Direct Testimony and Schedules
Greg P. Chamberlain

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-21-630
Exhibit___(GPC-1)

Policy

October 25, 2021

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION AND JOB RESPONSIBILITIES.

A. My name is Greg P. Chamberlain. I am the Regional Vice President for Regulatory and Government Affairs for Northern States Power Company-Minnesota (NSPM or the Company), d/b/a Xcel Energy. In this role, I am responsible for state government relations and regulatory filings with the utility commissions in Minnesota, North Dakota, and South Dakota, including proceedings related to rates, resource planning, and service quality filings.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I joined Xcel Energy in 2000 and have held positions in the Company including in the Transmission and Energy Supply business areas prior to serving as Regional Vice President for Government and Community Relations, and then moving to my current role. While serving as Director of Transmission Portfolio Delivery for the Company, I was responsible for the engineering, project management, project controls and permitting of a $4 billion electric transmission capital portfolio across 10 states. In addition, I acted as Xcel Energy's management committee representative on each of four CapX2020 projects. As General Manager of Power Generation, I was responsible for the operations of the Company's fleet of power plants across Minnesota, Wisconsin, and South Dakota. I have a Master of Business Administration from the University of Minnesota Carlson School of Management and a Bachelor of Science degree in Chemical Engineering from Purdue University. Exhibit___(GPC-1), Schedule 1 summarizes my qualifications.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I present the Company's overall case to the Minnesota Public Utilities Commission for approval of a multi-year rate plan (MYRP) for the period 2022-2024. A multi-year rate plan, modeled after and incorporating the lessons learned from our previous MYRP, approved in Docket No. E002/GR-15-862, (the 2016-2019 MYRP) and extended for two additional years by the 2020 stay-out in Docket No. E002/M-19-688 and the 2021 stay-out in Docket No. E002/M-20-743, can provide many benefits for our customers, policy makers, regulators, other stakeholders, and the Company.

To support our request and inform the Commission's decision in this matter, my testimony will:

- Discuss the successes achieved through the 2016-2019 MYRP and the 2020 and 2021 stay-outs and why another MYRP provides the proper ratemaking construct now.
- Explain how this MYRP proposal will help us provide a better product for our customers while still maintaining affordability, and continue to collaborate with stakeholders, as the utility landscape continues to evolve.
- Outline the Company's three-year multi-year rate proposal.
- Demonstrate how the Company's proposed MYRP (1) complies with Minnesota Statute § 216B.16, subd. 19 (the MYRP Statute) and the Commission's MYRP Order; and, (2) results in just and reasonable rates.
- Describe the structure of our case and introduce the Company's witnesses.

Overall, my testimony describes the Company's plans to both (1) build on the successes that we and our stakeholders have achieved over the past six years; and (2) support these efforts going forward. Understanding our rate request from this perspective confirms that our proposed MYRP is consistent with the public interest and continues to be the appropriate ratemaking construct for the Company.

Q. CAN YOU SUMMARIZE THE COMPANY'S RATE REQUEST?

A. We propose a three-year rate plan, with a 2022 test year net incremental base revenue deficiency of $396.0 million; a 2023 plan year net incremental revenue deficiency of $150.2 million; and a 2024 plan year net incremental revenue deficiency of $131.2 million. These revenue deficiencies are based on a 10.20 percent return on equity (ROE) throughout the three-year MYRP period, as recommended by Company witness Mr. Dylan W. D'Ascendis and are reflected in Table 1, below.

Table 1
Revenue Deficiencies During Term of MYRP
($ in millions, rounded)

	2022	2023	2024	Total
Net Incremental Deficiency	**$396**	**$150**	**$131**	**$677**
Net percent rate increase	**12.2%**	**4.8%**	**4.2%**	**21.2%**

We also propose rolling the revenue requirements from certain projects that are currently recovered through riders into base rates. While these rider roll-ins do not impact the total bills paid by our customers (since the roll-in will lead to a decrease in the revenues recovered through the riders), they increase the base rate increase request for 2022 by $150 million, while decreasing the base rate increase request by $14 million and $13 million in 2023 and 2024, respectively, compared to the numbers presented in Table 1.

Q. DID THE COMPANY CONSIDER ALTERNATIVES TO FILING THIS CASE OR OTHER OPTIONS TO THE COMPANY'S RATE REQUEST?

A. Yes. We considered whether another "stay out" could be proposed by further extending the sales or other true-ups. However, we see tremendous value in another MYRP, to break the cycle of annual filings and stay-out proceedings.

At the same time, we recognize that the COVID-19 pandemic disrupted the economy and our communities and continues to impact our residential and business customers. Therefore, we explored options to mitigate the impact of 2022 interim rates on our customers, and we present an alternative to standard interim rates later in my testimony. If our alternative package of 2022 and 2023 interim rates is approved, we would collect 2022 interim rates at a level that is materially smaller than what we would otherwise collect under the statutory interim rate formula.

Q. WHY IS THE COMPANY PROPOSING ANOTHER MULTI-YEAR RATE PLAN?

A. The last six years have proven the value of an MYRP to a broad group of stakeholders. As I discuss in more detail below, in our last rate case, we set out a number of goals that could be achieved and benefits that could be derived from a MYRP ratemaking construct. The past six years have demonstrated that the parties and Commission succeeded in crafting a MYRP that delivered on this potential. We believe another MYRP can deliver similar benefits going forward.

As we discussed in that case, customer demands, state policy initiatives, and the business environment for utilities are changing. These ongoing changes require utilities and regulators to change as well. We need to innovate to better respond to the changing needs of customers and other constituencies. Our current MYRP proposal will create the time and space to enable us to do so, while providing electric service at just and reasonable rates over this time period. As I discuss below, the Company continues pursuing a number of critical initiatives, in concert with our stakeholders, including: (1) expanding our renewable energy portfolio and further transforming our generation fleet; (2) creating an advanced distribution grid to better serve our customers and enable further transformation of our overall energy delivery system; and (3) assisting in continued beneficial electrification and the electrification of Minnesota's transportation system. Another MYRP will enable this critical work to continue, for the benefit of our customers and the State.

Q. WHAT WERE THE POLICY CONSIDERATIONS THAT LED THE COMPANY TO PROPOSE A MYRP IN ITS LAST RATE CASE?

A. A number of factors led us to propose a MYRP, including:

- changing customer and stakeholder needs and expectations.
- emerging technologies.
- stagnant or declining sales.
- the need to break the cycle of increasingly frequent rate case filings.
- the opportunities created by a MYRP – for the Company, for customers and others.

These same factors continue to support a MYRP today.

Q. AND DID THE 2016-2019 MYRP SUCCEED IN ADDRESSING THOSE ISSUES IN A MEANINGFUL WAY?

A. Absolutely, and the results of the 2016-2019 and the subsequent 2020 and 2021 stay-outs are reflected in this filing. Looking back at the past six years, the MYRP provided multiple benefits to stakeholders, such as:

- Enabling unprecedented stakeholder engagement that has informed the Company's 2019 Integrated Resource Plan (IRP), the Commission's ongoing Performance Based Ratemaking (PBR) docket, the Company's advanced grid efforts and plans, as set forth in the Integrated Distribution Plan (IDP), and the Company's ambitious "Relief and Recovery" plan to aid Minnesota's recovery from the ongoing COVID-19 pandemic.
- Advancement of major new policy initiatives, as I discuss below.
- Preserving regulatory oversight through multiple compliance filings and the implementation of true-ups to reflect actual results regarding sales and provide consumer protections regarding capital investments and property taxes.
- Breaking the cycle of constant rate cases by setting rates for the four-year MYRP term and by providing a platform for a stay-out in 2020 and 2021 through the continuation of the true-up mechanisms used in the MYRP; meaning a break from rate case proceedings for the Company, regulators and our customers and other stakeholders – time that was used to advance the major policy initiatives.

Q. WHAT ARE SOME OF THOSE KEY POLICY INITIATIVES UNDERTAKEN DURING THESE PAST SIX YEARS?

A. First and foremost, in December 2018, the Company announced an industry-leading vision for providing carbon-free energy to our customers by 2050. We were the first major utility in the nation to adopt such a vision, and many utilities and policymakers across the country have since followed our lead and made the same commitment. Xcel Energy also announced its vision to work with other stakeholders and industry groups to power more than 1.5 million electric vehicles (EVs) in the states it serves by 2030, transforming the future of clean, affordable transportation.

In addition, this time period has seen a number of other substantial and important policy-driven efforts, including:

- Development and subsequent refinement of the Integrated Resource Plan, informed by nearly 20 public workshops and meetings and independent expert analysis. The IRP sets forth a plan that calls for substantial new renewable, energy efficiency and demand response resources, as well as the retirement of the last of the Company's coal-fired plants by 2030.
- Stakeholder engagement that informed the Company's advanced grid initiative and our Integrated Distribution Plans which set out our plans for modernizing our distribution grid to meet the new expectations and demands of our customers and other stakeholders.
- Substantial and ongoing work by the Commission and stakeholders on performance-based ratemaking, including the development of equity and service quality metrics.
- Launch of our Residential Time of Use (TOU) Pilot, *Flex Pricing*, which explores the ability to reduce peak demand through price signals and further enable customers to save by shifting to off-peak energy use through awareness-building, education, and data sharing.

- Development of our expanded and fully subscribed Renewable*Connect offering in response to customers' desire for both increased choice and more renewable energy.
- Substantial community development work, particularly in our host communities of Sherburne County and the City of Becker.
- Work with Southern Minnesota Municipal Power Agency (SMMPA) on a compromise related to the early retirement of the Sherco 3 generating facility, and economic dispatch of the unit until its retirement.
- Regulatory approval, and in most cases, implementation of several EV pilots and programs, for our customers, including: (1) Residential EV Service through the successful Accelerate at Home program where customers charge vehicles using off-peak rates; (2) Fleet EV Service Pilot, which defrays the cost of deploying fleet EV chargers; (3) Public Charging Pilot, which encourages the development of public charging facilities by providing "make ready" infrastructure; (4) Residential EV Subscription Service pilot, our fully subscribed pilot program which provides flat monthly subscription pricing for off-peak EV charging; and (5) Multi-Dwelling Unit EV Service pilot to provide infrastructure for EV charging at apartment buildings.
- Development of a new TOU rate design for general service customers, including commercial EV charging, which the Company will test alongside a parallel rate design pilot, the result of a compromise with stakeholders.
- Regulatory approval of the Company's request to offer the Sherco 2 and King coal-fired generation plants to the Midcontinent Independent System Operator (MISO) market seasonally, allowing the Company to

idle the plants for six months of the year, resulting in customer cost savings and reduced carbon emissions.

- Development of the "Relief and Recovery" proposals brought forward at the Commission's request exploring ways Minnesota's utilities can assist in the State's economic recovery from the COVID-19 pandemic. This effort included our proposal to build the largest solar project in the state's history- effectively replacing a coal unit at our Sherco site with solar, as well as a robust plan to accelerate adoption of electric vehicles through purchase rebates for light duty vehicles and buses.
- Facilitating the in-servicing of over 1,800 MW of new wind facilities—both Company-owned and through purchased power agreements (PPAs)—and repowering over 250 MW of existing wind projects from 2019 through 2021.
- Regulatory approval for the repowering of an additional six wind projects (over 750 MW) in response to the Commission's Relief and Recovery docket goals.
- Proposal of a three-year Workforce Development Pilot focused on developing skills for those in traditionally under-represented communities to succeed in energy-related construction careers, with potential for graduates to work on the Sherco Solar Project noted above, as well as other Company construction activities.
- Implementation of a Payment Plan Credit program which provides relief to residential electric customers at risk of permanently falling behind in their payments during the COVID-19 pandemic.
- Successful implementation of the Business Incentive and Sustainability (BIS) Rider with twelve different Minnesota businesses.

- Implementation of a temporary COVID-19 relief program through the BIS Rider tariff for customers up to 2,000 kW with business losses attributable to the pandemic.
- Successful implementation of relief program aimed at small businesses affected by either the COVID-19 pandemic or the civil unrest experienced in our communities in 2020.

These successes all align with state policy goals and provide substantial benefits to our communities and our customers. In fact, our leadership in areas such as decarbonizing our energy supply has been nationally recognized. As President Biden recently noted, Xcel Energy "led the way" as the first major utility in the country to set a goal of providing carbon free energy by 2050, with 20 other utilities having now set a similar goal.

We believe our actions and successes over the past six years – and our plans going forward – not only demonstrate the value of a MYRP ratemaking construct, but merit consideration as the Commission determines the Company's appropriate ROE for the Company in this proceeding. A fair and reasonable ROE will signal to the Company that our work is recognized and valued. Conversely, a low ROE will send the opposite message.

The success of the 2016-2019 MYRP shaped the Company's preparation of this filing and led us to propose this MYRP, modeled after the 2016-2019 MYRP, with a few adjustments I will discuss below.

II. THE COMPANY AND OUR VISION FOR THE FUTURE

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

A. In this section of my testimony, I first provide background information about the Company before describing the Company's vision for the future. I then discuss how that vision and our plans to achieve it are reflected in this rate case filing. Finally, I discuss some of the challenges we face in achieving this vision and how those challenges also impact this filing.

Q. PLEASE FIRST DESCRIBE NSPM.

A. NSPM serves more than 1.5 million electricity customers in Minnesota, North Dakota, and South Dakota. NSPM is part of an integrated system of diverse generation resources and transmission that serves the upper Midwest, including Xcel Energy's operations in Wisconsin and Michigan served by NSP-Wisconsin (collectively, the NSP System). Our operations include power plants with a net maximum capacity of almost 9,700 MW, more than 8,400 miles of transmission lines, and approximately 548 transmission and distribution substations.

The NSP System includes approximately 4,300 megawatts (MW) of renewable energy, including wind, hydro, biomass, and solar resources. As Company witness Mr. Randy Capra discusses, over the course of this MYRP, we will add more wind projects to our system, as outlined in our pending 2020-2034 Upper Midwest Resource Plan, which includes plans to add approximately 6,000 MW of renewable energy and battery energy storage over the next 15 years.

Xcel Energy supports our communities and Minnesota's economy through local spending, taxes, and community involvement. Last year, we spent more than $925 million with Minnesota suppliers, including $38 million with diverse suppliers. As the largest property taxpayer in the state, we paid almost $200 million in property taxes last year. As one of the state's largest employers, we provide good family-supporting jobs for more than 4,500 Minnesotans.

In addition, the Company remains committed to the communities in which we operate – a commitment shared by our employees. In 2020, our dedicated employees found creative, safe ways to volunteer and give back to our communities, volunteering more than 22,000 hours to support 290 nonprofits and donating close to $1.4 million throughout the year. A significant part of the Company's commitment to our communities involves building an environment of inclusion, diversity, and equity in our company and community, and we have devoted significant resources to that effort, as discussed by Company witness Ms. Ruth K. Lowenthal. This year, we added a diversity, equity and inclusion (DEI) metric as a key performance indicator on our corporate scorecard, and it will be one of the factors that determine our company's incentive pay for employees and leaders. We supported the Energy Conservation and Optimization (ECO) Act, which was signed into law in May 2021. Under this act, Xcel Energy will be spending at least $7.6 million per year (beginning in 2022) on energy efficiency programs dedicated to helping low-income customers in the state.

Q. AND WHO DO YOU CONSIDER THE COMPANY'S STAKEHOLDERS, AS YOU USE THAT TERM IN THIS TESTIMONY?

A. I use this term broadly. Our stakeholders include a diverse group of interests, including our customers, employees, and the communities in which we serve. Our stakeholders also include local, state and federal regulators and policy makers, as well as labor, environmental and customer advocacy organizations, among others.

Q. PLEASE DESCRIBE THE COMPANY'S OVERARCHING GOALS AS YOU LOOK TO THE FUTURE.

A. Our vision is to be the preferred and trusted provider of the energy our customers need. That means delivering not just safe, affordable, reliable and increasingly carbon-free electric service on an equitable basis to all our customers, but a better overall product and experience for our customers. To achieve that, the Company focuses on three strategic priorities:

(1) to lead the clean energy transition
(2) to enhance our customers' experience
(3) to continue providing affordable, equitable and highly reliable electric service in the face of new challenges posed by increasing weather volatility, cybersecurity threats, electrification, and expanding demands on the distribution system among other things.

My testimony will discuss how these three strategic priorities will shape our work over the course of the next several years and how that work is reflected in this MYRP request. Of course, as we focus on these priorities, we will continue to work to maintain and improve our record of excellent safety and reliability, provide a safe work environment that sends each and every employee home injury-free, and support our workforce and the communities in which we operate.

Q. AND WHAT ARE SOME OF THE KEYS TO THE COMPANY ACHIEVING ITS VISION?

A. To realize our vision, we must constantly challenge ourselves to provide safe, clean, reliable, and affordable energy in a manner that delivers a better product to our customers, while also supporting constructive relationships with our regulators and other policy makers and stakeholders.

Some of the work necessary to achieve our vision is internal to the Company – the work of our nuclear operations team, for example, to continue its track record of improving performance and decreasing costs, as discussed by Company witness Mr. Peter Gardner. Across the Company, our teams work with our core priorities in mind and challenge themselves to improve performance while controlling costs. That work, and the investments and expenses necessary to support it, is critical to our ability to deliver increasingly low-carbon energy, at affordable rates, and on a consistent and reliable basis. The MYRP we propose here allows that work to continue.

We also recognize that we cannot reach our goals, and the State's goals, alone. Therefore, broad stakeholder engagement will continue to play a critical role in our work, and our proposed MYRP frees resources, for us and other stakeholders, that would otherwise be devoted to rate case filings.

Finally, the work ahead – work the State and our key stakeholders want us to pursue – depends on a supportive regulatory environment. This work requires resources, and the Company will be competing for the necessary capital with others inside and outside of Xcel Energy. To attract that capital, the sound financial footing provided by a reasonable return on equity and a regulatory construct that provides for recovery of our prudent investments and reasonable costs is crucial. This MYRP outlines a path forward that provides these critical elements, while also preserving Commission oversight and ensuring just and reasonable rates for our customers.

A. Leading the Clean Energy Transition

Q. PLEASE DISCUSS THE COMPANY'S FIRST STRATEGIC PRIORITY – LEADING THE CLEAN ENERGY TRANSITION – AND WHAT THAT MEANS FOR NSPM.

A. NSPM has been a leader in renewable energy for many years, and we have long been committed to meeting our customers' increasing demands for cleaner energy sources. We took that leadership to a new level when we became the first utility in the nation to announce a goal of serving customers with 100 percent carbon-free electricity by 2050. Others have now joined in this vision as state policies and broader market forces encourage us to complete the transition of our generation fleet away from coal to renewables and other carbon-free resources in the long term.

We also appreciate that the extent and pace of this transition must be balanced with containing costs, maintaining reliability, preserving fuel diversity, investing in the grid, and providing a greater diversity of energy options that our customers demand. And we understand the importance of working with our host communities and our employees through this process.

We have been on this clean energy path for a long time now and have a successful track record of reducing our environmental footprint while maintaining outstanding reliability, keeping our customers' bills affordable, and working with our communities and employees to manage through this transition.

Q. HAS THE COMPANY ENGAGED IN OTHER EFFORTS TO LEAD THE CLEAN ENERGY TRANSITION?

A. Yes. As Company witness Mr. Paul Johnson discusses, NSPM has recently issued "Green" First Mortgage Bonds. These are fixed-income instruments earmarked to raise money for the kind of climate and environmental projects our customers and other stakeholders have encouraged us to pursue. These green bonds bring global attention to the advances Minnesota has made on renewable energy. They also diversify the Company's investor base and attract environmentally-focused investors, increasing investor demand during a bond issuance. More demand puts added pressure on investors to accept a lower price, which can benefit the Company and our customers.

Q. HOW DO THE COMPANY'S EFFORTS TO LEAD THE CLEAN ENERGY TRANSITION AND REDUCE CARBON EMISSIONS RELATE TO THIS RATE CASE FILING?

A. Our carbon reduction goals and our work to lead the clean energy transition underlie several aspects of the rate filing, as they directly impact both our capital investments and our operation and maintenance (O&M) expenses over the next three years. I will highlight three areas where this connection can be seen, and our business area witnesses discuss these impacts (and others) in more detail in their testimony. The three areas include: our continued transition to more renewable energy generation in our fleet; our industry leading nuclear operations; and our investments in our distribution system assets.

Q. HOW DO THE COMPANY'S ADDITIONAL INVESTMENTS IN RENEWABLE ENERGY GENERATION IMPACT THIS FILING?

A. The Company has long led the industry with respect to renewable energy, and we have just completed the largest build-out of wind resources in our Company's history, after the Commission's approval of our 1,850 MW wind portfolio in 2017. In addition, in the past two years, the Company has repowered an additional 170 MW of existing wind projects and obtained Commission approval for a 790 MW repowered wind portfolio for our system. By the end of the MYRP we propose here, wind will provide nearly 30 percent of the electricity for our customers in this region, making it the largest component of our overall generation portfolio.

Our work to increase our renewable portfolio impacts this filing in two principal ways: first, as Company witness Mr. Benjamin Halama and I discuss, we propose to "roll in" to base rates certain projects currently being recovered through the Renewable Energy Standard (RES) Rider. While this roll in does not actually increase customer bills, since recovery is already occurring through the rider, it does impact the base rate increases during the MYRP.

Second, as Mr. Capra explains, our proposed MYRP reflects our increased emphasis on renewable energy, in the form of both capital investments and O&M impacts. In 2021 alone, we project capital additions of over $535 million on a Minnesota jurisdictional basis net of IA for the Freeborn and Dakota Range wind farms. While these additions impact base rates, they also mean we will continue to lessen our use of fossil fuel facilities, reducing our fuel costs. Those reductions, reflected in the fuel cost adjustment (FCA) going forward, help us maintain the overall affordability of energy. And as renewable energy sources make up a larger share of our fleet, a larger part of our O&M budget will go toward maintenance of those facilities, with reductions in the O&M budget for our fossil fuel facilities.

Q. WHY ARE THE COMPANY'S PLANNED CAPITAL INVESTMENTS AND O&M EXPENSES RELATED TO ITS NUCLEAR FLEET ALSO IMPORTANT TO THE COMPANY'S CARBON REDUCTION EFFORTS?

A. As Mr. Gardner discusses, the Monticello Nuclear Generating Plant (Monticello) and Prairie Island Nuclear Generating Plant Units 1 and 2 (Prairie Island) comprise over half of our existing carbon-free generation and one-third of our total generation. These plants generate enough energy to serve more than one million customer homes. They play a critical role in our work to reduce our carbon emissions and achieve our goal of an 80 percent reduction in carbon emissions by 2030 and to provide 100 percent carbon-free energy by 2050. As Mr. Gardner discusses, we understand that the future of our nuclear fleet depends on our ability to deliver safe and reliable performance at a reasonable cost, and our nuclear employees have responded. Mr. Gardner describes our efforts to implement wide-scale changes in the way we approach nuclear plant operation and the success of those efforts. To maintain our high level of performance, and to continue delivering safe, reliable, efficient power to our customers, we must appropriately invest in these plants. Mr. Gardner discusses the necessary equipment investments and costs, as well as their overall reasonableness.

