying outage records used by the Company to determine the annually reported SAIDI value are found to be insufficient or inaccurate on completion of the audit process. The determination of a required payment under this provision will be made, after notice and hearing, by the Commission. SAIDI will be reported as defined in this tariff. However, the Company may request exclusion of customer outage events that occur as a result of illegal work stoppages, civil unrest, criminal acts, actions or orders of any government branch or governing body that restricts vehicle movement or deployment of resources (road closures, etc.), natural disaster (flood, earthquake, etc.), or loss of service from a foreign utility.

Category	Stat/Rule/ Tariff/Order	Definition
Reliability	Gen'l Rules & Regs, Sec 1.9, Sheets 7.2 through 7.11. Subs. E4, Sheet 7.9	**SERVICE QUALITY (QSP)** This metric measures the frequency of Interruptions that Customers experience during the performance year. The under performance payment will be assessed in any performance year in which the Company's statewide SAIFI exceeds 1.21 outage events. SAIFI will be reported as defined in this tariff. However, the Company may request exclusion of customer outage events that occur during periods of, or as a result of illegal work stoppages, civil unrest, criminal acts, actions or orders of any government branch or governing body that restricts vehicle movement or deployment of resources (road closures, etc.), natural disaster (flood, earthquake, etc.), or loss of service from a foreign utility.
Responsiveness	Gen'l Rules & Regs, Sec 1.9, Sheets 7.2 through 7.11. Subs. E5, Sheet 7.9	**SERVICE QUALITY (QSP)** This metric measures the Company's average annual response time to natural gas emergency calls. The under performance payment will be assessed in any year in which the Company's annual average natural gas emergency response time exceeds 60 minutes. Natural Gas Emergency Response will be recorded and reported with no exclusions. The Company may request exclusion of certain events if the Company can demonstrate circumstances that are beyond the Company's control, which the Company took reasonable steps to address.
Reliability	Gen'l Rules & Regs, Sec 1.9, Sheets 7.2 through 7.11. Subs E6, Sheet 7.10	**SERVICE QUALITY (QSP)** This service quality provision is intended to compensate individual customers whose premises incur outages unrelated to MEDs that occur at the premises they occupy, and that exceed the following performance year standards: Only customers who have continuously resided at the address experiencing the Interruptions for the consecutive years are eligible to receive the customer credits. <u>Single Year Outages</u> $50 annual credit to individual customers experiencing at least 6 interruptions. $50 credit to individual customers per Interruption lasting 24 hours or more. $200 credit to Municipal Pumping Service customers (Rate Code A41) for any outage unrelated to MEDs that exceed 1 min. in duration. $100 credit to Small Municipal Pumping Service customers (Rate Code A40) for any outage unrelated to MEDs that exceed 1 min. in duration. <u>Consecutive Year Outages</u> (does not apply to Municipal Pumping customers) $75 to a custom after the 2nd year if the customer experiences 5 or more Interruptions in 2 consecutive years. $100 to a customer after the 3rd year if the cusotmer experiences 4 or more Interruptions for 3 consecutive years. $125 to a customer after the 4th year, and after each consecutive year thereafter, if the customer experiences 4 or more Interruptions for 4 or more consecutive years.
Billing Accuracy	Gen'l Rules & Regs, Sec 1.9, Sheets 7.2 through 7.11. Subs. E7, Sheet 7.11	**SERVICE QUALITY (QSP)** This metric measures the level of accurate invoices issued to customers during the performance year. The under performance payment will be assessed in any performance year in which the annual accuracy rate is less than 99.3%.
Billing Accuracy	Gen'l Rules & Regs, Sec 1.9, Sheets 7.2 through 7.11. Subs. E8, Sheet 7.11	**SERVICE QUALITY (QSP)** This metric measures the Company's average number of cancelled billing periods on a rebilled invoice. The under performance payment will be assessed in any performance year in which the average annual number of cancelled billing periods exceeds 2.35. Invoice Accuracy and Invoice Adjustment Timeliness will be recorded and reported with no exclusions. The Company may request exclusion of certain events affecting the accuracy rate or canceled billing periods if the Company can demonstrate circumstances that are beyond the Company's control, which the Company took reasonable steps to address.
Annual Reporting	Gen'l Rules & Regs, Sec 3.15, Sheets 17.2 through 17.4 Subs. E, Sheet 17.4	**METER EQUIPMENT MALFUNCTIONS** E. REPORTING The Company will file an annual Meter Equipment Malfunction Investigation and Remediation Report with the Minnesota Public Utilities Commission. The report will be filed as part of the Company's Annual Electric and Natural Gas Service Quality Reports due April 1 and May 1 of each year, respectively.