Q. AND FINALLY, HOW DO THE COMPANY'S INVESTMENTS IN ITS CORE DISTRIBUTION AND TRANSMISSION ASSETS SUPPORT THE OVERALL EFFORT ON LEADING THE CLEAN ENERGY TRANSITION AND HOW DOES THAT INITIATIVE RELATE TO THIS FILING?

A. As discussed in detail in both our previous IDP (Docket No. E002/M-19-666) as well as our soon-to-be-filed November 1, 2021 IDP (Docket No. E002/M-21-694), the Company has embarked on a long-term strategic plan to transform our distribution system to advance the efficiency and reliability of service and to safely integrate more distributed resources into our system. This initiative, along with other investments in our distribution system discussed by Company witness Ms. Kelly Bloch, is necessary to meet new demands being placed on electric utility distribution systems compared to the demands of ten or twenty years ago. This work will build an advanced electric grid that's more resilient and provides more tools and options for customers. In addition, our investments in transmission infrastructure continue to be critical in bringing renewable energy to the markets we serve.

Q. CAN YOU SUMMARIZE HOW CUSTOMERS BENEFIT FROM THESE AND SIMILAR COMPANY EFFORTS TO LEAD THE CLEAN ENERGY TRANSITION?

A. Customers benefit in multiple ways. By investing in renewable energy sources, customers not only receive the environmental benefits of low-emissions electric generation, but also enjoy long-term savings on their bills through reduced fuel costs. Investing in these resources now can keep prices affordable into the future. Through sound management of our nuclear fleet, customers receive a substantial portion of their electricity needs from safe, reliable, efficient and non-carbon emitting plants that provide energy around the clock. Finally, the Company's investments in its distribution system will provide system-wide benefits that can lead to increased service quality, faster outage restoration, and overall reductions in energy use and related emissions.

B. Enhancing the Customer Experience

Q. CAN YOU ELABORATE ON THE COMPANY'S WORK TO IMPROVE THE CUSTOMER EXPERIENCE AND HOW THAT IS REFLECTED IN THIS FILING?

A. Many of our customers want the same things they have always wanted – safe, reliable, affordable electric service. However, there is also a growing segment of our customers who expect their energy provider to play a greater role in facilitating new technologies, protecting the environment, and engaging with them regarding their energy usage. Important considerations for these customers include:

- Emerging technologies – customers are increasingly interested in evolving technologies, such as electric vehicles, home energy management, battery storage, and solar.
- Clean energy – customer interest in renewable energy continues to grow.
- Improved communications – as enhanced customer service experiences have become the expectation across a variety of industries, our customers increasingly expect that same level of service from their utility.
- Increased ability to control their energy use – customers want the information and ability to make decisions about their energy service and easily compare services and products.

To be the trusted energy provider for all our customers, we need to meet these demands.

Q. AND HOW ARE THE COMPANY'S EFFORTS TO ENHANCE THE CUSTOMER EXPERIENCE REFLECTED IN THIS FILING?

A. Our customer experience efforts are reflected in the testimony of a number of Company witnesses:

- Mr. Randy Capra describes Xcel Energy's investments in renewable energy and the O&M expenses needed to meet customer demand for clean, carbon-free energy.
- Ms. Kelly Bloch discusses the need for investments in our distribution system, particularly given the different demands being placed on that system by our customers compared to the demands historically placed on the system and explains the distribution O&M forecast.
- Mr. Michael Remington discusses the need for additional information systems capital investments to support these new demands and customer expectations and also explains the Business Systems O&M forecasts.
- Mr. Christopher Cardenas discusses anticipated Customer Care O&M expenses and savings associated with certain of our customer experience initiatives and how those savings are incorporated into the MYRP.

C. Maintaining Affordability

Q. HOW DOES THE COMPANY'S THIRD STRATEGIC PRIORITY – MAINTAINING AFFORDABILITY – RELATE TO YOUR OVERARCHING VISION AND OTHER PRIORITIES?

A. Affordability is a cornerstone of our business. If the energy we deliver is safe, clean and reliable, but it is not affordable, then the Company will not succeed in remaining a trusted and preferred provider. And we understand that maintaining affordability is even more critical in times of economic uncertainty and hardship, such as that caused by the ongoing COVID-19 pandemic.

Q. ARE THERE SPECIFIC ACTIONS THE COMPANY IS TAKING TO MAINTAIN AFFORDABLE BILLS FOR ITS CUSTOMERS?

A. Yes, there are several. First, as part of our "Relief and Recovery" efforts, the Company proposed rate mitigation measures and true-ups in late 2020 that allowed us to leave base rates at current levels for 2021. As part of that "stay-out" package, we committed to not seeking recovery of any COVID-19 pandemic related costs, including bad debt costs, for which the Commission had already approved deferred accounting. The Company also committed to paying the full $17.5 million of bill credits proposed in the residential payment plan credit program, agreed to spread recovery of the sales true-up from the demand class over 21 months, rather than 12, and agreed to an earnings cap.

Second, in this case, the Company is offering an interim rate alternative package, as discussed further below, that would significantly reduce the level of interim rates the Company would collect in 2022, if that reduction is coupled with a 2022 sales true-up and 2023 interim rates.

Third, the Company has undertaken a series of steps to mitigate the magnitude of the rate increases included in this MYRP, and those efforts are reflected throughout the witness testimony in this case. For example, on the financial side of the business, as Mr. Johnson discusses, our work to maintain a strong credit rating reduces our cost of capital, leading to lower customer bills for the long term. Similarly, multiple business area witnesses explain that we responsibly invest in our core and supporting assets with an eye to the future.

Sound investments now can provide us the platform to efficiently meet our customers' expectations, such as better enabling them to control and reduce their energy usage, or maintaining or improving reliability, while adding distributed energy resources to our system.

Fourth, through our "Steel for Fuel" strategy, we have invested in new wind projects, and we continue to invest in solar energy projects, locking in fuel savings for our customers for decades to come.

And, of course, the Company devotes significant attention to energy efficiency efforts, helping our customers save significant energy and money over the years, while also reducing carbon emissions.

Collectively, our recent efforts to maintain affordability have resulted in customers' overall bills that remain well below the national average.

D. Meeting the Challenges of a Changing Landscape

Q. WHAT CHALLENGES DOES THE COMPANY FACE IN WORKING TO ACHIEVE ITS GOALS?

A. To realize our goals, the Company must overcome a number of challenges, including:

- Dealing with the pace (and expense) of innovation in a way that responds to stakeholder needs yet also preserves affordability and the flexibility to adapt to changing needs and technologies
- Preserving and modernizing our critical infrastructure
- Continuing to attract capital at a reasonable cost

- Managing continued sales stagnation, in the long run, through electrification efforts

Q. PLEASE DISCUSS THE FIRST OF THESE CHALLENGES.

A. A key challenge for the Company is to navigate the pace, and short-term expense, of innovation in a way that responds to stakeholder needs yet also preserves both affordability and the ability to adapt to ever-changing needs and technologies. We are working to replace (or in some cases simply retire) certain aging core assets and add new core and supporting assets that can deliver immediate benefits to our customers, while at the same time providing a flexible platform that can continue to provide new and enhanced benefits over time.

Q. YOU MENTIONED THE NEED TO PRESERVE AND MODERNIZE CRITICAL INFRASTRUCTURE. HOW IS THE COMPANY RESPONDING TO THIS NEED, AND HOW DOES THAT RESPONSE AFFECT THIS FILING?

A. We cannot meet our strategic priorities without preserving and modernizing our aging infrastructure – and we are working to do so on several fronts. We must invest in new generation such as wind and solar, in the transmission resources necessary to deliver the energy from these facilities, and in our nuclear facilities that provide the critical baseload carbon-free resources our customers need. Mr. Capra discusses these issues from the Energy Supply perspective and Mr. Gardner addresses the Nuclear Operations needs during the MYRP. Moreover, as Company witnesses Mr. Ian R. Benson and Ms. Bloch discuss, our transmission and distribution infrastructure is aging and requires substantial investments in asset health to remain reliable and to provide the level and variety of services our customers expect. And as Mr.

Remington describes, our supporting information technology infrastructure is reaching obsolescence and must be refreshed and upgraded to ensure that we have the appropriate technological support as we look toward the future.

Q. AND WHY IS ATTRACTING CAPITAL AT REASONABLE COST SO CRITICAL FOR THE COMPANY AND ITS CUSTOMERS?

A. The Company is pursuing an industry-leading plan to provide carbon-free energy via advanced grid infrastructure. This plan aligns with Minnesota policy and our customers' interests. However, the Company cannot transform its fleet, address its aging infrastructure, improve the customer experience and continue to provide safe, reliable and environmentally responsible energy without investments in its core assets and supporting systems. That means the Company will have an ongoing need to access capital and, if we are to maintain our affordability, that capital must come at a reasonable cost.

Company witnesses Mr. Johnson and Mr. D'Ascendis discuss the value of a regulatory framework that provides for an appropriate capital structure and appropriate return on equity for the Company, to enable the necessary access to the capital markets. As I discussed earlier, a regulatory framework that provides a reasonable return on equity not only signals to the Company and the investment community that the Commission supports our clean energy direction, it will allow NSPM to maintain its strong credit ratings. Strong credit ratings, in turn, lead to lower costs of debt that help keep energy prices affordable. The relationship between just and reasonable rate outcomes and affordable capital is direct and impactful. The MYRP we propose in this case provides the kind of sound regulatory framework, and incentive for the

Company to control costs within that framework, that can provide long-term energy affordability.

Q. FINALLY, HOW DOES CONTINUED STAGNATION OR REDUCTION IN SALES LEVELS PUT CHALLENGES ON THE COMPANY?

A. First, I would note that there is a good news side to this story. Minnesota generally, and the Company specifically, have worked hard to be leaders in energy efficiency efforts, and we have succeeded. Of course, the work to drive down use per customer also drives down total sales which, in the absence of significant customer growth, puts revenue pressure on the Company. NSPM is not alone in this regard. Generally speaking, while the COVID-19 pandemic caused some short-term deviations from past trends, especially on a class-by-class basis, there is continued downward pressure on sales and use per customer across the industry. Over the last several years, improved energy efficiency technologies have reduced electricity demand growth and changed the amount of electricity used by an individual customer. At the same time, distributed generation and other self-generation technologies have become more accessible as material costs continue to come down. As a result, utility customers are not only able to use less but also produce their own electricity. Customer growth or new and emerging technologies such as electric vehicles or beneficial electrification can partly counteract these trends, but today's electric utilities cannot simply "grow" their way out of rate cases and such growth would run counter to important state policies such as energy efficiency and greenhouse gas emissions reductions.

Q. SO WHY IS THE COMPANY CONTINUING TO INVEST IN A STAGNANT OVERALL SALES ENVIRONMENT?

A. We provide an essential service that profoundly impacts our 1.5 million customers and our communities. Whether or not sales grow, we must make the necessary investments in our core and supporting infrastructure to continue providing energy to our customers safely and reliably.

Q. HOW DOES THE STAGNANT OR DECLINING SALES ENVIRONMENT IMPACT THIS RATE FILING?

A. Similar to our past two rate cases, declining sales necessarily means that we must recover our investments over fewer units of sales, creating a significant portion of our test year revenue requirement. In addition, as with our past two rate cases and in the 2020 and 2021 stay-outs, we propose a sales true-up as Company witness Ms. Jannell E. Marks discusses and I discuss further below. Such a true-up is a critical component of any MYRP for the Company.

E. Summary

Q. PLEASE SUMMARIZE THE BENEFITS YOU SEE IN THE COMPANY'S VISION AND BUSINESS PLAN AND ITS EFFORTS TO MEET THE CHALLENGES OF THE CURRENT INDUSTRY LANDSCAPE.

A. For customers, our vision – and plan for achieving it – assures safe, reliable, clean and affordable electric service while at the same time creating opportunities for them to benefit from new technologies and services. For regulators and policy makers, this vision and plan builds on our collective policy achievements to date and maintains Minnesota's position at the forefront of energy policy. For the Company, this vision and plan provide a path certain for the near future, while positioning us to adapt to emerging circumstances. The MYRP presented here supports the realization of all of these benefits.

III. THE COMPANY'S THREE-YEAR MULTI-YEAR RATE PLAN

A. Overview

Q. PLEASE SUMMARIZE THE COMPANY'S THREE-YEAR MYRP REQUEST IN THIS PROCEEDING.

A. The Company requests approval of a three-year MYRP, with a test year of calendar year 2022 (2022 test year) and plan years of calendar years 2023 and 2024 (2023 plan year and 2024 plan year, respectively).

Q. WHAT IS THE FINANCIAL IMPACT OF THE COMPANY'S THREE-YEAR REQUEST?

A. Our three-year MYRP demonstrates a test year 2022 net revenue deficiency of $396.0 million, a 2023 plan year net incremental revenue deficiency of $150.2 million and a 2024 plan year net incremental revenue deficiency of $131.2 million, for a total net incremental revenue deficiency of $677.3 million. The Company also proposes to roll the cost recovery of certain projects from the Transmission Cost Recovery (TCR) and RES Riders into base rates, but to do so coincident with the implementation of final rates. Mr. Halama provides the revenue requirement schedules supporting this request.

Q. CAN YOU SUMMARIZE THE FINANCIAL DRIVERS OF THE COMPANY'S MYRP REQUEST?

A. Yes. Mr. Halama discusses the key drivers behind the 2022-2024 revenue deficiency in more detail, but in addition to declining sales, the most significant drivers are as follows:

- *Ongoing investments in carbon free electrical generation.* These include investments and expenses related to our nuclear plants, in renewable energy and in our transmission system so that we can bring additional renewable energy to our customers. Mr. Gardner, Mr. Capra and Mr. Benson discuss these investments and expenses in more detail in their testimonies.
- *Investments to keep our core plants, substations, poles and wires operating reliably for the future.* Mr. Capra, Mr. Benson and Ms. Bloch all discuss our need to address certain aging infrastructure and to do so in a way that ensures safe, reliable and clean energy for our customers.
- *Increased costs of business.* While we have achieved O&M reductions in some areas, we continue to experience increased costs across much of our business.

Q. DO THE 2023 AND 2024 PLAN YEARS HAVE SIMILAR REVENUE DEFICIENCY DRIVERS AS THE 2022 TEST YEAR?

A. Yes. Although the 2023 and 2024 plan year deficiencies are driven less by the Company's investments in carbon-free energy, which impact the 2022 test year to a greater degree. Mr. Halama provides a schedule showing the drivers for these years, and each applicable business unit witness specifically addresses the needs and drivers as well.

Q. HAS THE COMPANY TAKEN ANY STEPS TO NARROW THE ISSUES IN THIS CASE?

A. Yes. In developing this case, we sought to build on the lessons learned in the 2016 MYRP and to avoid litigating certain issues that have been previously resolved by the Commission in a consistent manner. For example, our MYRP proposal includes customer protections and true-ups based on the 2016-2019 MYRP approved mechanisms and the 2020 and 2021 stay-outs. We also avoided the use of escalators in this MYRP, as those proved contentious in our last rate case. In addition, the test year sales true-up we propose can again avoid litigating the issue of the test year sales forecast. Finally, we have excluded from our request certain items that we view as reasonable and necessary to the provision of service to our customers but that the Commission has disallowed in the past, such as aviation and certain long-term incentive compensation expenses. This approach narrows the issues in this proceeding and allows parties to focus on analyzing the merits of our proposed MYRP.

Q. COULD YOU FURTHER DISCUSS THE ITEMS THE COMPANY HAS REMOVED FROM ITS RATE REQUEST?

A. Yes. The Company has proactively removed a number of items from its request. Mr. Halama discusses these items in detail in his discussion of the "precedential adjustments" and the "rate case adjustments" we made in preparing and submitting our proposed revenue requirements for these three years. These include items such as: aviation cost, fifty percent of our investor relations expenses, portions of our long-term incentive compensation and annual incentive compensation plans and other items. Collectively, the "precedential adjustments" and incentive compensation adjustments amount to over $80 million dollars over the course of our proposed MYRP, as shown in Mr. Halama's testimony.

Q. WHAT IS THE SIGNIFICANCE OF THESE ITEMS FROM THE STANDPOINT OF THE COMPANY?

A. These are reasonable and necessary expenses that enable us to provide the quality and reliability of service our customers and the Commission expect. The Company will incur these expenses. By already "adjusting" our revenue requirement, the Company has foregone the ability to recover these expenses from customers, so shareholders will pay for them rather than our customers. Any further "adjustments" to our revenue requirements will simply add to the challenge of continuing to meet our customers' and other stakeholders' needs.

Q. DOES THE COMPANY PROPOSE ANY SIGNIFICANT RATE DESIGN CHANGES AS PART OF ITS REQUEST?

A. Not with respect to general revenue apportionment or general intra-class rate design issues. Instead, as discussed by Company witness Mr. Nicholas Paluck, we seek modest movements toward cost in our rate structure and are proposing a $1.50 increase to the fixed monthly customer charge for residential and small commercial customers.

B. Basic Structure of the 2022-2024 MYRP Request

Q. BEFORE EXPLAINING THE STRUCTURE OF THE COMPANY'S MYRP, PLEASE DESCRIBE THE COMMISSION'S MYRP ORDER AND THE CURRENT MYRP STATUTE.

A. After the initial MYRP Statute was passed into law, but prior to extensive amendments to that statute, the Commission undertook an investigation to develop the terms, conditions and procedures for multi-year rate plans (Docket No. E,G999/M-12-587). At the conclusion of that investigation, the Commission issued the MYRP Order, which principally found: (1) a utility can seek to recover the costs for specific capital projects, and, as appropriate, non-capital costs in the second and third year of the multi-year rate plan; and (2) multi-year rate plans can be no longer than three years. The MYRP Order also provided requirements about the information a utility must include in an application for a multi-year rate plan, and the notices to be provided to the utility's customers.

Q. DID THE MYRP STATUTE CHANGE AFTER THE COMMISSION ISSUED ITS MYRP ORDER?

A. Yes. The MYRP Statute was amended during the 2015 legislative session and supplanted some of the points covered by the MYRP Order.

Q. WHAT ASPECTS OF THE CURRENT MYRP STATUTE WOULD YOU LIKE TO HIGHLIGHT?

A. The MYRP Statute:

- Allows the utility to request the recovery of all of its capital and O&M costs;
- Allows for up to two years of interim rate recovery;
- Allows for tariffs that expand products and services available to customers;
- Can require performance measures and incentives that are, among other things, consistent with state energy policies; and
- Can allow for the adjustment of rates under a multi-year rate plan as needed.

Q. WHEN THE COMPANY DEVELOPED THIS MYRP REQUEST, DID IT CONSIDER BOTH THE COMMISSION'S MYRP ORDER AND THE MYRP STATUTE AS AMENDED?

A. Yes. As with our 2015 MYRP proposal, our current rate request incorporates concepts from both the MYRP Order and the MYRP Statute, as shown in the completeness matrix I have attached as Exhibit___(GPC-1), Schedule 2. The Company notes that there are several aspects of the MYRP Order which were not addressed by the amended MYRP Statute. For matters addressed by the MYRP Order, but not addressed in the statute, the Company tried to tailor its proposal to match the MYRP Order. For matters addressed directly by the MYRP Statute and that provide greater flexibility than the MYRP Order to craft a plan that is in the public interest, our rate request utilizes some of these tools, consistent with those used and approved by the Commission in the 2016-2019 MYRP.

Q. CAN YOU DISCUSS THE COMPANY'S OVERALL APPROACH AND THE STRUCTURE OF YOUR MYRP REQUEST?

A. Our MYRP request utilizes a traditional test year format for the 2022 test year. As a result, we are requesting to recover our forecasted capital and O&M for 2022. For the 2023 and 2024 plan years, we use this same approach, rather than using escalators for our O&M expenses as we proposed in our 2015 rate case. We have supported our request by including our full capital and O&M forecasts for 2023 and 2024 in Volumes 5 and 6 of our Initial Filing and through the pre-filed testimony and schedules of various business area witnesses. We have also included our five-year forecast and cost of service in Volume 3, Section II, Part 8 of our filing.

C. Walk Through of MYRP Request

1. 2022 Test Year and 2023 and 2024 Plan Years

Q. HOW HAS THE COMPANY STRUCTURED THE REVENUE REQUIREMENTS PORTION OF ITS MYRP REQUEST?

A. As Mr. Halama discusses in detail, all three years of this MYRP use a traditional test year approach to rate setting. This means we are relying on our capital and O&M forecasts to prove the representative nature of the test year and of each plan year. Additionally, as I previously noted, the Company wishes to avoid re-litigating certain issues recently decided or consistently decided in the same manner by the Commission and has adjusted our revenue requirement request accordingly. Our intent in taking this approach was to create an opportunity to have a focused and constructive discussion of our MYRP proposal. Mr. Halama and our other witnesses provide the detailed support for our 2022, 2023, and 2024 forecasts. Below, I support the overall structure of the MYRP and further explain how our MYRP proposal results in just and reasonable rates.

a. Capital Investments

Q. HOW HAS THE COMPANY REFLECTED ITS EXPECTED CAPITAL INVESTMENTS IN THE THREE-YEAR MYRP?

A. We used our capital forecasts for all three years of our MYRP to develop the capital portion of the cost of service.

Q. WHY IS THIS A REASONABLE APPROACH?

A. This approach is reasonable for several reasons. First, the MYRP Statute allows for the recovery of "the utility's forecasted rate base," which must include the "utility's planned capital investments and investment-related costs, including income tax impacts, depreciations, and property taxes…" This recovery can be based on a budget forecast, which is the approach taken by the Company and was the approach taken in the Company's past two rate cases.

Second, as Company witness Ms. Melissa Ostrom discusses, the Company's budgeting process is iterative, rigorous, and leads to forecasts that reasonably represent the Company's investments during the forecasted period. Therefore, our capital budgets provide a sound basis on which to set rates.

Third, the Company's business area witnesses have described their respective business plans that drive the key investments forecasted for their areas in 2022, 2023, and 2024. While the Company acknowledges that not every forecasted capital project will play out as we currently envision, our business areas have a business plan and will pursue projects to accomplish those plans during the MYRP period. Each business area's capital forecast is aligned with its business plan and as a result the forecast provides a representative picture of the capital investments that will occur during the MYRP period.

Fourth, the Company utilized this approach in developing its MYRP proposal in the 2015 rate case and the Company's capital forecasts provided the underlying support for the 2016-2019 MYRP. When combined with the capital true-up, which we propose to use again in this proceeding, the Commission can have confidence that customers are receiving the benefits of prudent capital investments.

Q. CAN THE COMMISSION BE ASSURED THAT THE COMPANY WILL NOT OVER-COLLECT FOR ITS CAPITAL INVESTMENTS DURING THE MYRP?

A. Yes. As I discuss further below, the Company proposes a capital true-up mechanism modeled after the mechanism approved by the Commission for the 2016-2019 MYRP. This capital-related revenue requirements true-up is a "one-way" true-up. The Company will make refunds if its capital-related revenue requirements, in any year, fall below the Commission-approved capital-related revenue requirements, but cannot surcharge customers if the reverse holds true. This approach provides the Company with flexibility to manage its business while protecting customers from any "over-budgeting" by the Company.

Q. IS THE COMPANY'S RECOMMENDATION THAT THE COMMISSION APPROVE THIS "CAPITAL TRUE-UP" FOR THE ENTIRETY OF THE COMPANY'S THREE-YEAR MYRP?

A. Yes. Our filing demonstrates the reasonableness of our capital forecasts and the reliability of these forecasts for rate setting, with or without such a "true-up" process. With that being said, we believe there is value in advancing a customer protection mechanism (*i.e.*, aggregate true-up with refund) similar to that used in the 2016-2019 MYRP.

Q. DOES THE COMPANY'S THREE-YEAR MYRP REQUEST, WITH RESPECT TO ITS CAPITAL PROJECTS, INCORPORATE THE IMPACTS OF THE PASSAGE OF TIME?

A. Yes. We developed our three-year MYRP request by using a full cost of service model for the 2022 and 2024 plan years. By using a full cost of service for both years, we have captured all changes in plant balances, depreciation expense, and accumulated depreciation during 2022 and 2024, and as a result, we have fully reflected the revenue requirement impacts of the passage of time. Company witnesses Mr. Halama and Mr. Mark P. Moeller discuss this further in their respective Direct Testimonies.

b. Operations and Maintenance

Q. HOW HAS THE COMPANY ADDRESSED O&M EXPENSES IN THIS MYRP PROPOSAL?

A. In contrast to our 2015 rate case MYRP request, which used forecasted O&M for the test year but escalators for our O&M expenses in the plan years, the Company used forecasted O&M for the plan years in this proceeding. Use of escalators proved contentious in the last case. To avoid such controversy in this proceeding, we provide our full O&M forecasts for the test year and for the 2023 and 2024 plan years. Similar to our support for the capital related portion of our requests, Ms. Ostrom discusses our budgeting and forecasting process generally and our business area witnesses discuss the drivers for O&M expenses throughout the MYRP years in their testimonies.

c. Sales revenues

Q. HOW DOES THE COMPANY REFLECT ITS SALES THROUGH THE COURSE OF THE MYRP?

A. Company witness Ms. Marks provides the Company's sales forecast for 2022-2024. As Ms. Marks and I discuss, given the length of time this proceeding will last, 2022 test year revenues can be set to reflect actual test year sales. For the 2023 and 2024 plan years, we recommend that base rates be set based on the forecasts for those years provided by Ms. Marks, with a sales true-up as discussed below.

d. Other Cost Recovery Issues

Q. DOES THE MYRP PROPOSED BY THE COMPANY ALSO INCLUDE COST RECOVERY THROUGH THE AMORTIZATION OF CERTAIN EXPENSES?

A. Yes. Certain expenses such as rate case expenses or deferred expenses are not ongoing O&M expenses but are nevertheless part of the cost of service. For all but the Aurora Distributed Solar, LLC (Aurora) issue discussed below, we propose to amortize these items over three years, since we plan to file our next rate case to coincide with the end of the MYRP.

Q. AND DOES THE COMPANY ALSO PROPOSE RECOVERY OF A PORTION OF THE AURORA POWER PURCHASE AGREEMENT (PPA) THAT WAS DENIED BY THE STATE OF SOUTH DAKOTA?

A. Yes. By way of background, the Commission selected a solar project to be developed by Aurora and then approved a PPA between the Company and Aurora in Docket No. E002/CN-12-1240. The Company opposed this project due to its high cost. This resource was disputed by the South Dakota Public Utilities Commission (SDPUC) in Docket No. EL16-037 as being too expensive. In that docket, the SDPUC prohibited the Company from recovering the full South Dakota portion of Aurora. Instead, the SDPUC limited recovery from South Dakota ratepayers to an energy proxy price (derived from the system average cost of fuel and purchased power), with no capacity component.

The Company therefore requests authorization to recover the difference between the contracted PPA and the SDPUC proxy price for the period January 1, 2017 (the date the SDPUC denied recovery) to January 1, 2022, through this case. We request recovery of these costs over the two-year period from January 1, 2022 to December 31, 2023 and then to include this portion of the cost of Aurora in the FCA beginning January 1, 2024.

Q. WHY SHOULD THIS COMMISSION ALLOW RECOVERY OF THESE COSTS?

A. Given the background I reference above, the Company should be allowed full recovery of the costs of this project. Recovery of this portion of the cost of the Aurora PPA from our Minnesota customers is reasonable and appropriate. Mr. Halama addresses the adjustment necessary to provide this recovery in his testimony.

e. Revenues and Margins

Q. DID THE COMPANY INCORPORATE OFFSETTING REVENUES THAT LOWER THE MYRP REVENUE REQUIREMENTS?

A. Yes. By developing each of our MYRP years' revenue requirements using a full cost of service approach, we are capturing the full array of issues that impact those revenue requirements – both items that increase revenue requirements and items that decrease them. Mr. Halama discusses this further in his testimony.

f. Rate of Return

Q. DOES THE MYRP STATUTE ADDRESS TREATMENT OF A UTILITY'S COST OF CAPITAL DURING THE TERM OF ITS PLAN?

A. Yes. The MYRP Statute specifically provides that the Commission "may allow the utility to adjust recovery of its cost of capital or other costs in a reasonable manner within the plan period."

Q. WHY MIGHT SUCH AN ADJUSTMENT BE REASONABLE AS PART OF A MYRP?

A. Under a MYRP, utilities, regulators, customers and others are entering into a lengthy rate compact. Typically, the utility is not allowed to come back for additional revenues until the conclusion of the multi-year rate plan. This restriction places increased risk on the utility, which, in turn, could increase the utility's required ROE. Additionally, other external factors could influence the Company's required ROE over the term of the plan, such as rising interest rates. To recognize that a utility's required ROE may change (either rising or falling) during the term of a multi-year rate compact, many jurisdictions apply an adjustment mechanism during later years of the plan.

Q. IS THE COMPANY PROPOSING AN ADJUSTMENT MECHANISM TO APPLY TO ITS REQUESTED 10.20 PERCENT ROE DURING THE TERM OF THE MYRP?

A. Yes. As discussed by Company witness Mr. Timothy Lyons, of ScottMadden, Inc., the Company proposes an adjustment mechanism for the 2024 plan year, and potentially beyond if the Company does not file another rate case at the conclusion of the MYRP. This mechanism could increase or decrease the approved ROE if key underlying financial indicators have changed significantly by that time. We believe such a mechanism reasonably balances the interests of the Company and our customers and is an enhancement to our last MYRP. We also propose that this mechanism be applied in rider proceedings, to provide increased regulatory efficiencies in those filings.

g. Rate Design

Q. DOES THE COMPANY PROPOSE ANY SIGNIFICANT RATE DESIGN CHANGES DURING THE TERM OF THE MYRP?

A. No. Mr. Paluck discusses the Company's overall approach to rate design, including our approach to the 2023 and 2024 plan years, in his testimony. In general, we have adopted the same approach to both revenue apportionment and rate design in the plan years as we did for the 2022 test year.

2. Other MYRP Request Features

a. Performance Metrics

Q. DOES THE COMPANY CURRENTLY HAVE "PERFORMANCE METRICS" IN PLACE TO ASSURE CONTINUED STRONG PERFORMANCE DURING THE TERM OF ITS MYRP?

A. Yes. The Company has a strong foundation in place to assure strong performance in those areas of concern to our customers, most notably through our Quality Service Plan (QSP) Tariff. Our QSP tariff is the result of extensive negotiations with the Department of Commerce, Office of the Attorney General and the Suburban Rate Authority and was approved by the Commission. The QSP tariff is penalty-based and tracks eight metrics including: reliability, customer complaints, call response time, billing accuracy, and others. The Commission has ongoing oversight of our QSP Tariff through our annual reports.

Q. IS THE COMPANY PROPOSING ADDITIONAL PERFORMANCE MEASURES TO BE PUT IN PLACE DURING THE TERM OF THE MYRP?

A. Not in this case. While we included such performance incentive measures in our 2019 and 2020 rate case filings, which were ultimately withdrawn, we have not included any such measures here. The Commission and parties have now invested significant effort in the Commission's Performance Based Ratemaking Docket, Docket No. E002/CI-17-401 (PBR docket). We recommend that the next steps on performance-based ratemaking occur in that docket, rather than introducing another issue in this rate case proceeding.

b. Riders

Q. IS THE COMPANY PROPOSING TO REMOVE ANY ITEMS FROM ITS CURRENT RES RIDER DURING THE TERM OF ITS THREE-YEAR MYRP PROPOSAL?

A. Yes. Mr. Halama discusses the Company's proposed ratemaking treatment associated with each of the riders in use, including the Company's proposal to move recovery of a number of projects currently being recovered in riders to base rates, coincident with implementation of final rates in this proceeding. Those include the following projects:

- Blazing Star I Wind;
- Blazing Star II Wind;
- Community Wind North;
- Crowned Ridge Wind;
- Courtenay Wind;
- Dakota Range I and II;
- Freeborn Wind;
- Foxtail Wind;
- Jeffers Wind;
- Lake Benton Wind; and
- Mower Wind.

These projects are all in service or projected to be in service by December 31, 2021. There are no other projects currently being recovered through the RES Rider, though we propose to begin recovery of Northern Wind, Nobles Wind Repower, Grand Meadows Wind Repower, Border Winds Repower, and

Pleasant Valley Wind Repower projects in the RES Rider beginning January 1, 2022. These requests will be included in a forthcoming RES Rider filing and are not included in this rate case.

Q. WHY IS THE COMPANY STILL SEEKING TO RECOVER THE COSTS RELATED TO THESE PROJECTS THROUGH THE RES RIDER?

A. We appreciate that the MYRP Order encourages the transitioning of cost recovery from riders to base rates. With these new projects, however, the RES Rider provides greater certainty and accuracy around cost recovery. This is because the majority of the revenue requirement impact of these projects will occur beyond the test year of 2022. By leaving recovery of these projects in the RES Rider, we simplify the 2023 interim rate issues. Including these projects in the RES Rider also is beneficial for customers because they only pay for projects as they are actually in-serviced, and they receive the benefits from tax credits as they are generated.

Q. IS THE COMPANY ALSO PROPOSING TO MOVE RECOVERY OF CERTAIN TCR RIDER PROJECTS INTO BASE RATES WITH THE IMPLEMENTATION OF FINAL RATES?

A. Yes. As Mr. Halama discusses in more detail, we propose to move the three CapX2020 LaCrosse projects, CapX2020 Brookings, CapX2020 Fargo, Big Stone – Brookings, LaCrosse – Madison, and Huntley-Wilmarth projects from TCR Rider recovery to base rate recovery coincident with implementation of final rates in this rate case.

Q. DOES THE COMPANY PROPOSE TO CONTINUE THE TCR RIDER DURING THE MYRP?

A. Yes. Specifically, the Company requests continued recovery of the Advanced Distribution Management System (ADMS) project through the TCR Rider. This is a large qualifying project that is not yet fully in-service, making continued rider recovery appropriate. We also propose to begin recovery of the Advanced Metering Infrastructure (AMI), Field Area Network (FAN) and LoadSEER projects, as well as the Time of Use (TOU) Pilot, in the TCR Rider effective January 1, 2020. These requests will be included in a forthcoming TCR Rider filing and are not included in this rate case. We also request to continue recovery of the MISO RECB Schedule 26 and 26A net revenues through the TCR Rider.

Q. FOR THE RES OR TCR PROJECTS MOVING TO BASE RATES, WHY IS THE COMPANY PROPOSING TO ROLL THESE PROJECTS IN AT FINAL RATE IMPLEMENTATION INSTEAD OF AT THE OUTSET OF THIS CASE?

A. At the outset, it is important to recognize that there is no net impact to customers from the Company recovering the project costs through the TCR, or RES Riders, or base rates. It is just the mechanics of the recovery that changes. With that understanding, we believe that rolling these projects into base rates coincident with implementation of final rates is a reasonable approach and consistent with general ratemaking principles. It is also worth noting that continued recovery of these projects through the TCR and RES Riders during the interim rate period is relatively simple and straightforward and mirrors the approach taken with the TCR Rider in the Company's 2015 rate case.

Q. CAN YOU BRIEFLY DESCRIBE THE COMPANY'S APPROACH FOR ROLLING THESE PROJECTS INTO BASE RATES DURING FINAL RATE IMPLEMENTATION?

A. Our approach starts with an interim rate adjustment that excludes these projects from interim rates. When we implement final rates, which will include the projects in base rates, we will simultaneously remove these projects from the TCR and RES Rider mechanisms and reduce our recovery through those Riders. This approach is consistent with the Commission's treatment of Metropolitan Emission Reduction Project (MERP) costs recovered through the Environmental Improvement Rider (EIR) and the Nobles Wind, Grand Meadows Wind, and Wind2Battery projects recovered through the RES Rider in our 2010 rate case (Docket No. E002/GR-10-971).

Q. WHAT DOES THE COMPANY PROPOSE WITH REGARD TO OTHER RIDERS?

A. Consistent with our last case, we propose to continue the use of the Renewable Development Fund (RDF) Rider, CIP Rider, Renewable*Connect Rider, and the FCA in their current forms.

Q. ARE THE COMPANY'S RIDER PROPOSALS CONSISTENT WITH THE MYRP ORDER AND STATUTE AND WITH THE 2016-2019 MYRP?

A. Yes. Consistent with the MYRP Order, the Company proposes to move a number of in-service projects from rider recovery to base rate recovery. Other projects will remain in riders for recovery during the MYRP, and new qualifying projects may be added. This approach is reasonable and consistent with the MYRP Statute, which specifically allows utilities proposing MYRPs to propose adjustments for significant investments during the term of the plan.

From a policy perspective, MYRPs and riders can be viewed as complementary to one another. In an environment of flat sales and ongoing, needed capital investments, base rates can provide the necessary recovery of those core investments, while riders can focus on discrete qualifying projects or new policy-driven initiatives, which may require more frequent oversight and scrutiny. When used together in this way, a MYRP and riders can provide stable, predictable, consistent rate recovery for a sustained period of time, while encouraging pursuit of policy goals. The 2016-2019 MYRP accomplished that result, and the Company's proposed MYRP can as well.

c. Cost Recovery of Pilots

Q. DID THE COMMISSION RECENTLY ADDRESS THE ISSUE OF COST RECOVERY ASSOCIATED WITH PILOT PROGRAMS INITIATED DURING A MYRP?

A. Yes. In Docket No. E002/M-18-643, the Commission approved deferred accounting for certain pilot program expenses related to the Company's Fleet EV Service Pilot and Public Charging Pilot. In its Order, the Commission also required the Company "to address in its next rate case filing how it intends to handle and budget for future pilots prior to its following rate case filing."

Q. WHAT DOES THE COMPANY INTEND WITH RESPECT TO PILOTS DURING THE MYRP PERIOD?

A. There is no "one size fits all" solution for how pilots and cost recovery for those pilots should be handled. If the Company determines or is required to offer a new pilot, we will examine the specific program and assess available cost recovery options. Any petition we file for approval of the pilot will fully discuss any cost recovery proposal associated with it, and Commission approval would be required before cost recovery could occur. This approach is consistent with the MYRP Order, which states that "the Commission will address petitions for riders and deferred accounting on a case-by-case basis as they arise and will consider the status and objectives of the petition."

d. Proposed True-ups During the Term of the MYRP

Q. DOES THE COMPANY PROPOSE ANY "TRUE-UP" MECHANISMS DURING THE TERM OF ITS PLAN?

A. Yes. The Company proposes true-ups modeled after the true-ups approved in the Company's 2015 rate case for our current MYRP, and I discuss the policy rationale for these true-ups below. Much like our last case, this case is likely to transpire such that we will have the benefit of having actual test year information about our sales prior to calculating and implementing final rates. Consistent with the 2016-2019 MYRP, we recommend setting final rates based on actual 2022 test year weather normalized sales and then using a sales true-up for the 2023 and 2024 plan years, as was done in the 2016-2019 MYRP and the 2020 and 2021 stay-outs. We also recommend using true-ups for our capital related revenue requirements and property taxes throughout the MYRP.

e. Sales True-up

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED TEST YEAR SALES TRUE-UP.

A. As Ms. Marks discusses, the Company proposes a true-up of the Company's sales for the 2022 test year, as was done in the Company's last two rate cases. This true-up is integral to our MYRP proposal, as it ensures that rates will be set properly during the test year.

Q. WHY IS THE SALES TRUE-UP SO INTEGRAL TO YOUR MYRP PROPOSAL?

A. First, it is important to recognize the role of sales and the sales forecast in a general rate case. As Ms. Marks discusses, the goal of the sales forecast as used in a rate case is to best predict the ultimate sales that the Company will experience. However, sales forecasts often become contentious issues in rate cases, given their impact on revenue requirements. For example, if the sales forecast projects lower sales than the utility ultimately achieves, rates will have been overstated; all else equal, and customers will have paid more than necessary for the Company to earn its authorized return. Conversely, if the sales forecast is overstated, rates will be set too low, and the utility will be denied a reasonable opportunity to earn its authorized return.

To set base rates appropriately and treat both customers and the Company fairly, in the Company's past two rate cases, the parties agreed to utilize actual data to inform the proceeding, rather than relying exclusively on one or the other of the competing forecasts. Given the length of time those cases took to process, full test year sales data was available to set final rates. We expect that the same will be true in this proceeding. By the time of completion of this proceeding, the Company will have full test-year sales data available and there will simply be no need to rely on a test-year forecast; which, absent perfection in the forecast, would necessarily lead to rates being set too high or too low.

Q. DOES THE COMPANY ALSO PROPOSE AN ONGOING SALES TRUE-UP?

A. Yes. However, rather than a combination of a sales true-up (for demand customer classes) and revenue decoupling mechanism (for other classes), as was approved in the 2016-2019 MYRP, the Company proposes a sales true-up for all classes. The Company's decoupling pilot expired at the end of 2019. Therefore, in approving the Company's 2020 and 2021 stay-out petitions, the Commission approved use of the sales true-up for all customer classes. The Company proposes to use this same methodology as a permanent decoupling mechanism, with minor changes as explained by Company witness Nicholas Paluck. Decoupling is a tool that helps to align interests in policy matters such as conservation and demand response, as well as offers revenue stabilization as we implement innovative rate design changes such as our proposal for three-period time of use pricing. Our proposal for an ongoing decoupling mechanism will help ensure that neither customers nor the Company are financially harmed when actual results diverge from the forecast, and will provide a reasonable opportunity to maintain Company revenue at the level authorized by the Commission.

f. Capital True-up

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CAPITAL TRUE-UP.

A. The Company proposes a capital true-up designed in conformance with that used in the 2016-2019 MYRP and previously approved by the Commission in our 2013 rate case (Docket No. E002/GR-13-826). Under this mechanism, the Company will provide a refund to customers if the Company's actual capital-related revenue requirement is less in total, in any of the MYRP years, than the Commission authorizes for that year. Conversely, if the Company's actual capital-related revenue requirement is more in total, in an MYRP year, than the Commission authorizes for that year, the Company cannot surcharge customers to collect that difference.

Q. WHY IS SUCH A CAPITAL TRUE-UP MECHANISM REASONABLE?

A. From the customers' perspective, this capital true-up provides protection and assurance that the Company will not over-collect for its capital investments during the term of the MYRP. From the Company's perspective, although we have demonstrated the reasonableness of our capital forecasts in this rate filing, we see the value in offering this ratepayer protection and, by focusing the true-up on total capital-related revenue requirements, we retain the flexibility to manage our business during the term of the MYRP.

g. Property Tax True-up

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED PROPERTY TAX TRUE-UP.

A. As with the capital true-up, the Company proposes a property tax true-up designed in conformance with that used in the 2016-2019 MYRP and previously approved by the Commission in our 2013 rate case. As Mr. Christopher A. Arend discusses, given the expected procedural schedule for this case, we believe it may be possible to set final rates based on actual property taxes for 2022 rather than relying on a forecast. Alternatively, final rates can be set based on the Company's property tax forecast for 2022 and the Company would make a compliance filing once final 2022 property taxes are known, so that any over-recovery could be refunded, or any under-recovery could be deferred. Going forward, 2023 and 2024 rates would be set based on forecasted property tax amounts. However, the Company would submit annual compliance filings that show actual property taxes for those years once they are finalized.

Q. WHY IS A PROPERTY TAX TRUE-UP REASONABLE AS PART OF THE MYRP?

A. While the Company strives to develop the best property tax forecasts it can, there is always uncertainty about the finality of state Department of Revenue valuations each year. Therefore, final property taxes could be higher or lower than our forecasts. A symmetrical true-up mechanism, as was used in the 2016-2019 MYRP, allows the Company to recover this necessary cost of providing service and ensures customers only pay the actual property tax amounts for a given year.

h. Compliance Filings/Status Reports

Q. WHAT DOES THE MYRP ORDER ENVISION REGARDING COMMISSION REVIEW DURING THE TERM OF AN MYRP AND WHAT DOES THE COMPANY PROPOSE IN THIS REGARD?

A. The MYRP Order directs utilities to propose a process for filing and a schedule for reviewing reports that compared the estimated costs and revenues for the plan years to the actual costs and revenues experienced and to explain the reasons for any difference so that the Commission and parties can evaluate the accuracy of the estimates used in the MYRP rate making process. The compliance filings the Company proposes to make and a proposed schedule for review of those filings is provided in Exhibit___(GPC-1), Schedule 3. These filings, together with the Company's sales and decoupling true-up reports, and our May 1 Jurisdictional Annual Report (JAR), will ensure ongoing regulatory oversight and provide the Commission and parties a wealth of information on which to assess the Company's performance under the MYRP.

i. Commitment to Not File During Term of Plan

Q. THE MYRP ORDER STATES THAT A UTILITY MAY NOT FILE A NEW RATE CASE DURING THE TERM OF AN APPROVED MYRP. DOES THE COMPANY AGREE?

A. Yes. As I have already discussed, one of the benefits of a just and reasonable MYRP plan is that it can provide more stable and predictable rates for a period of time and avoid the need for serial rate case filings. If the Commission approves another MYRP for the Company, we would not file a new rate case during the term of the plan.

j. Rates at the Conclusion of the Plan

Q. THE MYRP ORDER REQUIRES A UTILITY TO "EXPLAIN THE RATES THAT IT PROPOSES TO BE IN EFFECT" AT THE END OF THE PLAN. WHAT DOES THE COMPANY PROPOSE IN THIS REGARD?