Category	Stat/Rule/ Tariff/Order	Definition
Responsiveness	Gen'l Rules & Regs, Sec 3.15, Sheets 17.2 through 17.4 Subs. B, Sheet 17.2	**METER EQUIPMENT MALFUNCTIONS** B. The Company will track and report its average annual performance time for both Electric and Natural Gas Meter Equipment Malfunction Invesitgations and Remediation. 1. Natural Gas Meters The Company will report and compare its average annual performance for NG Meter Equipment Investigations and Meter Equipment Remediation against the following average annual response targets: Investigate & Remediate: 9 calendar days from the point of the potential meter equipment issue is identified and order is issued. Investigate and Refer: 9 calendar days from the point of the potential meter equipment issue is identified and order is issued. Remediate upon Referral: 15 calendar days from the point a meter equipment issue is confirmed via field investigation and a referral order is issued. 2. Electric Meters Investigate & Remediate: 9 calendar days from the point of the potential meter equipment issue is identified and order is issued. Investigate and Refer: 9 calendar days from the point of the potential meter equipment issue is identified and order is issued. Remediate upon Referral: 1 calendar day from the point a meter equipment issue is confirmed via field investigation and a referral order is issued.
Billing Accuracy	Gen'l Rules & Regs, Sec 3.15, Sheets 17.2 through 17.4 Subs. C, Sheet 17.3	**METER EQUIPMENT MALFUNCTIONS** If the Company does not repair or replace natural gas or electric meter equipment found to be malfunctioning within 10 calendar days (20 cal days for natural gas Remediate upon Referral malfunctions), the Company will not rebill the customer for any under-billing amount owed for service occurring between the date the potential issue was identified and the date the Company remedied the meter equipment malfunction. However, the Company may rebill for the amount owed for service occurring between the date the potential issue was identified an the date the Company remedied the meter equipment malfunction if the Company's actions were delayed as a result of any Exclusions identified in Sec D. Subject to the requirements of the Meter Equipment tariff, the Company will apply its Billing Adjustments tariff language in Sec No. 6 of the Company's General Rules and Regulations to any rebilling resulting from malfunctioning meter equipment.
Orders		
Reliability	Order: Docket 07-422	2. Augment its next filing to include a description of the policies, procedures and actions it has implemented, and plans to implement, to assure reliablity and include information on how it is demonstrating proactive management of the system as a whole, increased reliablity and active contingency planning 3. Include a summary table (or summary information in some format) that allows the reader to more easily assess the overall reliability of the system and identify the main factors that affect reliablity
Reliability	Order: Docket 10-310	8. For reports due April 1, 2011, the Commission requires that Xcel make preparation to begin reporting on MAIFI and also begin to discuss other relevant power quality issues.
Reliability	Order: Docket 12-961	1. A table with annual MAIFI results for Minnesota and our four work centers using three different normalization methodologies; 2. A table with the MAIFI results and Customer Interruptions by month and by work center; 3. A five-year historical look for Minnesota MAIFI that shows the three different normalization methodologies and their associated trend lines; 4. A pareto chart showing the top causes for interruptions for the current year; and 5. A pareto chart showing the top causes for interruptions for the past five years.
Reliability	Order: Docket 08-393	5. Xcel shall report on the major causes of outages for major event days
Responsiveness	Order: Docket 08-871	• Volume of Investigate and Remediate Field orders; • Volume of Investigate and Refer Field orders; • Volume of Remediate Upon Referral Field orders; • Average response time for each of the above categories by month and year; • Minimum days, maximum days, and standard deviations for each category; and • Volume of excluded field orders.
Responsiveness	Nov 2, 2017 Order: Docket 17-553	1. Include in its SQ reports for 2018 and 2019, discussion of the successes and challenges arising from the change in general customer service call center hours. If there is a drop in service quality after the change is implemented, the Company should explain in detail how it will improve.

CERTIFICATE OF SERVICE

I, Lynnette Sweet, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E002/CI-17-401

Dated this 21st day of December 2017

/s/

____

Lynnette Sweet
Regulatory Administrator

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