A. Rates during the final year of the MYRP would remain in effect at the conclusion of the term of the MYRP (subject to any approved ROE adjustment mechanism as recommended by Mr. Lyons), unless the Company files another MYRP 60 days prior to the conclusion of the term and proposes new interim rates.

3. Conclusion

Q. HOW CAN THE COMMISSION HAVE CONFIDENCE THAT THE COMPANY'S RATES WILL BE JUST AND REASONABLE UNDER YOUR MYRP REQUEST?

A. Our three-year MYRP is built on a full cost of service approach. For the capital-related portions of this request, the MYRP relies on our capital forecasts, which are established through a rigorous process and have proven to be conservative over time. Our business area witnesses and supporting documentation also provide significant discussion of the main capital drivers over the three-year term of the plan. By utilizing the full cost of service approach, we have also fully captured the impact of the passage of time throughout the MYRP period. Finally, we propose an overall capital-related revenue requirements true-up that will provide refunds to customers should we not invest at the levels forecasted.

For expense items, we have also employed a full cost of service approach in this case, again supported by our forecasts and by our business area witnesses. Given our full cost of service approach, we also have incorporated revenue or other offsets, including forecasted O&M reductions in areas such as our nuclear operations and customer care, that reduce our revenue requirements in the plan years. This approach has resulted in modest and stable rate requests for the 2023 and 2024 plan years that should assure the affordability of our energy services over the term of the plan.

Finally, the Commission will receive a wealth of information, in the form of compliance filings, true-up filings and our jurisdictional annual report, by which it can review the impact on customers as well as our performance and our financial results.

Collectively, this package provides assurance that our rates will be just and reasonable throughout the term of our plan.

D. Interim Rate Request

Q. WHAT IS THE COMPANY'S INTERIM RATE REQUEST?

A. The Company's interim rate increase request is detailed in Volume 1 of our Application. We are requesting the Commission approve an interim rate increase of approximately $288.3 million beginning January 1, 2022. We expect this proceeding could last until into the 2022 calendar year. For that reason, and consistent with the MYRP Statute, we propose an additional interim rate increase beginning January 1, 2023 of $135 million, meaning a total interim rate increase for 2023 of $423 million.

Q. WHY IS INTERIM RATE RECOVERY IMPORTANT?

A. In order to meet our customers' and other stakeholders' needs and expectations for the continued delivery of clean, safe, reliable energy, our revenues need to be adjusted on an interim basis so we can recover the costs that have been incurred and will be spent during this proceeding. For example, a sizable amount of our 2022 request relates to investments that will be in-service before final rates are likely to be in effect.

Q. IS THERE ANYTHING YOU WOULD LIKE TO NOTE ABOUT THE COMPANY'S INTERIM RATE REQUEST?

A. The Company's interim rate request for 2022 is substantially lower than our final base rate request because we are keeping certain recoveries in riders during the pendency of the case and then rolling those projects in to base rates at the conclusion of the proceeding. We discuss this further in Mr. Halama's testimony and in the Notice and Petition for Interim Rates, included in Volume 1.

Q. WHY IS IT REASONABLE TO HAVE A SECOND INTERIM RATE INCREASE IN 2023?

A. Based on the statutory timeline for our case and our experience in our last rate case, we do not anticipate a final order in this case in 2023. This means that we will still be making increasing investments and facing increased costs in

2023. To be positioned to meet our customers' needs, an interim rate increase is appropriate and the MYRP Statute specifically allows for such an increase.

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO ITS 2022 INTERIM RATE REQUEST?

A. We have made adjustments to our interim rate request required by Minnesota law, such as reflecting our currently authorized ROE, as well as a few additional adjustments, such as removing the impact of the projects currently being recovered in our TCR or RES Riders, but proposed to be rolled into final rates at the conclusion of this proceeding. Again, these adjustments are addressed in our Notice and Petition for Interim Rates.

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO ITS 2023 INTERIM RATE REQUEST?

A. We took the same approach to our 2023 interim rates as we did to our 2022 interim rate request.

Q. DOES THE COMPANY OFFER AN ALTERNATIVE INTERIM RATE PACKAGE FOR THE COMMISSION TO CONSIDER?

A. Yes. If the Commission sees value in mitigating the size of the interim rate increase in 2022, the Company can agree to an alternative interim rate package that would lower the Company's interim rate revenue requirement for 2022 from $288.3 million to $190.1 million. Specifically, the Company can agree to remove the impact of lower sales from interim rates for both 2022 and 2023 and continue to use a sales true-up for those years instead, meaning the Company would defer collection of any lost sales revenues by a year. This would also reduce the incremental interim rate level for 2023, leading to a total interim rate increase of $306 million under the Company's alternative proposal, compared to $423 million under standard interim rates. The Company stresses that the viability of this alternative interim rate package hinges on the Commission's approval of the 2023 interim rate level requested, adjusted to remove the impact of lost sales. Given the investments needed to be made in 2022 and 2023, the Company cannot agree to such a significant reduction in interim rate levels for 2022 without certainty that it will gain additional revenue relief beginning January 1, 2023.

IV. FRAMEWORK OF FILING AND COMPLETENESS MATRIX

Q. CAN YOU EXPLAIN HOW THE INITIAL FILING IS ORGANIZED IN THIS CASE?

A. Yes. The filing consists of multiple volumes, as follows:

- Volume 1 contains our Notice of Change of Rates and Interim Rate Petition.
- Volumes 2A through 2D include the Direct Testimony and supporting schedules of each of the witnesses.
- Volume 2E contains our proposed Tariff sheets for the 2022 test year and the 2023 and 2024 plan years.
- Volume 3 includes the Required Financial Information, providing that information in support of each of the three years of our MYRP rate request and includes our five-year forecast and cost of service, so that parties and the Commission have the benefit of this information in determining the appropriate MYRP for the Company.

- Volume 4 includes the workpapers primarily supporting the cost of service studies for the 2022 test year and 2023 and 2024 MYRP plan years, prepared at the direction of Mr. Halama.
- Volume 5 includes our Budget Summary and Documentation.
- Volume 6 includes our Budget Documentation.

Q. HAVE YOU PROVIDED A COMPLETENESS MATRIX, DEMONSTRATING THE COMPANY'S COMPLIANCE WITH ALL RATE CASE FILING REQUIREMENTS?

A. Yes. I have attached our completeness matrix as Schedule 2.

V. INTRODUCTION OF WITNESSES

Q. PLEASE INTRODUCE THE WITNESSES THE COMPANY SPONSORS IN THIS PROCEEDING.

A. In addition to my Policy testimony, the Company sponsors the following witnesses:

- Benjamin Halama, who sponsors the overall revenue requirement for the rate case. Mr. Halama also sponsors the schedules supporting our income statement, rate base, revenue deficiency, and jurisdictional allocations. His schedules incorporate and reflect the recommendations of a number of our witnesses, including the business area, cost of capital and sales forecast witnesses. Mr. Halama also supports certain cost recovery proposals.
- Paul Johnson, who sponsors our capital structure, cost of debt, and overall cost of capital recommendations and provides testimony regarding investor relations.

- Dylan D'Ascendis, of ScottMadden, Inc., who testifies on the Return on Equity and Rate of Return, including capital structure, and the cost of debt.
- Timothy Lyons, also of ScottMadden, Inc., who testifies on multi-year rate plans and return on equity adjustment mechanisms.
- Melissa Ostrom, who testifies on the Company's budgeting process.
- Jannell Marks, who provides testimony supporting the Company's sales forecast for the 2022 test year and also testifies regarding sales in the 2023-2024 plan years. These sales figures are then used in Mr. Halama's determination of the revenue deficiency.
- Michael Remington, who testifies on the Company's overall business systems and information technology needs essential to the operations of our business, including all computer hardware, computer software, voice and data networks, and the software that facilitates the communication necessary between multiple systems.
- Kelly Bloch, who sponsors testimony regarding our investments in our distribution system, as well as associated O&M expenses.
- Christopher Cardenas, who provides testimony on the Company's customer satisfaction, actions by the Customer Care organization to contain costs while maintaining and improving customer service and the Company's commodity and non-commodity bad debt expense.
- Peter Gardner, who sponsors testimony regarding our nuclear program and the reasonableness of our nuclear-related capital investments and O&M costs.

- Ian Benson, who sponsors testimony regarding the budgeted investments in our transmission system, as well as associated O&M expenses.
- Randy Capra, who sponsors testimony discussing our capital budget and the O&M expenses for the Energy Supply business unit. Mr. Capra also provides information with respect to the performance of our generation fleet and steps we are taking to improve performance and operate more efficiently.
- Ross Baumgarten, who presents our Cost Assignment and Allocation Manual, and discusses cost allocations between business areas and jurisdictions, as well as from Xcel Energy Services Inc.
- Christopher Arend, who sponsors testimony regarding our property tax expenses and proposed property tax tracker.
- Robert Miller, who sponsors testimony regarding the Company's insurance program.
- Richard Schrubbe, who provides testimony about of our pension cost recovery request and associated pension accounting matters.
- Evan Inglis, an independent consultant, who provides a third-party opinion regarding the reasonableness of the Company's investment strategies and target asset allocations for the qualified pension funds over the past several years.
- Ruth Lowenthal, who sponsors testimony in support of our employee compensation and benefits policies, including incentive compensation. Ms. Lowenthal also provides testimony regarding our health and welfare benefits and our retirement program.
- William Husen, who sponsors testimony regarding employee expenses.

- Mark P. Moeller, who provides testimony regarding depreciation and remaining lives for all plant and plant-related items. Mr. Moeller also presents testimony regarding how the Company's MYRP request accounts for the passage of time.
- Michael Peppin, who sponsors our class cost of service study and discusses the minimum distribution study issues required to be addressed in this case.
- Nicholas Paluck, who sponsors the general rate design and tariff changes we present in this case.

VI. CONCLUSION

Q. CAN YOU PLEASE SUMMARIZE THE KEY POINTS OF YOUR TESTIMONY?

A. The Company, Commission and stakeholders have achieved a number of successes over the past six years, as the Company operated under a multi-year rate plan and, subsequently, under two stay-outs. The Company has led the industry in the clean energy transition, while maintaining safe, reliable and affordable electric service. The Commission has received a wealth of information on the Company's performance and investments over this period, to ensure just and reasonable rates. And the Commission, Company and stakeholders have worked together on many key policy matters, including navigating the transition to a carbon-free energy future, performance-based ratemaking, advanced grid initiatives and many others.

The multi-year rate plan we propose in this case can deliver similar benefits. We look forward to discussing these benefits with our stakeholders, and to continue working collectively on the important public policy issues ahead.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Greg P. Chamberlain

Vice President for Regulatory and Government Affairs
Northern States Power Company - Minnesota

Greg Chamberlain is Xcel Energy's Regional Vice President for Regulatory and Government Affairs. He is responsible for state government relations and regulatory filings with the utility commissions in Minnesota, North Dakota and South Dakota.

He previously served as Regional Vice President for Government and Community Relations for the Company, overseeing state and local government relations for Minnesota, North Dakota, and South Dakota.

Prior to that, Chamberlain served as General Manager of Power Generation, where he was responsible for the operations of the Company's fleet of 13 power plants across Minnesota, Wisconsin, and South Dakota.

As Director of Transmission Portfolio Delivery for the Company, Chamberlain was responsible for the engineering, project management, project controls and permitting of a $4 billion electric transmission capital portfolio across 10 states. In addition, he acted as Xcel Energy's management committee representative on each of four CapX2020 projects. CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region, investing $2 billion to expand the electric transmission grid to ensure continued reliable and affordable service.

Chamberlain joined Xcel Energy in 2000 as a market segment manager with responsibility for marketing power and ancillary services in newly deregulated markets, and then joined the Transmission organization in 2006.

Before joining Xcel Energy, Chamberlain spent five years at Suez leading energy, water and chemical outsourcing initiatives in a variety of heavy industries. Prior to that role, he spent nine years at Hercules, Inc., now part of Ashland Chemical.

Chamberlain earned a Master of Business Administration degree from the University of Minnesota - Carlson School of Management and a Bachelor of Science degree in chemical engineering from Purdue University. He serves on the boards of directors of Catholic Charities of St. Paul and Minneapolis and the Boy Scouts of America Northern Star Council.

Requirement	Description	Location in Application
Minn. Rule 7825.3200	**NOTICE OF CHANGE IN RATES**	
	A utility filing for a general rate change shall serve notice to the commission at least 90 days prior to the proposed effective date of the modified rates. Such notice shall include:	Vols. 1 and 2A – 2E (see below for specific requirements and locations).
	(1) proposal for change in rates as prescribed in part 7825.3500;	
	(2) modified rates as prescribed in part 7825.3600;	
	(3) expert opinions and supporting exhibits as prescribed in part 7825.3700;	
	(4) informational requirements as prescribed in parts 7825.3800 to 7825.4400; and	
	(5) statement indicating the method of insuring the payment of refunds as prescribed in part 7825.3300.	
Minn. Rule 7825.3500	**PROPOSAL FOR CHANGE IN RATES**	
	The utility's proposal for a change in rates shall summarize the notice of change in rates and shall include the following information:	
A.	name, address, and telephone number of the utility without abbreviation and the name and address and telephone number of the attorney for the utility, if there be one;	Vol. 1, Notice of Change in Rates Tab.
B.	date of filing and date modified rates are effective;	Vol. 1, Notice of Change in Rates Tab.
C.	description and purpose of the change in rates requested;	Vol. 1, Notice of Change in Rates Tab.
D.	effect of the change in rates expressed in gross revenue dollars and as a percentage of test year gross revenue; and	Vol. 1, Notice of Change in Rates Tab.
E.	signature and title of utility officer authorizing the proposal.	Vol. 1, Notice of Change in Rates Tab.
Minn. Rule 7825.3300	**METHODS AND PROCEDURES FOR REFUNDING**	

	An unqualified agreement, signed by an authorized official of the utility, to refund any portion of the increase in rates determined to be unreasonable together with interest thereon.	Vol. 1, Agreement and Undertaking Tab.
	Any increase in rates or part thereof determined by the commission to be unreasonable shall be refunded to customers or credit to customers' accounts within 90 days from the effective date of the commission order and determined in a manner prescribed by the commission including interest at the average prime interest rate computed from the effective date of the proposed rates through the date of refund or credit.	Vol. 1, Agreement and Undertaking Tab.
Minn. Rule 7825.3600	**MODIFIED RATES**	
	All proposed changes in rates shall be shown by filing revised or new pages to the rate book previously filed with the commission and by identifying those pages which were not changed. Each revised or new page of the rate book shall contain the information required for each page of the rate book and shall be in a format consistent with the currently filed rate book. In addition, each revised page shall contain the revision number and the page number of the revised page.	Vol. 2E contains the Clean and Redline versions of the tariffs to be changed, including the revision number and page number. Pages not changed are identified with an asterisk on the index page for the 2022 test year.
Minn. Rule 7825.3700	**EXPERT OPINIONS AND SUPPORTING EXHIBITS**	
	Expert opinions and supporting exhibits shall include written statements, in question and answer format, together with supporting exhibits of utility personnel and other expert witnesses as deemed appropriate by the utility in support of the proposal.	Vols. 2A, 2B, 2C, and 2D.
Minn. Rule 7825.3900	**JURISDICTIONAL FINANCIAL SUMMARY SCHEDULE**	
	A jurisdictional financial summary schedule as required by part 7825.3800 shall be filed showing:	
A.	the proposed rate base, operating income, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the test year;	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, Schedules 2-3 (Revenue Requirements);

		Vol. 3, Section II, Tabs 2 to 5.
B.	the actual unadjusted average rate base consisting of the same components as the proposed rate base, unadjusted operating income, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the most recent fiscal year; and	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, Schedules 7-8 (Revenue Requirements); Vol. 3, Section II, Tabs 2 to 5.
C.	the projected unadjusted average rate base consisting of the same components as the proposed rate base, unadjusted operating income under present rates, overall rate of return, and the calculation of income requirements, income deficiency, and revenue requirements for the projected fiscal year.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, Schedules 7-8 (Revenue Requirements); Vol. 3, Section II, Tabs 2 to 5.
Minn. Rule 7825.4000	**RATE BASE SCHEDULES**	
	The following rate base schedules as required by part 7825.3800 shall be filed:	
A.	A rate base summary schedule by major rate base component (e.g. plant in service, construction work in progress, and plant held for future use) showing the proposed rate base, the unadjusted average rate base for the most recent fiscal year and unadjusted average rate base for the projected fiscal year. The totals for this schedule shall agree with the rate base amounts included in the financial summary.	Vol. 3, Section II, Tab 3, Parts A to E.
B.	A comparison of total utility and Minnesota jurisdictional rate base amounts by detailed rate base component showing:	
	total utility and the proposed jurisdictional rate base amounts for the test year including the adjustments, if any, used in determining the proposed rate base;	Vol. 3, Section II, Tab 3, Part B.
	the unadjusted average total utility and jurisdictional rate base amounts for the most recent fiscal year and the projected fiscal year.	Vol. 3, Section II, Tab 3, Part B.
C.	Adjustment schedules, if any, showing the title, purpose, and description and the summary calculations of each adjustment used in determining the proposed jurisdictional rate base.	Vol. 3, Section II, Tab 3, Part C.

D.	A summary by rate base component of the assumptions made and the approaches used in determining average unadjusted rate base for the projected fiscal year. Such assumptions and approaches shall be identified and quantified into two categories: known changes from the most recent fiscal year and projected changes.	Vol. 3, Section II, Tab 3, Part D.
E.	For multijurisdictional utilities only, a summary by rate base component of the jurisdictional allocation factors used in allocating the total utility rate base amounts to the Minnesota jurisdiction. This summary shall be supported by a schedule showing for each allocation factor the total utility and jurisdictional statistics used in determining the proposed rate base and the Minnesota jurisdictional rate base for the most recent fiscal year and the projected fiscal year.	Vol. 3, Section II, Tab 3, Part E.
Minn. Rule 7825.4100	**OPERATING INCOME SCHEDULES**	
	The following operating income schedules as required by part 7825.3800 shall be filed:	
A.	A summary schedule of jurisdictional operating income statements which reflect proposed test year operating income, and unadjusted jurisdictional operating income for the most recent fiscal year and the projected fiscal year calculated using present rates.	Vol. 3, Section II, Tab 4, Part A.
B.	For multijurisdictional utilities only, a schedule showing the comparison of total utility and unadjusted jurisdictional operating income statement for the test year, for the most recent fiscal year and the projected fiscal year. In addition, the schedule shall provide the proposed adjustments, if any, to jurisdictional operating income for the test year together with the proposed operating income statement.	Vol. 3, Section II, Tab 4, Part B.
C.	For investor-owned utilities only, a summary schedule showing the computation of total utility and allocated Minnesota jurisdictional federal and state income tax expense and deferred income taxes for the test year, the most recent fiscal year, and the projected fiscal year. This summary schedule shall be supported by a detailed schedule, showing the development of the combined federal and state income tax rates.	Vol. 3, Section II, Tab 4, Part C.

D.	A summary schedule of adjustments, if any, to jurisdictional test year operating income and detailed schedules for each adjustment providing an adjustment title, purpose and description of the adjustment, and summary calculations.	Vol. 3, Section II, Tab 4, Part D.
E.	A schedule summarizing the assumptions made and the approaches used in projecting each major element of operating income. Such assumptions and approaches shall be identified and quantified into two categories: known changes from the most recent fiscal year and projected changes.	Vol. 3, Section II, Tab 4, Part E.
F.	For multijurisdictional utilities only, a schedule providing, by operating income element, the factor or factors used in allocating total utility operating income to Minnesota jurisdiction. This schedule shall be supported by a schedule which sets forth the statistics used in determining each jurisdictional allocation factor for the test year, the most recent fiscal year, and the projected fiscal year.	Vol. 3, Section II, Tab 4, Part F.
Minn. Rule 7825.4200	**RATE OF RETURN COST OF CAPITAL SCHEDULES**	
	The following rate of return cost of capital schedules as required by part 7825.3800 shall be filed:	
A.	A rate of return cost of capital summary schedule showing the calculation of the weighted cost of capital using the proposed capital structure and the average capital structures for the most recent fiscal year and the projected fiscal year. This information shall be provided for the unconsolidated parent and subsidiary corporations, or for the consolidated parent corporation.	Vol. 3, Section II, Tab 5, Part A.
B.	Supporting schedules showing the calculation of the embedded cost of long-term debt, if any, and the embedded cost of preferred stock, if any, at the end of the most recent fiscal year and the projected fiscal year.	Vol. 3, Section II, Tab 5, Parts B & E LTD and PE.
C.	Schedule showing average short-term securities for the proposed test year, most recent fiscal year, and the projected fiscal year.	Vol. 3, Section II, Tab 5, Part C STD.

	Average Common Equity Balances (Additional Information)	Vol. 3, Section II, Tab 5, Part D CE.
Minn. Rule 7825.4300	**RATE STRUCTURE AND DESIGN INFORMATION**	
	The following rate structure and design information as required by part 7825.3800 shall be filed:	
A.	A summary comparison of test year operating revenue under present and proposed rates by customer class of service showing the difference in revenue and the percentage change.	Vol. 3, Section II, Tab 6, Part A.
B.	A detailed comparison of test year operating revenue under present and proposed rates by type of charge including minimum, demand, energy by block, gross receipts, automatic adjustments, and other charge categories within each rate schedule and within each customer class of service.	Vol. 3, Section II, Tab 6, Part B.
C.	A cost-of-service study by customer class of service, by geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class of service, geographic area, or other appropriate category, identifying the procedures and underlying rationale for cost and revenue allocations. Such study is appropriate whenever the utility proposes a change in rates which results in a material change in its rate structure.	Vol. 3, Section II, Tab 6. Part C
		Michael A. Peppin, Exhibit___(MAP-1), Vol. 2D, pgs 8-45 and Schedules 2 to 9 (CCOSS).
Minn. Rule 7825.44	**OTHER SUPPLEMENTAL INFORMATION**	
	The following supplemental information as required by part 7825.3800 shall be filed:	
A.	Annual report to stockholders or members including financial statements and statistical supplements for the most recent fiscal year. If a utility is not audited by an independent public accountant, unaudited financial statements will satisfy this filing requirement.	Vol. 3, Section II, Tab 7, Part A.

B.	For investor-owned utilities only, a schedule showing the development of the gross revenue conversion factor.	Vol. 3, Section II, Tab 7, Part B.
C.	For cooperatives only, REA Form 7, Financial and Statistical Report for the last month of the most recent fiscal year.	Not Applicable.
D.	For cooperatives only, REA Form 7A, Annual Supplement to Financial and Statistical Report.	Not Applicable.
E.	For REA cooperatives only, REA Form 325, Financial Forecast.	Not Applicable.
Minn. Rule 7829.2400	**FILING REQUIRING DETERMINATION OF GROSS REVENUE**	
Subpart 1.	**Summary.** A utility filing a general rate case or other filing that requires determination of its gross revenue requirement shall include, on a separate page, a brief summary of the filing, sufficient to apprise potentially interested parties of its nature and general content	Vol. 1, Notice of Change in Rates Tab.
Subp. 2.	**Service.** A utility filing a general rate change request shall serve copies of the filing on the department and Residential Utilities Division of the Office of the Attorney General. The utility shall serve the filing or the summary described in subpart 1 on the persons on the applicable general service list and persons who were parties to its last general rate case or incentive plan proceeding.	Vol. 1, Notice of Change in Rates Tab.
Subp. 3.	**Notice to public and governing bodies.** A utility seeking a general rate change shall give notice of the proposed change to the governing body of each municipality and county in its service area and to its ratepayers. The utility shall also publish notice of the proposed change in newspapers of general circulation in all county seats in its service area.	Vol. 1, Notice of Change in Rates Tab.
MINNESOTA STATUTES		
Minn. Stat. § 216B.16, subd. 17	**TRAVEL, ENTERTAINMENT, AND RELATED EMPLOYEE EXPENSES**	

	(a) The commission may not allow as operating expenses a public utility's travel, entertainment, and related employee expenses that the commission deems unreasonable and unnecessary for the provision of utility service. In order to assist the commission in evaluating the travel, entertainment, and related employee expenses that may be allowed for ratemaking purposes, a public utility filing a general rate case petition shall include a schedule separately itemizing all travel, entertainment, and related employee expenses as specified by the commission, including but not limited to the following categories:	Vol. 3, Section IV, Part 2 Travel, Entertainment & Related Employee Expenses.
	(1) travel and lodging expenses;	Vol. 3, Section IV, Part 2 EER Summary Report 1.
	(2) food and beverage expenses;	
	(3) recreational and entertainment expenses;	
	(4) board of director-related expenses, including and separately itemizing all compensation and expense reimbursements;	Vol. 3, Section IV, Part 2 EER, Schedule 4.
	(5) expenses for the ten highest paid officers and employees, including and separately itemizing all compensation and expense reimbursements;	Vol. 3, Section IV, Part 2 EER, Schedule 5.
	(6) dues and expenses for memberships in organizations or clubs;	
	(7) gift expenses;	
	(8) expenses related to owned, leased, or chartered aircraft; and	
	(9) lobbying expenses.	
	(b) To comply with the requirements of paragraph (a), each applicable expense incurred in the most recently completed fiscal year must be itemized separately, and each itemization must include the date of the expense, the amount of the expense, the vendor name, and the business purpose of the expense. The separate itemization required by this paragraph may be provided using standard accounting reports already utilized by the utility involved in the rate case, in a written format or an electronic format that is acceptable to the commission. For expenses identified in response	Vol. 3, Section IV, Part 2 EER Summary Report 1 and files submitted via secure file transfer.

	to paragraph (a), clauses (1) and (2), the utility shall disclose the total amounts for each expense category and provide separate itemization for those expenses incurred by or on behalf of any employee at the level of vice president or higher and for board members. The petitioning utility shall also provide a one-page summary of the total amounts for each expense category included in the petitioning utility's test year.	
Minn. Stat. §216B.19	**MULTIYEAR RATE PLAN**	
	A utility proposing a multiyear rate plan shall provide a general description of the utility's major planned investments over the plan period. The commission may also require the utility to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies.	Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A, pgs 31-51 (Policy/MYRP Policy).
		Michael O. Remington, Exhibit___(MOR-1), Vol. 2B, pgs 8-105 (Business Systems).
		Kelly A. Bloch, Exhibit ___(KAB-1), Vol. 2B, pgs 13-110 (Distribution).
		Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 15-60 and Schedules 3 & 4 (Energy Supply).
		Peter A. Gardner, Exhibit___(PAG-1), Vol. 2B, pgs 26-106 (Nuclear Operations).
		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 10-84 and Schedules 2 & 3 (Transmission).
		William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 47-64 and Schedule 9 (Employee Expenses).
		Mark P. Moeller, Exhibit___(MPM-1), Vol. 2C, pgs 8-25 (Depreciation).

POLICY STATEMENTS		
Advertising	Statement that recovery is requested only for permitted advertisements.	Vol. 3, Section III, Tab 1.
	Description of advertisements for which recovery is requested.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 75 (Revenue Requirements).
		Vol. 4, Section VIII, Tab A1 Advertising.
	Sample advertisements for which recovery is requested.	Vol. 3, Section III, Tab 1.
Charitable Contributions	Evidence as to whether the recipients of the contributions: serve the utility's Minnesota service area; are nondiscriminatory in selecting recipients; and do not promote political or special interest groups.	Vol. 3, Section III, Tab 2.
	Evidence as to what organizations are gifted, their activities, and that no part of the contribution goes to benefit any private stockholder or individual.	Vol 3, Section III, Tab 2.
	Itemized schedule showing amount, recipient and time of donations.	Vol 3, Section III, Tab 2.
	Only 50% of qualified contributions shall be allowed as operating expenses.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 55 n.6, 75 (Revenue Requirements); Vol 3, Section III, Tab 2; Vol. 4, Section VIII, Tabs A6 and A7 Foundation and Other Donations and Economic Development Donations.
Organization Dues	Schedule showing each organization being paid, the number of employees belonging to each organization and the dollar amount of dues being paid to each organization.	Vol. 3, Section III, Tab 3.
	Testimony explaining the primary purpose of each organization.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A pg 75 (Revenue Requirements).
		Vol. 3, Section III, Tab 3.
		Vol. 4, Section VIII, Tabs A2 and A4 Dues for Professional

		Associations and Dues for the Chamber of Commerce.
Research Expenses	Description of each research activity for which an expense is claimed, with all expenses for each activity itemized and supported.	Vol. 3, Section III, Tab 4.
Cash Working Capital	Lead/lag study with: 1) lead time divided into service to meter reading; meter reading to billing; and billing to collection; and 2) lag expenses divided in categories such as fuel, purchased power, labor.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 41-44, Schedules 3 and 4 (Revenue Requirements).
		Vol. 4, Section III, Tab P10 Cash Working Capital.
	Other issues may include average or minimum cash balances required, depreciation, dividends and interest on debt	
Interim Rates:		
Item 1, page 2	Name, address and telephone number of utility and attorneys.	Vol. 1, Interim Rate Petition Tab.
Item 2, page 2	Date of filing and date proposed interim rates are requested to become effective.	Vol. 1, Interim Rate Petition Tab.
Item 3, page 2	Description and need for interim rates.	Vol. 1, Interim Rate Petition Tab.
Item 4, page 2	Description and corresponding dollar amount change included in interim rates as compared with most current approved general rate case and with the most recent year for which audited data is available.	Vol. 1, Interim Rate Supporting Schedules and Workpapers Tab.
Item 5, page 2	Effect of the interim rates expressed in gross revenue dollars and as a percentage of test year gross revenues	Vol. 1, Interim Rate Supporting Schedules and Workpapers Tab.
Item 6, page 2	Certification by officer of the utility.	Vol. 1, Interim Rate Petition Tab.
Item 7, page 2	Signature and title of the utility officer authorizing the proposed interim rates.	Vol. 1, Interim Rate Petition Tab.
	Methods and procedures for refunding.	Vol. 1, Agreement and Undertaking Tab.
Items 1-4, page 3	Supporting schedules and workpapers.	Vol. 1, Interim Rate Supporting Schedules and Workpapers Tab.

	Modified tariffs.	Vol. 1, Interim Tariff Sheets - Redlined Tab; Vol. 1, Interim Tariff Sheets - Clean Tab.
	Notices.	Vol. 1, Interim Rate Petition Tab.
COMMISSION ORDERS IN GENERIC DOCKETS (E,G-999)		
CI-90-1008	**Commission Investigation into Appliance Sales and Service by Utilities**	
Order 3/11/1995	Demonstrate in future rate case filings that: [NSP] follows the cost allocation principles recommended by the Commission; or its non-regulated activities are insignificant; or its cost allocation principles produce similar results as would allocations following the recommended cost allocation principles; or the public interest is better served by another method.	Ross L. Baumgarten Exhibit___(RLB-1), Vol. 2C, pgs 3-9 and Schedule 3 at 23-24 (Cost Allocations).
M-12-587	**Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. § 216B.16, subd. 19**	
Order, 6/19/13	1. A utility may propose a multiyear rate plan to improve the regulatory process for the recovery of –	
Order, 6/19/13	A. Costs related to specific, clearly identified capital projects and	Michael O. Remington, Exhibit___(MOR-1), Vol. 2B, pgs 47-105 and Schedule 2 (Business Systems).
		Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 35-110, 149-176 and Schedule 2 (Distribution).
		Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 15-60 and Schedules 3 & 4 (Energy Supply).
		Peter A. Gardner, Exhibit___(PAG-1), Vol. 2B, pgs 52-106 (Nuclear Operations).

		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 30-85 and Schedules 2 & 3 (Transmission).
		William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 47-64 and Schedule 9 (Employee Expenses).
		Mark P. Moeller, Exhibit___(MPM-1), Vol. 2C, pgs 9-69 (Depreciation).
	B. Appropriate non-capital costs.	Michael O. Remington, Exhibit___(MOR-1), Vol. 2B, pgs 105-121 and Schedule 3 (Business Systems).
		Christopher C. Cardenas, Exhibit___(CCC-1), Vol. 2C, pgs 4-41 and Schedules 2, 5-6 (Customer Care and Bad Debt Expense).
		Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 111-179 and Schedule 3 (Distribution).
		Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 74-115 and Schedules 2, 5-7 (Energy Supply).
		Peter X. Gardner, Exhibit___(PAG-1), Vol. 2B, pgs 106-159 (Nuclear Operations).
		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 86-116 and Schedules 4 & 5 (Transmission).
	2. A utility may propose to implement a multiyear rate plan only as part of a general rate change subject to Minn. Stat. § 216B.16.	The Company's Application, including its multi-year rate plan proposal, is a general rate change application subject to Minn. Stat. § 216B.16.
	3. A multiyear rate plan shall not last longer than three years. A multiyear rate plan starts with the effective date of newly authorized rates in a general rate case proceeding, coinciding with the proposed test year in the rate case, unless it	The Company's multi-year rate plan is for three years. Minn. Stat. §216B.16, subd. 19 as amended in 2015 expressly allows for plans of up to five years.

	is demonstrated to be reasonable to do otherwise.	
Order, 6/19/13	4. The rate of return on equity authorized and used to set rates in the general rate case in which the multiyear rate plan is approved shall be the return on equity used to set the rate adjustments in the plan itself.	Minn. Stat. §216B.16, subd. 19 as amended in 2015 expressly provides that the Commission may allow adjustments to the cost of capital in a reasonable manner within the plan period.
		Greg P. Chamberlain, Exhibit___(GPC-1), pgs 39-40 (Policy/MYRP Policy).
		Timothy S. Lyons, Exhibit (TSL-1) (MYRP ROE).
	5. It is presumed that interim rates will be calculated based upon the rate case test year unless it is demonstrated to be reasonable to do otherwise.	Minn. Stat. §216B.16, subd. 19 as amended in 2015 expressly allows for interim rates for the utility to request interim rates for the first and second years of the plan, to be implemented in the same manner as provided in Minn. Stat. §216B.16, subd. 3.
		Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A, pgs 53-56 (Policy/MYRP Policy).
		Vol. 1, Notice & Petition for Interim Rate Tab.
Order, 6/19/13	8. A utility seeking authorization for a multiyear rate plan shall not propose formula rates that are contingent upon future developments. Rather, the utility shall identify a specific price for each regulated utility service it plans to charge for each year that the plan remains in effect.	Consistent with the MYRP statute, the Company's proposed MYRP proposes rates based on a full cost of service approach for each year of the MYRP.
		Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A, pgs 33-38 (Policy/MYRP Policy).
		Nicholas N. Paluck ___Exhibit (NNP-1), Vol. 2D, pgs 20-38 and Schedules 2-5 (Rate Design).
		Vol. 2E, Proposed Tariff Sheets.

	9. Regarding the rates to apply after the multiyear rate plan expires, the utility shall explain the rates that it proposes to be in effect thereafter. If the specific dollar amount of those rates cannot be provided, the utility should clearly explain the changes in costs and revenues that it proposes to include in those rates and how the utility proposes to calculate those rates. Alternatively, the utility may propose a new rate case under Minn. Stat. § 216B.16.	Greg P. Chamberlain Exhibit___(GPC-1) Vol 2A, pg 52 (Policy/MYRP Policy).
Order, 6/19/13	10. Where a utility is recovering continuing, predictable costs through riders, a utility seeking approval of its multiyear rate plan shall propose to recover those costs via base rates at the beginning of the rate case.	Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A, pgs 42-46 (Policy/MYRP Policy).
		Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 94-99, 104-123, 134 (Revenue Requirements).
	11. Regarding other riders and cost recovery mechanism, the utility shall design its multiyear rate plan to consolidate as many of them as practical, in the most reasonable manner available.	Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A, pgs 42-50 (Policy/MYRP Policy).
		Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 94-99, 104-123, 134 (Revenue Requirements).
	12. Commission will address new petitions for riders and deferred accounting on a case by case basis as they arise and will consider the status and objectives of the petition.	Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A, pgs 45-47 (Policy/MYRP Policy).
	13. A utility shall clearly show that its multiyear rate plan will not cause the utility to recover costs already being recovered through existing rate riders. No utility shall recover costs through a rider that it is also recovering through a multiyear rate plan for the same period.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 94-99, 104-123, 134 (Revenue Requirements).
Application Requirements	14. An application for a multiyear rate plan must include or be accompanied by an explanation of the following:	
	A. How the proposed plan conforms to and is consistent with Minn. Stat. § 216B.16, subd. 19.	Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A (Policy/MYRP Policy).

	B. How the proposed plan would improve the regulatory process for the recovery of costs related to specific, clearly identified capital projects and, to the extent appropriate, related non-capital costs.	Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A, pgs 4-10 (Policy/MYRP Policy).
Application Requirements	15. An application for a multiyear rate plan must include or be accompanied by a description of the form of the multiyear rate plan the utility is proposing and the purpose behind the choice, including–	Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A (Policy/MYRP Policy).
	A. The specific capital projects for which the utility seeks to recover capital costs – and, where appropriate, non-capital costs – via the plan,	The MYRP Statute provides for the use of capital and O&M forecasts. Mr. Chamberlain and the business area witnesses address these matters in their testimonies.
		Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A (Policy/MYRP Policy).
		Michael O. Remington, Exhibit___(MOR-1), Vol. 2B, pgs 47-121 and Schedules 2 & 3 (Business Systems).
		Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 35-179 and Schedules 2 & 3 (Distribution).
		Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 15-60, 74-115 and Schedules 2-8 (Energy Supply).
		Peter A. Gardner, Exhibit___(PAG-1), Vol. 2B, pgs. 52-159 (Nuclear Operations).
		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 30-116 and Schedules 2-6 (Transmission).
		William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 21-64 (Employee Expenses).
		Mark P. Moeller, Exhibit___(MPM-1), Vol. 2C, pgs 9-69 (Depreciation).

Application Requirements	B. The reason for the projects,	Michael O. Remington, Exhibit___(MOR-1), Vol. 2B, pgs 8-121 (Business Systems).
		Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 35-110, 149-176 (Distribution).
		Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 15-74 (Energy Supply).
		Peter A. Gardner, Exhibit___(PAG-1), Vol. 2B, pgs 52-106 (Nuclear Operations).
		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 10-85 (Transmission).
		William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 47-64 (Employee Expenses).
	C. The scope of the projects,	Michael O. Remington, Exhibit___(MOR-1), Vol. 2B, pgs 8-121 (Business Systems).
		Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 35-110, 149-176 (Distribution).
		Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 15-74 (Energy Supply).
		Peter A. Gardner, Exhibit___(PAG-1), Vol. 2B, pgs 52-106 (Nuclear Operations).
		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 10-85 (Transmission).
		William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 47-64 (Employee Expenses).
		Mark P. Moeller, Exhibit___(MPM-1), Vol. 2C, pgs 9-69 (Depreciation).

	D. The timing of the projects,	Michael O. Remington, Exhibit___(MOR-1), Vol. 2B, pgs 8-121 (Business Systems).
		Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 35-110, 149-176 (Distribution).
		Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 15-74 (Energy Supply).
		Peter A. Gardner, Exhibit___(PAG-1), Vol. 2B, pgs 52-106 (Nuclear Operations).
		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 10-85 (Transmission).
		William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 47-64 (Employee Expenses).
		Mark P. Moeller, Exhibit___(MPM-1), Vol. 2C, pgs 9-69 (Depreciation).
	E. The non-capital costs to be recovered via the plan and	Michael O. Remington, Exhibit___(MOR-1), Vol. 2B, pgs 105-121 and Schedule 3 (Business Systems).
		Christopher C. Cardenas, Exhibit___(CCC-1), Vol. 2C, pgs 4-41 and Schedules 2, 5-6 (Customer Care and Bad Debt Expense).
		Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 111-179 and Schedule 3 (Distribution).
		Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 75-115 and Schedules 2, 5-8 (Energy Supply).
		Peter A. Gardner, Exhibit___(PAG-1), Vol. 2B, pgs. 106-159 (Nuclear Operations).

		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 86-116 and Schedule 4 (Transmission).
		Mark P. Moeller, Exhibit___(MPM-1), Vol. 2C, pgs 9-69 (Depreciation).
Application Requirements	F. The reason for seeking to recover the cost of the projects via a multiyear rate plan rather than via other means.	Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A, (Policy/MYRP Policy).
Application Requirements	16. An application for a multiyear rate plan must include or be accompanied by the rates the utility proposes to charge in each year of the multiyear rate plan, stated in fixed (*i.e.,* dollar amount) terms, not formulas.	Nicholas N. Paluck ___Exhibit (NNP-1), Vol. 2D, pgs 20-38 and Schedules 2-5 (Rate Design).
		Vol. 2E Proposed Tariff Sheets.
Application Requirements	17. An application for a multiyear rate plan must include or be accompanied by all the information required for a general rate case, including but not limited to-	
	A. Jurisdictional financial summary,	Vol. 3, Section II, Tab 2.
Application Requirements	B. Rate base,	Vol. 3, Section II, Tab 3.
Application Requirements	C. Operating income,	Vol. 3, Section II, Tab 4.
Application Requirements	D. Rate of return and cost of capital schedules and	Vol. 3, Section II, Tab 5.
Application Requirements	E. Other financial schedules and cost projections filed in conjunction with a general rate change as described in Minn. R. 7825.3800 to 7825.4500.	*See generally* Vol. 3, Section II.
Application Requirements	18. An application for a multiyear rate plan must include or be accompanied by testimony supporting the following aspects of the case:	
	A. The capital additions that the utility proposes for each year of the multiyear rate plan.	Michael O. Remington, Exhibit___(MOR-1), Vol. 2B, pgs 47-105 (Business Systems).
		Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 35-110, 149-176 and Schedule 2 (Distribution).

		Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 15-60 and Schedules 3 & 4 (Energy Supply).
		Peter A. Gardner, Exhibit___(PAG-1), Vol. 2B, pgs 52-106 (Nuclear Operations).
		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 30-85 and Schedules 2 & 3 (Transmission).
		William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 47-64 and Schedule 9 (Employee Expenses).
		Mark P. Moeller, Exhibit___(MPM-1), Vol. 2C, pgs , 9-25, 31-32 (Depreciation).
Application Requirements	B. Depreciation lives related to capital additions in each year of the plan.	Mark P. Moeller, Exhibit___(MPM-1), Vol. 2C, pgs 9-61 (Depreciation).
Application Requirements	C. Changes expected in the lives of all depreciable assets for two years after the plan.	Mark P. Moeller, Exhibit___(MPM-1), Vol. 2C, pgs 8-9, 25, 34-35 (Depreciation).
Application Requirements	D. Directly related income and expense items for the plan's second and third years (as applicable), related solely to depreciation expense, property taxes, deferred taxes, state and federal taxes, allowance for funds used during construction.	Mark P. Moeller, Exhibit___(MPM-1), Vol 2C, pgs 28-48 and Schedule 7 (Depreciation).
		Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A pgs 55-64 (Revenue Requirements).
		Christopher A. Arend, Exhibit___(CAA-1), Vol. 2D, pgs 2-22 and Schedules 5-6, 10-12 (Property Tax).
Application Requirements	E. A sales forecast.	John M Goodenough, Exhibit___(JMG-1), Vol. 2A (Sales Forecast).

Application Requirements	F. A budget forecast.	The Budget Documentation provided in Volumes 3, 5 and 6 includes forecasts for the 2022 test year and the 2023 and 2024 Plan Years. Volume 3 also includes forecasts and cost of service for 2025 and 2026.
		Company witness Ms. Ostrom addresses the process used to develop the budget forecasts. Melissa L. Ostrom, Exhibit___(MLO-1), Vol. 2A, pgs 29-43 and Schedule 3 (Budgeting).
Application Requirements	G. The utility's forecasting methodology.	John M Goodenough, Exhibit___(JMG-1), Vol. 2A, pgs 38-60 and Schedules 3 to 10 (Sales Forecast).
		Melissa L. Ostrom, Exhibit___(MLO-1), Vol. 2A, pgs 29-43 (Budgeting).
Application Requirements	H. An analysis of the historical accuracy of the utility's short-term, medium-term and long-term forecasts.	John M Goodenough, Exhibit___(JMG-1), Vol. 2A, pgs 11-16, 19-21 and Schedule 2 (Sales Forecast).
		Melissa L. Ostrom, Exhibit___(MLO-1), Vol. 2A, pgs 30-31 and Schedule 3 (Budgeting).
Application Requirements	19. Regarding changes in rates and cost recovery to be implemented in the plan's second and third years (as applicable), an application for a multiyear rate plan must include or be accompanied by the following:	
	A. A list of the relevant categories of costs that will justify changes in the utility's rates in the second and third years of the plan.	Michael O. Remington, Exhibit___(MOR-1), Vol. 2B, pgs 75-121 and Schedules 2 & 3 (Business Systems).
		Christopher C. Cardenas, Exhibit___(CCC-1), Vol. 2C, pgs 4-41 and Schedules 2, 5-6 (Customer Care and Bad Debt Expense).

		Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 35-178 and Schedules 2 & 3 (Distribution).
		Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 47-60, 74-115 and Schedules 2-8 (Energy Supply).
		Peter A. Gardner, Exhibit___(PAG-1), Vol. 2B, pgs 106-159 (Nuclear Operations).
		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 30-85 and Schedules 2 & 3 (Transmission).
Application Requirements	B. A forecast of the changes in each cost category.	Michael O. Remington, Exhibit___(MOR-1), Vol. 2B, pgs 47-121 and Schedules 2 & 3 (Business Systems).
		Christopher C. Cardenas, Exhibit___(CCC-1), Vol. 2C, pgs 4-41 and Schedules 2, 5-6 (Customer Care and Bad Debt Expense).
		Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 35-178 and Schedules 2 & 3 (Distribution).
		Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 47-60, 74-115 and Schedules 2-8 (Energy Supply).
		Peter A. Gardner, Exhibit___(PAG-1), Vol. 2B, pgs 106-159 (Nuclear Operations).
		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 30-116 and Schedules 2-6 (Transmission).
Application Requirements	C. A forecast of any related offsetting revenues.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A pgs 46-47 (Revenue Requirements).
		Nicholas N. Paluck ___Exhibit (NNP-1), Vol 2D, pgs 12-19 and Schedules 2-5 (Rate Design).

		Vol. 3, Section II, Tab 6, Parts A and B.
Application Requirements	D. A process for filing and a schedule for reviewing, reports that-	
	1) compare estimated costs and revenues for the second and third years (if applicable) of the plan to the actual costs the utility incurred and the revenues the utility recovered, during the second and third years and	Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A, pg 51 and Schedule 3 (Policy/MYRP).
	2) explain the reasons for any differences to help the Commission and parties evaluate the accuracy of the cost estimates used in the multiyear rate making process.	Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A, pg 51 and Schedule 3 (Policy/MYRP).
Application Requirements	20. An application for a multiyear rate plan must include or be accompanied by a clear explanation of the rates that are proposed to be in effect at the end of the multiyear rate plan.	Greg P. Chamberlain , Exhibit___(GPC-1), Vol. 2A, pg 52 (Policy/MYRP Policy).
	A. If the utility cannot identify the specific dollar amounts of those rates, the utility shall clearly explain the changes in costs and revenues that it proposes to include in those rates and how it proposes to calculate those rates.	Nicholas N. Paluck ___Exhibit (NNP-1), Vol. 2D, pgs 20-38 and Schedules 2-5 (Rate Design).
	B. Alternatively, the utility may explain that a new rate case under Minn. Stat. § 216B.16 is necessary to establish these rates.	
Application Requirements	21. Regarding any proposal to establish new rates on an interim basis, an application for a multiyear rate plan must include or be accompanied by an explanation of how the utility proposes to collect and possibly refund interim rates in conjunction with the collection of and transition to the rates arising from a multiyear rate plan.	Vol. 1, Notice & Petition for Interim Rate Tab and Agreement and Undertaking Tab.
Application Requirements	22. Regarding an applicant's existing rate riders, an application for a multiyear rate plan must include or be accompanied by the following:	
	A. A proposal to restructure its riders as follows:	Greg P. Chamberlain, Exhibit___(GPC-1), Vol. 2A, pgs 42-47 (Policy/MYRP Policy).
		Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 94-99, 104-123, 134 (Revenue Requirements).

	1) a proposal to recover through base rates the cost of existing riders that are likely to continue and are sufficiently predictable to support recovery through base rates,	
	2) a proposal to consolidate as many other riders and cost recovery mechanisms as is practical and	
	3) a demonstration that the utility's proposals to restructure its rate riders are the most reasonable alternatives available to the utility.	
Application Requirements	B. Clear evidence that double recovery will not occur as a result of the way the utility proposes to handle its multiyear rate plan and existing riders, including evidence that the periods during which the utility is recovering a cost via a rider does not overlap with the period during which it is recovering the cost via base rates or the multiyear rate plan mechanism.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 97-99 104-123, 134 (Revenue Requirements).
		Vol. 1, Notice & Petition for Interim Rate Tab.
Application Requirements	23. Regarding conditions for obtaining approval for a multiyear rate plan, the application must include or be accompanied by the following:	
	A. A commitment to provide the Commission, parties and potentially interested persons with notice of the initial rate change and detailed financial information for the initial rate change at least 60 days before the proposed effective date of the initial rate change.	The Company has filed this case and accompanying notices 60 days in advance of any effective date of proposed initial rate changes. *See* Vol. 1, Notice of Change in Rates Tab and Notice & Petition for Interim Rate Tab.
Application Requirements	B. An acknowledgement that upward rate adjustments during the course of the multiyear plan will be subject to refund if the rate adjustment is later determined to have been imprudent and a waiver of any claim that such refunds represent retroactive ratemaking.	This Order point predates the revised MYRP Statute and reflected the Order requirement that the only adjustments allowed were for specified large capital improvement projects. The Company proposes a one-way aggregate capital true-up in this case, as was used in the 2016-2019 MYRP.

		See Greg P. Chamberlain, Exhibit___(GPC-1), Vol 2A, pgs 47-51 and Schedule 3 (Policy/MYRP Policy).
Application Requirements	C. A proposal for a process that ensures that if it became prudent to delay or avoid making a planned investment, the cost of that investment would be removed from the rates arising from the multiyear rate plan and would be refunded if already collected.	This Order point predates the revised MYRP Statute and reflected the Order requirement that the only adjustments allowed were for specified large capital improvement projects. The Company proposes a one-way aggregate capital true-up in this case, as was used in the 2016-2019 MYRP. See Greg P. Chamberlain, Exhibit___(GPC-1), Vol 2A, pgs 47-51 and Schedule 3 (Policy/MYRP Policy).
Customer Notice	24. In addition to the notices that a utility must provide to seek a general rate increase, customers shall be provided with additional customer communication and opportunities to participate in the multiyear ratemaking process.	See Vol. 1, Notice of Change in Rate Tab, Proposed Notice to Counties and Municipalities, Notice & Petition for Interim Rate Tab, and Proposed Interim Rate Bill Insert.
Customer Notice	25. A utility shall fully inform its customers about its proposal for a multiyear rate plan and the plan's effects on rates. Public hearing notices and bill inserts shall fully explain the process, the utility's proposal, the proposed duration of the plan and how the customer can participate.	Vol. 1, Notice of Change in Rate Tab, Proposed Notice to Counties and Municipalities, Notice & Petition for Interim Rate Tab, and Proposed Interim Rate Bill Insert.
Customer Notice	28. A utility shall provide notice of each rate change when the change becomes effective. Sixty days before the initial rate change is proposed to take effect, the utility shall provide the Commission, parties and potentially interested persons with notice of the change and detailed financial information.	The Company has filed this case and accompanying notices 60 days in advance of any effective date of proposed initial rate changes. *See* Vol. 1, Notice of Change in Rates Tab and Notice & Petition for Interim Rate Tab.
Compliance Filings	29. A utility applying for or operating under a multiyear rate plan shall do the following:	This Order point predates the revised MYRP Statute and reflected the Order requirement that the only adjustments allowed were for specified large capital

		improvement projects. The Company proposes a one-way aggregate capital true-up in this case, as was used in the 2016-2019 MYRP. See Greg P. Chamberlain, Exhibit___(GPC-1), Vol 2A, pgs 47-51 and Schedule 3 (Policy/MYRP Policy).
	A. File annual status reports confirming that the utility has made investments according to its multiyear rate plan and affirming that it still intends to make the future investments authorized as part of the plan.	
Compliance Filings	B. If a project included in a multiyear rate plan is canceled or postponed, within 30 days inform the Commission and parties, file a proposal to adjust rates to stop collecting any costs related to the canceled or postponed project and refund costs already collected.	This Order point predates the revised MYRP Statute and reflected the Order requirement that the only adjustments allowed were for specified large capital improvement projects. The Company proposes a one-way aggregate capital true-up in this case, as was used in the 2016-2019 MYRP. See Greg P. Chamberlain, Exhibit___(GPC-1), Vol 2A, pgs 47-51 and Schedule 3 (Policy/MYRP Policy).
Compliance Filings	C. If a utility makes some other material change in plans, file a status report promptly (e.g., within 30 days of the known change).	This Order point predates the revised MYRP Statute and reflected the Order requirement that the only adjustments allowed were for specified large capital improvement projects. The Company proposes a one-way aggregate capital true-up in this case, as was used in the 2016-2019 MYRP. See Greg P. Chamberlain, Exhibit___(GPC-1), Vol 2A, pgs 47-51 and Schedule 3 (Policy/MYRP Policy).

Compliance Filings	D. Within 180 days after the final rate adjustment under the multiyear rate plan, make a compliance filing verifying that the rates charged under the plan were based only on reasonable and prudent costs of service.	This Order point predates the revised MYRP Statute and reflected the Order requirement that the only adjustments allowed were for specified large capital improvement projects. The Company proposes a one-way aggregate capital true-up in this case, as was used in the 2016-2019 MYRP. See Greg P. Chamberlain, Exhibit___(GPC-1), Vol 2A, pgs 47-51 and Schedule 3 (Policy/MYRP Policy).
COMMISSION ORDERS IN XCEL ENERGY DOCKETS (E002 or G002)		
GR-91-1	**1991 General Electric Rate Case**	
Order, 11/27/91	The Company shall incorporate the DRI index, or a comparable industry standard, as a guideline in future rate cases.	Volume 5 Supplemental Budget Information, Tab 5. Inflation Trend Analysis.
	The Company shall implement the following budget requirements in its next rate case:	
	a) Besides the budget documentation filed according to the standards of this Order, the Company shall at the time of filing make support documentation available for inspection by other parties upon request. Such documentation should include workpapers and notes used in developing budgets;	In light of the COVID-19 pandemic, we are not presently making these documents available for physical examination, but should circumstances change, they may be examined during normal business hours at our General Offices located at 414 Nicollet Mall in downtown Minneapolis. For questions or to make alternative arrangements, please contact Gail Baranko at 612-330-6935.
	b) The Company shall file translation reports linking cost element, cost activity and project budgeting mechanisms on a common and consistent basis to ensure a proper audit trail;	See Budget Documentation in Vols. 5 and 6. Also see Supplemental Budget Information Volume, Budget Translation/ Analysis of Miscellaneous Expenses Tab

		provided to agencies separately in accordance with the Order in E002/GR-92-1185.
Order, 11/27/91	c) The Company shall file bridge schedules showing all adjustments used in moving from the unadjusted budget to the rate case numbers;	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, Schedules 10a-c, 11a-c, 12, and 13 (Revenue Requirements).
		Vol. 3, Section II, Part 3, Tab C and Part 4, Tab D.
	d) The Company shall provide summaries of all of its applicable budgets by FERC subaccounts. If the Company cannot comply with this requirement it shall show cause within 30 days of the date of this Order;	Vol. 3, Section IV, Part 1, FERC Sub-Account Information Tab.
	e) The Company shall include month-by-month accounting of all transactions in the contingency funds;	Vol. 5, Capital Substitutions / Contingent Process & Reports Tab.
	f) The Company shall provide a year-end summary report of project substitution with each contingency fund by project type and subject benefit.	Vol. 5, Capital Substitutions / Contingent Process & Reports Tab.
	Advantage Service shall:	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 141 (Revenue Requirements).
		NSP Advantage Service now operates under the name HomeSmart from Xcel Energy®.
	- pay a return on the use of NSP's billing services asset.	
	- compensate the Company for its personnel's referral time.	
	- pay the Company a competitive rate for use of its mailing lists.	
M-94-13	**Treatment of Emission Allowance Transactions Under Clean Air Act**	
Order, 5/12/94	Company to defer to the next rate case revenues from the sale by the EPA of emissions reserves, as well as gains from the sale of allowances and incremental transaction costs.	Given the small level in this account, the Company has made no adjustment and proposes discontinuing this deferral.

		Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 140-141 (Revenue Requirements).
AI-94-1056; AI-94-1188	**Affiliated Interest Dockets related to leases with United Power and Land Company**	
Orders, 2/14/95 & 3/17/95	NSP is required to demonstrate in future rate cases that all payments made to or by NSP as a result of its affiliated interest agreements are reasonable and that these agreements have not resulted in any ratepayer subsidization of non-regulated activities of affiliated companies.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 67 (Revenue Requirements).
		Ross L. Baumgarten Exhibit___(RLB-1), Vol. 2C, pgs 27, and Schedule 3 at 15-16 (Cost Allocations).
M-95-174	**Competitive Bidding Process**	
Order 08/05/96	NSP to track capacity-related non-performance penalties on NSP Generation projects for return to ratepayers in a future rate case.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 143 (Revenue Requirements).
GR-97-1606	**1997 General Rate Case**	
Order, 9/30/98	Tax Benefit Transfer leases included in the test year are consistent with the methodology approved in past NSP rate case orders.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 142 (Revenue Requirements).
AI-01-493	**Administrative Services Agreement between Xcel Energy Services, Inc. and Its Operating Affiliates**	
Order, 6/22/01	Provide up-front testimony demonstrating the benefits to the ratepayers (*e.g.*, sharing rail cars).	Ross L. Baumgarten Exhibit___(RLB-1), Vol. 2C, pgs 3-6, Schedule 8 (Cost Allocations).
AI-04-181	**Updated Service Agreement with Xcel Energy Services Inc.**	
Order, 8/20/04	Identify Investor Relations Costs and provide the calculations showing the allocation of these costs between ratepayers and shareholders in next rate case.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 75 and Schedules 12-13 (Revenue Requirements).
		Vol. 4, Section VIII, Tab A12 Investor Relations.

		Paul A. Johnson, Exhibit___(PAJ-1), Vol. 2A, pgs 40-42 (Capital Structure).
M-04-1956	**Low-Income Discount Program**	
Order, 9/26/14	Xcel shall file a proposal to include recovery of its Low-Income Program costs through base rates in its next rate case.	Nicholas N. Paluck ___Exhibit (NNP-1), Vol 2D, pgs 18-19 (Rate Design).
GR-08-1065	**2008 Minnesota Electric Rate Case**	
Order, 10/23/09; Order Point 9	In future electric rate case filings, Company shall include testimony and schedules of short-term and long-term capacity costs by contract and shall show how the capacity amounts were calculated.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 137 and Schedule 15 (Revenue Requirements).
Order, 10/23/09; Order Point 10	In future electric rate case filings, Company shall include information on steps it has taken to exclude from advertising expense costs related to branding and other promotional activities.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 75 (Revenue Requirements).
		Vol. 4, Section VIII, Tab A1 Advertising.
Order, 10/23/09; Order Point 12	As recommended by ALJ, Company shall use Renewable Energy Standard Rider to flow through to customers revenues from all sales of Renewable Energy Credits.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 97, 142-143 (Revenue Requirements).
Order, 10/23/09; Order Point 13	In future rate case filings, the Company shall include the sales forecast information discussed in Findings 145-148 of the Administrative Law Judge's Report.	Forecasting data was pre-filed on September 24, 2021 in Docket No. E002/GR-21-630.
	145. Xcel also agreed to continue working with the OES on forecasting issues. While Xcel maintains it cannot always meet a requirement to independently verify or duplicate all economic and demographic data obtained from third parties, it committed to working with the OES toward greater data transparency and will work closely with the OES to respond to any concerns regarding its data sources	
	146. ….[In] Docket No. E002/GR-05-1428, Xcel submitted its data used in test year sales forecasts 30 days before it filed this rate case. Company will comply with a similar requirement, if ordered in this rate case and will work with OES to facilitate it	

Order, 10/23/09; Order Point 13	147. Company will continue to maintain and monitor various resources such as the "Financial and Rate Revenue" report and "Tariff Analysis Report" discussed in the compliance report submitted on September 4, 2007 in Docket No. E002/GR-05-1428.	Requirement satisfied and provided in the forecast pre-filing materials submitted on October 1, 2020 in this docket.
	148. Company will continue working with OES on improving electronic linkage between CCOSS, forecasting and revenue models for its next rate case.	The Company is providing electronic copies of its CCOSS and revenue models via secure file transfer.
	In future rate case filings, Company shall include analysis of nuclear plant outage costs shown in OES Information Request 140, Attachment A, included in Exhibit 86.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 136-137 (Revenue Requirements).
		Vol. 4, Section III, Tab P4-1 Nuclear Outage Amortization.
09-1153	**2009 Gas Rate Case**	
Order, 12/6/10; Order Point 9	In all future rate case filings, Xcel shall disclose if the utility has elected a rate recovery method alternative to a Federal Accounting Standards Board pronouncement in reliance on Statement of Financial Accounting Standards No. 71.	Vol. 3, Section IV, Tab 3, Reg. Assets, Liabilities, Deferred Debits and Credits.
Order, 12/6/10; Page 37 (approving Pension Settlement, Exhibit 46)	The Company shall include a discussion of instances when it is relying on Statement of Financial Accounting Standards ("SFAS") 71, similar to its use of Aggregate Cost Method for pension accounting.	See Vol. 3, Section IV, Tab 3, Reg. Assets, Liabilities, Deferred Debits and Credits.
Order, 12/6/10; Page 37 (approving Pension Settlement, Exhibit 46)	NSP MN will continue to use the Aggregate Cost Method for ratemaking and financial purposes for pension expense. To the extent the Company is required to fund pursuant to the Pension Protection Act ("PPA"), the Company proposes that the treatment will be consistent with the Company's handling of SFAS 106.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, pgs 9, 20-25 and Schedules 4 & 5 (Pension).
GR-10-971	**2010 Electric Rate Case**	
Order 12/27/10	[A]t the hearing on this matter, the Company stated its agreement to file salary data for the 6th through 10th highest paid officers of the Company as public data.	Vol. 3 Section IV, Tab 2, Travel, Entertainment & Related Employee Expenses, EER Schedule 5.
AI-10-690 & GR-10-971	**Petition and Compliance Filing Cost Allocation Procedures and General Allocator and 2010 Electric Rate Case**	

Order, 3/15/11	In the course of the stakeholder discussions required under the October 2009 order, the Company and the OES agreed that the Company would begin rounding final allocators to the fourth decimal place – instead of the second, as it had in the past – and that it would not do any rounding of the numbers used in calculating those final numbers.	Ross L. Baumgarten Exhibit___(RLB-1), Vol. 2C, pg 16 (Cost Allocations).
Erratum Notice, 3/25/11	The Company shall change the formula for the general allocator and for all allocators in which it uses number of employees to substitute Allocated Labor Hours with Overtime in place of Number of Employees.	Ross L. Baumgarten Exhibit___(RLB-1), Vol. 2C, pgs 1-2, 15-22 and Schedule 4(a) (Cost Allocations).
GR-10-971	**2010 Electric Rate Case**	
ALJ Report, 2/22/12, Finding 555 and Exhibit 105	Tax Effect of Bonus Depreciation — Consumption of Deferred Tax Asset. The Company agreed to refund to customers the revenue requirements associated with the consumption of the deferred tax assets, estimated to return approximately $60 million over the period from 2012 through 2015. The Company agreed that the amount and timing of the consumption of the deferred tax assets will be trued up to actual results and subject to the Commission's approval, in the manner reflected in Exhibit 105, "Tax Normalization and Allowance for Net Operating Losses."	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 58-61, 103-04 and Schedules 10a-c, 11a-c, 12, and 20 (Revenue Requirements).
		Vol. 4, Section VIII, Tab A48 Net Operating Loss.
		NOL reports have been filed on May 31, 2012, May 31, 2013, June 2, 2014, May 29, 2015, May 31, 2016, May 31, 2017, May 31, 2018 , June 14, 2019, June 1, 2020 and May 27, 2021 in Docket No. E002/GR-10-971.
ALJ Report, 2/22/12, Finding 555 and Exhibit 105	Tax Effect of Bonus Depreciation -- Beginning with the 2011 MN jurisdictional annual report (filed May 1, 2012), reflect a deferred tax asset to be estimated to be $197 million at the end of 2011 based on the TY amounts provided in Mr. Robinson's Sch 4 and 5, which amount shall be trued up for actual results in the May 1 Report.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 58-61, 103-04 and Schedules 10a-c, 11a-c, 12, and 20 (Revenue Requirements).
		Vol. 4, Section VIII, Tab A48 Net Operating Loss.

		NOL reports have been filed on May 31, 2012, May 31, 2013, June 2, 2014, May 29, 2015, May 31, 2016, May 31, 2017, May 31, 2018 , June 14, 2019, June 1, 2020 and May 27, 2021 in Docket No. E002/GR-10-971.
ALJ Report, 2/22/12, Finding 555 and Exhibit 105	Tax Effect of Bonus Depreciation -- Establish a regulatory liability on the Company's books each year, beginning in 2012, for the revenue requirements associated with the consumption of the deferred tax asset that is projected to occur in that year, based on the budget data included in the jurisdictional annual reporting order to ensure that these amounts are reflected as being owed to customers as they are consumed.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 58-61, 103-04 and Schedules 10a-c, 11a-c, 12, and 20 (Revenue Requirements).
		Vol. 4, Section VIII, Tab A48 Net Operating Loss.
		NOL reports have been filed on May 31, 2012, May 31, 2013, June 2, 2014, May 29, 2015, May 31, 2016, May 31, 2017, May 31, 2018 , June 14, 2019, June 1, 2020 and May 27, 2021 in Docket No. E002/GR-10-971.
ALJ Report, 2/22/12, Finding 555 and Exhibit 105	Tax Effect of Bonus Depreciation -- The Company agrees to file on May 31 of each year, until such time that the deferred tax asset balance is fully reversed, a compliance report of the 1) deferred tax asset associated with the unused tax deductions and PTC carry forward balances; 2) the deferred tax liability associated with the year by year net change in bonus tax depreciation as provided by the Dec 2010 tax law change; and, 3) the revenue requirement effect of the actual utilization of the balances listed in 1 & 2 above. The compliance report shall be based upon the Company’s annual report filed with the Department of Commerce each May 1 and shall, if applicable, include a proposed refund plan to return to ratepayers the revenue requirement effect associated with the utilization of these deferred tax benefits. If there is not a refund required for any year, the Company must clearly explain why and explain any changes in the	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 58-61, 103-04 and Schedules 10a-c, 11a-c, 12, and 20 (Revenue Requirements).

	amounts estimated in Mr. Robinson's rebuttal pg. 17, Table 3.	
		Vol. 4, Section VIII, Tab A48 Net Operating Loss.
		NOL reports have been filed on May 31, 2012, May 31, 2013, June 2, 2014, May 29, 2015, May 31, 2016, May 31, 2017, May 31, 2018 , June 14, 2019, June 1, 2020 and May 27, 2021 in Docket No. E002/GR-10-971.
ALJ Report, 2/22/12, Finding 556 and Exhibit 56, Schedule 1	Employee Expenses: Provide direct testimony that includes an explanation of all employee expense data in the company's systems. NSP's direct testimony will explain the creation of our EER schedules. This will include an explanation of how we pulled the data from our employee expense reporting systems (primarily Concur or its successor system(s)) and an explanation of any data for which summary level information is provided, such a labor per diems, bargaining employee pay-in-lieu, safety, clothing allowances, etc. NSP's direct testimony will discuss any limitations of its EER schedules and provide a plan of action to correct the problems NSP identifies in both that proceeding and future proceedings.	William Kile Husen, Exhibit___(WKH-1), Vol. 2D, pgs 6-46 and Schedules 2-4, 7-8 (Employee Expenses).
ALJ Report, 2/22/12, Finding 556 and Exhibit 56, Schedule 1	Employee Expenses: Provide direct testimony that explicitly identifies certain types of employee expenses as "below the line" that NSP agrees to remove as representative of expenses we do not ask to recover from ratepayers.	William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 34-46 and Schedules 4, 8, and 10 (Employee Expenses).
ALJ Report, 2/22/12, Finding 556 and Exhibit 56, Schedule 1	These types of expenses include expenses where employees failed to properly document the business purpose of the expense as required by the company's policy. NSP will also remove expenses that, while perhaps helpful to employee morale, are not clearly necessary for the provision of utility service. The company may request inclusion of a certain level of non-safety recognition expense per employee as long as the company provides an explanation of how this level is maintained. This review will require subjective judgment. NSP will continue to request recovery of expenses such as safety awards and meals purchased for overtime work	William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 44-45 and Schedules 2, 3, and 8 (Employee Expenses).

	as required by union contracts. NSP's direct testimony will provide a clear road map for the OAG and other interested parties to be able to understand the types of expenses the company has removed. The direct testimony will also disclose whether...	
	NSP continues to request ratepayer recovery of any of the types of controversial expenses identified in this and our earlier rate case.	Vol. 3 Section IV, Tab 2, Travel, Entertainment & Related Employee Expenses.
ALJ Report, 2/22/12, Finding 556 and Exhibit 56, Schedule 1	Employee Expenses: Provide direct testimony that discusses overall budget levels for employee expenses and explains NSP's progress in improving employee expense reporting and compliance with the employee expense policy. This would also include a discussion of NSP's efforts to improve its performance on certain issues raised in this electric rate case such as providing a more complete business purpose and complying with NSP's spending limits for recognition and gift expenses. NSP's internal audit team will continue to review compliance with the company's expense policy regarding such things as:	William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 21-46 and Schedules 2, 3, 7, and 8 (Employee Expenses).
	1) providing a business purpose for incurring expenses;	
	2) limiting meal expenses to $65/day per person except in special circumstances approved by management; and	
	3) limiting business meals expenses to only instances where employees could not have been reasonably conducted their work during regular business hours.	
	NSP's direct testimony will include a summary of the findings of its internal audits. NSP will make the complete audit reports available to the OAG and the Department.	
ALJ Report, 2/22/12, Finding 556 and Exhibit 56, Schedule 1	Employee Expenses: Provide EER Schedules in a manner that facilitates easier review and quantification of categories, NSP will provide electronic versions of the EER Schedules to the OAG and the Department. This will allow parties, for example, to more easily identify the number of meal expenses over $65/per person.	Vol. 3 Section IV, Tab 2, Travel, Entertainment & Related Employee Expenses.

ALJ Report, 2/22/12, Finding 556 and Exhibit 56, Schedule 1	NSP commits to provide updates to the OAG and Department of changes NSP makes to its employee expense policies, employee expense reporting systems, or other changes that will affect NSP's future reporting under Minn. Stat. § 216B.16, subd. 17.	William Kile Husen, Exhibit___(WKH-1), Vol. 2D, Schedule 3 (Employee Expenses).
ALJ Report, 2/22/12, Finding 556 and Exhibit 56, Schedule 1	NSP commits to meeting with the OAG prior to the filing of future rate cases so the parties can discuss how to streamline regulatory review of employee expenses.	The Company met with the OAG on September 24, 2021.
ALJ Report, 2/22/12, Finding 557	The OAG requested that, in its next rate case, the Company include a report of the total compensation for employees engaged in lobbying, with an explanation of the costs included and excluded in the rate request. The Company has agreed to do so and the OAG requested that the Commission's order include this requirement.	William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 42-46, 64 and Schedule 10 (Employee Expenses).
GR-10-971	**2010 Electric Rate Case**	
Order, 5/14/12; Order Point 11	The Company shall establish a reporting and tracker mechanism for the deferred taxes generated by the bonus depreciation established at the time of this rate case filing. The Company shall make an annual filing detailing its utilization of the tax benefit until the tax benefit is fully realized.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 58-61, 103-04 and Schedule 20 (Revenue Requirements).
		Vol. 4, Section VIII, Tab A48 Net Operating Loss.
		NOL reports have been filed on May 31, 2012, May 31, 2013, June 2, 2014, May 29, 2015, May 31, 2016, May 31, 2017, May 31, 2018 , June 14, 2019, June 1, 2020 and May 27, 2021 in Docket No. E002/GR-10-971.
M-09-1048	**Modification to Xcel Energy TCR Tariff, 2010 Project Eligibility, TCR Rate Factors, Continuation of Deferred Accounting and 2009 True-up Report**	
Order 4/27/2010	In setting guidelines for evaluating project costs going forward, the TCR project cost recovered through the rider should be limited to the amounts of the initial estimates at the time the projects are approved as eligible projects, with	There were no costs of eligible projects excluded from TCR filings prior to the filing of this case.

	the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case.	
GR-12-961	**2012 Electric Rate Case**	
Order, 9/3/13; Order Points 10, 21	Nobles: 10. Xcel shall amortize the $5.6 million jurisdictional cost of the Nobles Wind Project, less the $500,000 already recovered, through depreciation over the remaining life of the plant (2013 to 2035). The unamortized balance will be excluded from rate base and a carrying charge is not allowed.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 83-84 and Schedules 11-12 (Revenue Requirements).
		Vol. 4, Section VIII, Tab A28 Nobles Amounts over CON.
Order, 9/3/13; Order Point 18	Sales Forecast: 18. Xcel shall include the following items in its next rate case:	While expressly limited to "its next rate case," i.e. the 13-868 docket, the Company has provided similar information in the current matter.
	a. Forecasting data at least 30 days prior to the initial rate case filing;	The Company Forecasting data was pre-filed on September 24, 2021.
	b. A comparison to the forecast information in this docket and the Baseload Diversification Study filed on or around July 1, 2013;	This request was specific to either the 2014 or 2016 TY forecasts and is outdated. In the Forecast pre-filing IR No. 18, we provided comparisons of the sales forecast to the GR-15-826 forecast, the RP-19-368 forecast, and the AA-19-293 forecast.
	c. Large industrial customer account data in a format that allows interested parties to readily access historical data for all customers;	Available upon request.
	d. A spreadsheet, with all links intact, identifying any data inconsistencies with the Company's raw weather data and any modifications made to the raw weather data;	Weather data was provided in Forecast pre-filing IR Nos. 12 and 13.
	e. A detailed step-by-step explanation as to how test year revenue was calculated and what commands should be changed if a party wishes to adjust test year sales, adjust customer counts or calculate revenue;	Order Points 18.e, 18.f and 18.g are addressed on Work Papers compact disc, file revmodMN2020TY.xlsx, "Overview" Tab.

Order, 9/3/13; Order Point 18	f. A detailed description of the changes the Company has made to simplify its test year revenue calculation so that persons outside of the Company may verify the accuracy of the calculation; and	Order Points 18.e, 18.f and 18.g are addressed on Work Papers compact disc, file revmodMN2020TY.xlsx, "Overview" Tab.
	g. A report on the meetings Company representatives have had, prior to filing, with interested parties to explain its revenue calculation process and to cooperatively discuss methods for streamlining the revenue calculation.	Order Points 18.e, 18.f and 18.g are addressed on Work Papers compact disc, file revmodMN2020TY.xlsx, "Overview" Tab.
Order, 9/3/13; Order Point 22	Allocation of CCRC in CCOSS: 22. Xcel shall allocate its Conservation Cost Recovery Charge using the per-kWh method as recommended by the Department.	Michael A. Peppin, Exhibit___(MAP-1), Vol. 2D, pgs 26-27, 47-48 and Schedule 13 (CCOSS).
Order, 9/3/13; Order Point 23	Allocation of Transmission in CCOSS: 23. Xcel shall reallocate transmission facility costs in this rate case in a manner consistent with its allocation of capacity costs, according to contribution to summer peak demand.	Michael A. Peppin, Exhibit___(MAP-1), Vol. 2D, pgs 2, 20-24 and Schedule 2, Appendix 2 pg 3. (CCOSS).
Order, 9/3/13; Order Point 29	AIP Refund Mechanism: 29. Xcel shall retain its existing refund mechanism, which provides customer refunds in the event that the incentive compensation payouts are lower than the test-year level approved in rates.	The Company proposes elimination of the AIP refund in this proceeding. Ruth K. Lowenthal, Exhibit___ (RKL), Vol. 2D pgs 2, 6, 37-44 (Employee Compensation).
Order, 9/3/13; Order Point 37	Compensating Return: 37. The Company shall not be permitted to include a compensating return on the pension's unamortized asset loss balances.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, pg 48-51 (Pension).
Order, 9/3/13; Order Point 40	Pension Schedules: 40. In future rate case filings, Xcel shall include for each pension plan schedules of its 2008 market loss amortization, for the entire amortization period, until the 2008 market loss amortization has been extinguished.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, page 18-19 and Schedule 3 (Pension).
Updated Issues List 6/5/13; Page 19	Wholesale Customer Reporting: The Company and Department also agreed the Company will provide as a compliance filing in future rate cases a wholesale customer study which shows all wholesale customers being served by the Company (including, but not limited to, full requirements, partial requirements and market based wholesale customers), types of service being provided to each wholesale customer, costs and revenues associated with each	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 131 and Schedule 14 (Revenue Requirements).

	wholesale customer and a clear showing either that wholesale costs are allocated out of the retail rate case or that the revenues are included in the retail rate case, for all services provided to wholesale customers.	
Updated Issues List 6/5/13; Page 26	Chemicals Reporting: The Department also recommended that the Commission require the Company to provide support in its initial case that is detailed and transparent for all proposed recovery of costs of chemicals (including mercury sorbent, lime, ammonia, etc.) including volumes and prices, reflecting historical data a competitively bid contract information and including the type of information provided in response to DOC information request no. 191.	Randy A. Capra, Exhibit___(RAC-1), Vol. 2B, pgs 95-113 and Schedules 5 and 6 (Energy Supply).
Heuer Direct pg. 20	Cancelled Projects. In future rate cases, the Company commits to identify cancelled or abandoned capital projects and related impacts on test year costs to the extent such cancellations are known at the time of filing its direct testimony.	Mark P. Moeller, Exhibit___(MPM-1), Vol. 2C, pg 14 (Depreciation).
Heuer Rebuttal pg. 21	Financial Labeling: All of the numbers in the rate case (initial filing and responses to information requests) should be clearly and consistently labeled in future rate cases, with focus on financial and not legal entities. The Company will make best efforts to label each amount as:	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 129-130, Schedule 5 (Revenue Requirements).
	Xcel Energy Services Inc. Definition: Service Company providing services across all Xcel Energy Inc. operating companies;	
	NSP System Definition: The integrated electric production and transmission system owned and operated by NSPM (in Minnesota, North Dakota, South Dakota) and Northern States Power Company-Wisconsin (in Wisconsin and Michigan) NSP-Minnesota; or	
	NSPM Definition: Total Company (electric and natural gas utilities)	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 129-130, Schedule 5 (Revenue Requirements).
	NSPM Electric Definition: Total Company (electric utility only)	
	State of Minnesota Electric Jurisdiction Definition: NSPM allocated to the electric utility	

	and Minnesota jurisdiction. Individual test year components and adjustments will be stated net of Interchange Agreement billings to NSPW.	
GR-13-868	**2013 Electric Rate Case**	
Order, 5/8/15; Page 67	For the Company's next rate case, the Commission encourages Xcel to work with MISO and other parties to recalculate the D10S Capacity Allocator on the basis of MISO's peak for purposes of comparison with Xcel's peak.	Michael A. Peppin, Exhibit___(MAP-1), Vol. 2D, pgs 2, 20-24 and Schedule 2, Appendix 2 pg 3. (CCOSS).
Order, 5/8/15; Page 69	The Commission will require Xcel to modify its 2014 and 2015 class-cost-of-service studies to use the location method to allocate other production O&M costs. Further, in its next rate case, the Company should continue using the location method to allocate these costs.	Michael A. Peppin, Exhibit___(MAP-1), Vol 2D, pgs 16, 27-29 (CCOSS).
Order, 5/8/15; Order Point 4	Monticello. 4. The disallowance of 2014 Monticello EPU depreciation expense shall be a permanent disallowance. The Company shall reduce Construction Work in Progress by this amount, or if the plant is shown as being included in Plant in Service, the disallowed depreciation expense will remain in the depreciation reserve. Xcel shall make a compliance filing within ten days of this order providing the accounting entries and explaining how this permanent disallowance is reflected in its accounting records.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 75 (Revenue Requirements).
		Vol. 4, Section VIII, Tab A13 Monticello LCM/EPU Return.
Order, 5/8/15; Order Point 7	Pension. 7. The Company shall apply the rolling five-year average FAS 87 discount rate when determining the XES Plan cost subject to deferral (or reversal) in subsequent years (i.e., non–rate-case test years) as the 2012 mitigation established in Docket No. E-002/GR-12-961 continues.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, pg 35-37 and Schedule 8 (Pension).
Order, 5/8/15; Order Point 10	Pension. 10. The qualified pension asset and associated deferred-tax amounts shall be included in rate base. For rate-base purposes, the pension asset is to reflect the cumulative difference between actual cash deposits made by the Company reduced by the recognized qualified pension cost determined under the ACM/FAS 87 methods since plan inception, not to exceed the Company's filed request.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, pg 61-68 and Schedule 13.

Order, 5/8/15; Order Point 13	Pension. 13. The discount rate used to calculate retiree medical benefit costs for ratemaking purposes shall be set to equal 5.08%, the five-year average of the FAS 106-based discount rates.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, pgs 52-56 (Pension).
Order, 5/8/15; Order Point 14	Pension. 14. Any amount by which the qualified pension expense allowed in rates exceeds future years' qualified pension expense (calculated using the Commission-approved discount-rate point of reference) the Company shall apply toward the recovery of the accumulated deferred XES Plan costs. "Future years" includes 2015, and each subsequent year's qualified pension expense if not a rate-case test year. The recoverable XES Plan expense amount shall be calculated using the proximate measurement date appropriate for each operating year (12/31/2013 for 2014; 12/31/2014 for 2015, etc.) until the next rate case. The Company shall file annual compliance reports which provide its pension plans' cost-calculation reports, the XES Plan accumulated deferred balance, and the excess rate-level recovery applied toward satisfying the deferral. Deferred amounts shall not be included in rate base.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, pg 50 and Schedule 11 (Pension).
		Compliance filings submitted on 6/14/17, 6/15/18, 6/17/19, 6/17/20 and 6/15/21.
Order, 5/8/15; Order Point 28	Aviation. 28. The Commission adopts ALJ Finding 564 modified to read as follows:	We are not seeking cost recovery of aviation costs in this case.
	The Commission orders the Company in future rate cases seeking recovery of corporate aviation to provide more detailed, accurate records of the actual business purpose for flights that are scheduled, rather than reducing all flights to a generic "code."	William Kile Husen, Exhibit___(WKH-1), Vol. 2C, pgs 9-10, 41 and Schedule 4 (Employee Expenses).
Order, 5/8/15; Order Point 29	AIP. 29. The Company has complied with the filing requirements set in its last rate case (Docket No. E-002/GR-12-961) regarding its Annual Incentive Compensation Program and shall continue to provide similar information and documents in any future rate case in which it seeks rate recovery of incentive-compensation costs.	Ruth K. Lowenthal, Exhibit___ (RKL), Vol. 2D pgs 20-36 and Schedule 4 (Employee Compensation).

Order, 8/31/15; Order Point 12	In future rate cases, the Company shall:	
	a. ensure internal consistency within its CCOSS and provide direct links to all inputs used in its model;	Nicholas P. Paluck ___Exhibit (NNP-1), Vol 2D, pgs 9-11, 34-36 and Schedule 8 (Rate Design). Michael A. Peppin, Exhibit___(MAP-1), Vol. 2D, pg 17 and Schedule 9 (CCOSS).
	b. include specific tabs within its CCOSS model that clearly identify all inputs (non-financial and financial) as well as all relationships between variables used in the cost model;	
	c. link input sources to the financial data and non-financial data filed in the record so that any changes made in compliance are clearly and promptly reflected in the relevant compliance cost study; and	
	d. provide estimated rate and bill impacts for customer classes to affirm the methodology of apportioning revenue responsibility.	
8/31/15 Order	In future multiyear rate cases, regarding the issue of the passage of time:	
Order Point 15	a. the Company must explicitly explain in Direct Testimony how the Company adjusts rates in years following the first year for the passage of time (all increased and decreased adjustments shown clearly); and	Greg P. Chamberlain , Exhibit___(GPC-1), Vol. 2A, pgs 36-37 (Policy/MYRP Policy).
	b. filings must contain clear calculations, including narrative, detailed calculations, well-labeled information, and support for how calculations tie out to the rate case revenue requirement requested by the Company.	Mark P. Moeller Exhibit___(MPM-1), Vol. 2D, pgs 25-28 and Schedules 2 and 5 (Depreciation).
M-15-401	**Courtenay Wind Cost Recovery**	
9/2/15 Order; Order Point 4	4. The Company shall include in the initial filing in its next rate case both testimony and schedules disclosing, in detail and by project, all North Dakota Investment Tax Credits and all other non-Minnesota state tax credits earned or held by the Company as a result of its investments and activity.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 138-139 Revenue Requirements).
GR-15-826		

GR-15-826, 6/12/17 Order Point 3	Xcel shall work with Commission and Department staff to develop a capital-projects true-up compliance reporting tool that meets the regulatory needs of the agencies, to be filed annually.	Compliance filing submitted 07/07/17 detailing agreed-upon reporting elements.
GR-15-826, 6/12/17 Order Point 5	Xcel shall make a compliance filing once the Mankato II in-service date becomes certain. If the in-service date does not materialize by 2019, the compliance filing should include the delay's 2019 revenue-requirement impact and how Xcel proposes to address it.	Compliance filing submitted 10/11/18.
GR-15-826, 6/12/17 Order Point 6	Within 90 days of the date of this order, Xcel shall make a compliance filing comparing final rate case expenses to the requested $3.34 million.	Compliance filing submitted 09/08/17.
GR-15-826, 6/12/17 Order Point 7	Xcel shall file, as a comparison, a true-up calculation based on actual (not weather normalized) sales and revenue throughout the term of the multiyear rate plan.	Sales True-up Compliance Filings were submitted on 2/6/17, 2/1/18, 2/1/19, 1/31/20 and 2/1/21.
GR-15-826, 6/12/17 Order Point 9; ALJ Findings 854, 855 & 856	Regarding the Class Cost-of-Service Study: b. Xcel shall report on methods to measure losses for Xcel's next rate case.	Kelly Bloch, Exhibit___(KAB-1), Vol 2B, pgs 192-195 (Distribution).
		Ian R. Benson, Exhibit___(IRB-1), Vol. 2B, pgs 117-120 (Transmission).
GR-15-826, 6/12/17 Order Point 9	Regarding the Class Cost-of-Service Study: e. For purposes of Xcel's next rate case, Xcel shall adopt the recommendations of the ALJ with the following exceptions: i. Xcel need not adopt the ALJ's recommendations regarding the classification and allocation of distribution costs. ii. Xcel shall base the D10S capacity allocator on Xcel's system peak coincident with MISO's system peak, incorporating any future changes to MISO's method for calculating the system peak.	Michael A. Peppin, Exhibit___(MAP-1), Vol. 2D, pgs 2, 20-24 and Schedule 2, Appendix 2 pg 3. (CCOSS).
GR-15-826, Order Point 11b	Company shall make filing every 6 months containing number of past-due residential customers and arrearage information and number of residential service disconnections.	Compliance Filings submitted on 07/31/17, 01/31/18; 07/31/18; 02/1/19, 07/31/19, 01/22/20, 07/30/20, 1/29/21 and 7/30/21. TBD: pointing to testimony to ask to sunset this

		/ note overlaps with other reporting.
GR-15-826, Order Point11c	Company shall actively reach out to past-due customers in order to inform them about the availability of assistance from LIHEAP. (Addressed in above-noted 10/10/17 compliance.)	Addressed in Compliance Filing submitted on 10/10/2017 regarding LIHEAP funding and outreach to low-income customers.
GR-15-826, Order Point Pg 47	For customers directly assigned substation costs and who do not receive service via other substations, exclude other substation costs in CCOSS	Michael A. Peppin, Exhibit___(MAP-1), Vol. 2D, pgs 25-26, and Schedule 2, Appendix 2 at 3 (CCOSS).
GR-15-826, Settlement, Page 6, Item D; Attachment 2 to the Settlement; ALJ Finding 183	Sales True-Up; the Company will true-up weather normalized actual sales for non-decoupled classes, subject to a three percent cap, in 2017, 2018 and 2019;	Sales True-up Compliance Filings were submitted on 2/6/17, 2/1/18, 2/1/19, 1/31/20, and 2/1/21.
GR-15-826, Settlement, Page 6, Item D; ALJ Finding 183	Decoupling .... for all decoupled classes, in 2017, 2018 and 2019, the decoupling mechanism approved by the Commission in the Company's last rate case will be extended to match the term of this agreement, which will address any differences between forecasted and actual sales.	Annual Decoupling reports were submitted on 2/1/17, 2/1/18 and 2/1/2019.
GR-15-826, Settlement, Page 7, Item F	PI LM Costs; The Settling Parties agree that a nuclear expert will be used in the Company's next Integrated Resource Plan ("IRP") proceeding, in which the Settling Parties expect to examine the continued cost-effectiveness of the Company's nuclear fleet, and evaluate the Company's forward looking (i.e., 2020-2030's) capital expenditures and O&M expenses, with the understanding that Xcel will continue to bear the burden of proof to show the reasonableness of rate changes in future proceedings.	This is a requirement of our Integrated Resource Plan.
		The Company's nuclear capital and O&M expenses are discussed by Peter A. Gardner, Exhibit___(PAG-1), Vol. 2B, 26-159 (Nuclear Operations).
GR-15-826, Settlement Page 9, III; ALJ Finding 465	Bill Payment Assistance for Customers with Medical Needs; Xcel Energy will develop and implement a customer bill payment assistance program exclusively for medical needs customers. The program will use the POWER ON program as a model and will incorporate the	Petition filed on 8/21/2017; Order approving program issued on 1/10/18.

	following: (1) providing an affordability credit in order to limit the percentage of household income that customers devote to electric costs; (2) providing an arrearage forgiveness component requiring customers to contribute a payment toward arrears (in addition to the affordability payment) in order to receive a matching monthly credit from the Company; (3) setting income eligibility for participation at 50 percent of the State Median Income ("SMI") and, only if funds remain, allow customers at 60 percent SMI to enroll; (4) providing assistance on a first come/first served basis until the program budget is exhausted; (5) limiting administrative costs to no more than five percent of the annual budget; (6) incorporating reporting and program fund tracking requirements of the current POWER ON program; and (7) recovering program costs on the same basis as the POWER ON program. The Company will file this proposed program within one hundred and fifty (150) calendar days of the Commission's final, appealable order in this proceeding.	
GR-15-826, Settlement Page 9, IV; ALJ Finding 103 & 104	LED Street Lighting; (1) The revenue requirements related to all capital additions for Light Emitting Diode ("LED") street lights will be removed from this rate case and the resulting changes to Xcel Energy's overall revenue requirements will be used in setting final street lighting rates ("LED Capital Cost Removal"). (2) All LED street lighting installed shall be billed consistent with the Commission's order in Docket No. M-15-920 and consistent with any final order in this rate case. (3) The revenue requirement reduction resulting from the LED Capital Cost Removal shall be reflected in final rates consistent with the rate design proposed by Xcel Energy or as otherwise may be ordered by the Commission.	Nicholas N. Paluck ___Exhibit (NNP-1), Vol 2D, pgs 35-37 and Schedule 9 (Rate Design).
GR-15-826, Settlement Page 9, IV; ALJ Finding 103 & 104	LED Street Lighting; (4) All street lighting costs proposed by Xcel Energy in this proceeding, other than the LED Capital Cost Removal costs, will remain and be reflected in retail rates as allowed by the Commission pursuant to its final order. (5) Xcel Energy will create a regulatory asset comprised of the revenue requirements directly related to any and all actual LED streetlight capital additions made of during the	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 91 and Schedules 10-12 (Revenue Requirements).

	Term of the MYRP as defined in the Settlement (the "LED Deferral"). Xcel Energy is explicitly permitted to defer the LED Deferral during the term of years for which final rates will be set in this rate case. Xcel Energy agrees that the LED Deferral will accrue no carrying cost or similar time value additive before its next rate case. (6) Any LED street lighting revenues collected during the Term of the MYRP shall be credited against the LED Deferral.	
		Nicholas N. Paluck __Exhibit (NNP-1), Vol 2D, pgs 35-37 and Schedule 9 (Rate Design).
GR-15-826, Settlement Page 10, IV	The LED Deferral shall be recognized and recovered as part of the test year of Xcel Energy's next rate case and such recovery shall be solely from the street lighting class;	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 91 (Revenue Requirements).
		Vol 4, Section VIII, Tab A38 LED Street lighting.
GR-15-826, Settlement Page 10-11, IV	Xcel Energy shall maintain reasonably detailed records of LED costs and cost savings compared to HPS lighting derived from a) relamping of LEDs, b) LED service orders, c) LED effect on base rate energy and d) demand allocation; and shall provide all relevant LED cost and cost savings information on street lighting in the next rate case.	Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 180-184 (Distribution).
		Nicholas N. Paluck ___Exhibit (NNP-1), Vol 2D, pgs 35-37 and Schedule 9 (Rate Design).
GR-15-826, Settlement Attachment 1	D. Implementation of Sales True-Up for 2017, 2018, and 2019; ...1. No later than February 15 of each year of the Term following the Commission's final order in this Proceeding, the Company shall make a compliance filing with the Commission ("True-Up Compliance Filing") providing: a. Actual sales data for the preceding year. b. Calculation of the true-up amount (either positive of negative) for the nondecoupled classes consistent with Attachment 2 of this Settlement ("Annual True-Up amount"), subject to a three percent cap on increases in rates for these customer classes. 2. The Settling Parties may file comments to True-Up Compliance Filing; provided, however, that such comments are consistent with the	Sales True-up Compliance Filings were submitted on 2/6/17, 2/1/18, 2/1/19, 1/31/20, and 2/1/21.

	agreement of the Settling Parties pursuant to this Settlement. 3. The Annual True-Up Amount shall be collected or refunded, as the case may be, over the 12 month period beginning April 1 of the year following the True-Up Compliance Filing (the "Amortization Year").	
GR-15-826; ALJ Findings 447 & 448; Burdick Surrebuttal Schedule 1	Capital True-Up; The Company will implement the capital true-up set forth in Company witness Mr. Burdick's Direct Testimony on pages 42-43 and on the timeline set forth on pages 49-50 and Schedule 15. Given the Settlement, the base line amount to be used for each of the four years will be the total annual capital related revenue requirements set forth in Department witness Mr. Lusti's second errata to Schedule DVL-9.	Capital True-Up Compliance Filings were submitted on 7/7/17, 5/1/18, 5/1/19, 5/1/20 and 4/30/21.
GR-15-826; ALJ Finding 261, 266 & 268; Burdick Surrebuttal Schedule 1	Property Tax True-Up; The Company will implement the property tax true-up set forth in Mr. Burdick's Direct Testimony on pages 44-45 and on the timeline set forth on pages 49-50 and Schedule 15. Given the Settlement and the property tax deferral in 2016, there will be no true-up in 2016 and the Company will use the property tax expense amount for 2016 established by Department witness Mr. Lusti in his Direct Testimony as the baseline for the property tax true-up for 2017, 2018 and 2019 property tax expense.	Property Tax True-Up Compliance Filings were submitted on 6/29/18, 7/1/19 and 7/1/20 in Docket E002/GR-15-826 and 7/1/21/ in Docket No. E002/M-19-688 on 7/1/21.
GR-15-826 Erratum Notice, July 28, 2017	Nuclear Refueling Outage Accounting; Xcel shall make a compliance filing showing the level of actual 2006–2015 nuclear-refueling-outage expenditures, by FERC account and by nuclear plant, and shall update the Commission on those expenditures annually by May 1. The filing must also show Xcel's 2006–2015 profit level resulting from the carrying charge.	Compliance filings were submitted on 5/1/18, 4/30/19, 4/29/20 and 4/30/21. The Company proposes to provide an additional filing by May 1, 2022 and will request to end this requirement after that filing. Peter A. Gardner Exhibit___(PAG-1), Vol 2X, pgs152 (Nuclear).
E,G002/D-17-147	**Xcel Energy's 2017 Annual Review of Remaining Lives**	
Order, 2/8/2018; Order Point 8	The Commission hereby approves the amortization rates as filed in Xcel's Attachment G to comply with the FERC accounting requirement that the Commission approve the amortizations rates for treatment of the FERC regulatory asset. In its next rate case and rider proceedings, Xcel must demonstrate that there	Mark P. Moeller Exhibit___(MPM-1), Vol. 2C, pgs 52-55 and Schedule 8 (Depreciation).

	are no cost impacts to Minnesota ratepayers due to Xcel's accounting treatment of its theoretical reserve amortization.	
AI-14-759	**Administrative Service Agreements with Xcel Energy Transmission Development Company and Xcel Energy Southwest Transmission**	
Order, 8/3/15, Order Point 2	Fully allocate costs and revenue credits for ASAs	Ross L. Baumgarten Exhibit___(RLB-1), Vol. 2C, pg 27-28 (Cost Allocations).
D-17-147	**2017 Annual Review of Remaining Lives**	
Order, 2/8/18, p. 6 and Order Point 8	In its next rate case and rider proceedings, Xcel must demonstrate that there are no cost impacts to Minnesota ratepayers due to Xcel's accounting treatment of its theoretical reserve amortization.	Mark P. Moeller Exhibit___(MPM-1), Vol. 2C, pgs 52-55 and Schedule 8 (Depreciation).
AI-17-577	**Affiliated Interest Filing**	
Order, 6/12/18, p. 7 and Order Points 2 and 3	Difference between Employee Ratio and Allocated Labor Hours with Overtime allocation methods will be adjusted for in future rate-recovery proceedings	Ross L. Baumgarten Exhibit___(RLB-1), Vol. 2C, pg 22 and Schedules 5(a) and 5(b) (Cost Allocations).
M-18-729	**Lighting Tariff Revisions**	
Order, 5/10/19	Company committed to revisit base rates for Street Lighting Energy Service tariff	Nicholas N. Paluck ___Exhibit (NNP-1), Vol 2D, pgs 35-37 and Schedule 9 (Rate Design).
M- 18-643	**Electric Vehicle Pilot Programs**	
Order, 7/17/19, Order Point 7	In its next rate case, Xcel must develop and propose a revised general service TOD rate that is more reflective of hourly system costs with a price signal designed to reduce peak demand.	This was proposed in E002/GR-20-723 and later filed separately in Docket No. E002/M-20-86 on 1/17/21.
Order, 7/17/19, Order Point 14	In its next general rate case filing, Xcel must address how it intends to handle and budget for future pilots	Greg P. Chamberlain , Exhibit___(GPC-1), Vol. 2A, pgs 46-47 (Policy/MYRP Policy).
		Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 169-179 (Distribution).
M-19-39	**Approval of Contracts and Ratemaking Treatment for Provision of Electric Service to Google's Data Center Project**	
Order, 7/15/19	C. Requires Xcel to provide in future rate cases when Xcel is including costs and revenues	Michael A. Peppin, Exhibit___(MAP-1), Vol. 2D, pg

	related to Google an update to both the overall Incremental Cost and Benefit Analysis and the Rate Case Incremental Cost and Benefit Analysis as recommended in the February 15, 2019 comments of the Minnesota Department of Commerce.	50 and Schedule 15 (CCOSS and Select Rate Design).
M-19-663	**In the Matter of a Petition for Approval of the Amended Agreement with Liberty Paper, Inc. and Approval of Accounting and Rate Treatment**	
Order, 2/21/20, Order Point 2	Requires Xcel to provide testimony in initial filings in rate proceedings outlining the services provided to LPI and demonstrating the reasonableness of Xcel's proposed cost allocations to the LPI steam sales	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 141-142 (Revenue Requirements).
		Ross L. Baumgarten Exhibit___(RLB-1), Vol. 2C, pgs 25-26 and Schedule 3 (Cost Allocations).
M-20-436	**Approval of Revisions to the Business Incentive and Sustainability (BIS) Rider Tariff**	
Order, 7/29/20, Order Point 1D	In its next general rate case, Xcel may seek recovery of the cost of the credits issued in this COVID-19 program. At that time, Xcel shall provide a cost/benefit analysis demonstrating the reasonableness of any cost recovery, including the full amount of the COVID-19 credits given and the sales revenue stimulated and retained. Xcel may defer the cost of these credits until its next general rate case.	The Company has not included recovery for this item in its request as it does not yet know the final amount of the discounts. If available, the Company may include this information in Rebuttal Testimony, or seek recovery in its next rate case. Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pg 89, 131-133 (Revenue Requirements).
Past Order Requirements provided as Supplemental Info		
GR-92-1185	**1992 General Rate Case**	
Order, 9/29/93	In its next general rate case filing, the Company shall be exempted from including the following items: comparisons of budgets to DRI guidelines; the budget documentation contained in Volumes 5, 6 and 7 of the current filing;	Budget Documentation is included in Vols. 5 and 6 of the Application. For contingency-related items, see Vol. 5, Capital Substitutions /

	translation reports linking cost element, cost activity and project budgeting mechanisms on a common and consistent basis to assure an audit trail; and month-by-month and year-end summary reports of contingency fund transactions and project substitutions. Separately but contemporaneously with its next general rate case filing, however, the Company shall file this information with the Commission, serve copies on the Department and the RUD-OAG and make this information available for review by other parties upon their request.	Contingent Process & Reports Tab.
GR-12-961	**2012 Electric Rate Case**	
Order, 9/3/13; Order Point 46	Discussion of Pension Plans. 46. In the initial filing of its next electric and gas rate case, Xcel shall include a discussion of each non-qualified retirement income plan (both defined benefit and defined contribution type plans) for which cost recovery is sought. The Company shall include in the filing and discussion disclosure of all characteristics of the unqualified plans that cause their unqualified status as well as the supporting documents and actuarial studies relied upon for the derivation of claimed cost.	Not applicable in this case. We are not seeking recovery of non-qualified pension in this case.
Order, 9/3/13	FERC Form 1 Details: 47. In the initial filing of its next rate case, the Company shall expand upon the information filed under Minnesota Rules 7825.4000(b) and 7825.4100(B), including balance sheet and income statement reconciliations between its FERC Form 1 and its general ledger accounts, for each of the three most recent calendar years relative to the rate case test year. The schedules provided shall be produced in like manner as requested and illustrated in the Department's Information Request 128-Revised, marked in the record as Exhibit 163, DOC Attachment ACB-15. The Company shall also include explanations of the accounts that have large differences in amounts when compared between actuals and its test-year request (change of ±10 percent or more).	Vol. 3, Section IV, Tab 5 GAAP/FERC/COSS Comparison.
Order Point 47		Vol. 6, Variance Explanations and Supplemental Reports Tab B.
GR-13-868	**2013 Electric Rate Case**	

Order, 5/8/15; Order Point 11	Pension. 11. In the initial filing of its next electric rate case, the Company shall; a. Address why the target asset allocations for its pension fund are reasonable, including ages of retirees and employees. The Company must provide an update to its existing Exhibit 31 (Tyson Rebuttal), Schedule 1 and expand it to include this demographic information.	R. Evan Inglis, Exhibit___(REI-1), Vol. 2D (Pension Investment).
	b. Provide testimony on its investment strategies and target asset allocations for the qualified pension fund and the justifications for those decisions, for the period from 2007 to the date of its next filing.	R. Evan Inglis, Exhibit___(REI-1), Vol. 2D (Pension Investment).
	c. Provide copies of the actuarial reports used to determine employee benefit costs, including its schedules denoting each subsidiary's cost assignments for each benefit. The Company must also include workpapers that show the derivation of the jurisdictional portion of each benefit cost.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, pgs 46, 55-62, 97 and Schedules 9 to 10 (Pension).
		Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 84-86 and Schedules 10a-c, 11a-c, and 12 (Revenue Requirements).
		Vol. 4, Section VIII, Tab A15 to A16, A29 to A32 Pension.
	d. Provide testimony that identifies and discusses each non-qualified employee-benefit cost included in its test years.	Not applicable in this case. We are not seeking recovery of non-qualified pension in this case.
	e. Include testimony identifying the basis used for its requested rate-base impact related to pensions. Additional schedules must be included that reflect the underlying calculation of the qualified pension asset (or liability) balances requested for rate-base inclusion.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 84-86 and Schedules 10a-c, 11a-c, and 12 (Revenue Requirements).
		Vol. 4, Section VIII, Tab A15 to A16, A29 to A32 Pension.
		Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, pgs 60-77 and Schedules 2 & 13 (Pension).

Order, 5/8/15; Order Point 37	CCOSS. 37. In its next rate case, Xcel shall refine its class-cost-of-service study cost-allocation method by identifying any and all other production O&M costs that vary directly with the amount of energy produced based on Xcel's analysis. If Xcel's analysis shows that such costs exist, then Xcel should classify these costs as energy-related and allocate them using appropriate energy allocators, while allocating the remainder of other production O&M costs on the basis of the production plant.	Michael A. Peppin, Exhibit___(MAP-1), Vol. 2D, pgs 27-29 (CCOSS).
Order, 5/8/15; Order Point 38	CCOSS. 38. In its next rate case the Company's class-cost-of-service study shall include an explanatory filing identifying and describing each allocation method used in the study and detailing the reasons for concluding that each allocation method is appropriate and superior to other allocation methods considered by the Company, whether those methods are based on the Manual of the National Association of Regulatory Utility Commissioners or the Company's specific system requirements, its experience, and its engineering and operating characteristics. The Company shall also explain its reasoning in cases in which it did not consider alternative methods of allocation or classification.	Michael A. Peppin, Exhibit___(MAP-1), Vol. 2D, Schedule 2, Appendices 2 and 3 (CCOSS).
Order, 5/8/15; Order Point 39	Minimum System Study. 39. In its next rate case, Xcel shall provide parties with data sufficient to verify and reproduce its minimum-system study and shall file a zero-intercept analysis of distribution costs, or explain why it was not able to collect the data necessary to do so.	Michael A. Peppin, Exhibit___(MAP-1), Vol. 2D, pgs 32-43 and Schedule 10 (CCOSS).
E-999, CI-03-802	**Investigation into Appropriateness of Continuing to Permit Electric Energy Cost Adjustments**	
Order, 11/5/2019 Order Point 2	In the initial filings for their next rate cases, each utility shall demonstrate that its proposed base rates exclude Fuel Clause Adjustment-related costs.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 119-120 and Schedule 21 (Revenue Requirements).
E-999/CI-15-115	**In the Matter of a Rate for Large Solar Photovoltaic Installations (E-002/M-13-315); In the Matter of a Commission Inquiry Into Standby Service Tariffs**	

Order 02/14/2020, Point 1(B)	Xcel shall update its PV Demand Credit Rider using the embedded generation and transmission costs established in future rate cases.	The PV Demand Credit Rider discount is updated through the Company's interim rate proposal. We will update compliance in final rates once the total revenue requirement is known.
E-002/M-17-797	**In the Matter of the Petition of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2017 and 2018, and Revised Adjustment Factor**	
Order 09/27/2019, Point 3	Xcel must use an ROE of 9.06% in all electric dockets that require an ROE determination until the Commission issues an order in the Company's next rate case authorizing a different ROE.	Vol. 1, Notice & Petition for Interim Rate.
Order 09/27/2019, Point 6	Xcel must include in any future cost recovery filing for ADMS investments an ADMS business case and a comprehensive assessment of qualitative and quantitative benefits to customers.	The Company will seek recovery of its AGIS investments in a future TCR Rider filing and does not include such investments in this case. AGIS-related internal O & M expenses are discussed at Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 137-140 (Distribution).
Order 09/27/2019, Point 9	If and when Xcel requests cost recovery for Advanced Grid Intelligence and Security investments, the filing must include a business case and comprehensive assessment of qualitative and quantitate benefits to customers, considering, at a minimum, the following [list of factors]	The Company will seek recovery of its AGIS investments in a future TCR Rider filing and does not include such investments in this case. AGIS-related internal O & M expenses are discussed at Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2B, pgs 137-140 (Distribution).
	When Xcel makes any future cost recovery proposal, in addition to requirements from previous orders, it must include: a. a discussion of mechanisms that will be employed to maximize cost reductions and minimize cost increases, and b. a demonstration that the utility has thoroughly considered the feasibility, costs, and benefits of alternatives, and that the proposed approach is preferable to alternatives.	The Company will seek recovery of its AGIS investments in a future TCR Rider filing and does not include such investments in this case. AGIS-related internal O & M expenses are discussed at Kelly A. Bloch,

	In discussing the alternatives, Xcel should compare different types of the same technology, for example, by comparing different AMI meters.”	Exhibit___(KAB-1), Vol. 2B, pgs 137-140 (Distribution).
E-002/M-17-828	**In the Matter of the Petition of Northern States Power Company for Approval of the 2019 – 2021 Triennial Nuclear Decommissioning Study and Assumptions**	
Order 03/13/2020, Point 2	Reduce the annual decommissioning accrual to $27.4 million, effective January 1, 2021.	Mark P. Moeller Exhibit___(MPM-1), Vol. 2C, pgs 62-63 (Depreciation).
Order 03/13/2020, Point 3	Increase the annual end-of-life nuclear fuel accrual to $2,087,026, effective January 1, 2021.	Mark P. Moeller Exhibit___(MPM-1), Vol. 2C, pgs 63-64 and Schedule 9 (Depreciation).
Order 03/13/2020, Point 4	Xcel may delay any increase from the current $14,030,831 until January 1, 2021.	Mark P. Moeller Exhibit___(MPM-1), Vol. 2C, pgs 62-64 (Depreciation).
E-002/M-19-39, E-002/M-19-60	**In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy for Approval of Contracts and Ratemaking Treatment for Provision of Electric Service to Google’s Data Center Project (E-002/M-19-39); In the Matter of the Petition by Northern States Power Company d/b/a Xcel Energy for Approval of Contracts and Ratemaking Treatment for Provision of Electric Service to Google’s Data Center Project (Highly Sensitive Trade Secret) (E-002/M-19-60)**	
Order 07/15/2019, Point 2(E)	E. Approves Xcel’s request that the costs associated with the Renewable Sourcing Plan be recoverable, now and in the future, through either –1) a future rate case or 2) the Fuel Clause Rider, with the protection that a net loss would require a review in the annual fuel clause review with a recovery determination made at that time.	There are no costs associated with the Renewable Sourcing Plan included in this base rate recovery request. The Company anticipates recovery through the Fuel Clause Rider, with review and recovery determination of an net loss to be determined in the appropriate fuel clause docket.
Order 07/15/2019, Points 3(A)-(D)	3. Regarding the Competitive Response Rider (CRR) Agreement, the Commission takes the following actions: A. Approves the CRR.B. Approves Xcel’s request to reflect the difference between the negotiated rate and the standard rate in the test year in a future rate case. C.	Michael A. Peppin, Exhibit___(MAP-1), Vol 2E, pg 50 and Schedule 15 (CCOSS).

	Requires Xcel to provide in future rate cases when Xcel is including costs and revenues related to Google an update to both the overall Incremental Cost and Benefit Analysis and the Rate Case Incremental Cost and Benefit Analysis as recommended in the February 15, 2019 comments of the Minnesota Department of Commerce. D. Requires Xcel to make a compliance filing showing that other ratepayers would not be harmed and that changes would not result in double recovery of costs.	
E,G-002/D-19-161	**In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of its 2019 Annual Review of Remaining Lives**	
Order 10/22/2019, Point 5	The Company shall return the net decrease in electric utility depreciation expense to ratepayers in the 2019 capital true-up filing in Docket No. E-002/GR-15-826.	The Company has complied with this requirement, and its most recent compliance filing in Docket No. E-002/GR-15-826 was on 05/01/2020.
03/12/2021 Order, Point 2	Xcel shall track investment spending for the acceleration of the projects separately from base rates, with clear delineation between portions that are included in base rates and those that are incremental to base rates.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 131-133 (Revenue Requirements).
E002/M-20-743	**In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of 2021 True-Up Mechanisms**	
04/2/21 Order, Point 12	The Commission accepts Xcel's commitment to not seek recovery of all pandemic-related costs, including bad debt costs, that are deferred and being tracked pursuant to the Order Approving Accounting Request and Taking Other Action Related to COVID-19 Pandemic and to withdraw its request for deferral in that docket	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 124-127 and Schedule 23 (Revenue Requirements).
06/14/2021 Order Denying Reconsideration, Point 3	Xcel must report improvements to its validation procedures and must hire, at its own expense, an independent auditor to review the Company's validation procedures and resulting revenue requirement deficiency in its next general rate case filing.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 124-127 and Schedule 23 (Revenue Requirements).
E,G002/M-19-723	**In the Matter of the Petition of Northern States Power Company for Approval of its 2020 Annual Review of Remaining Lives and Five-Year Depreciation Study**	

9/2/2021 Order Point 5	If Xcel seeks recovery of removal costs for the Luverne Wind2Battery in its next general rate case, Xcel must address the prudence of the estimated removal costs and ensure that such costs are not included in interim rates in that proceeding.	Benjamin C. Halama, Exhibit___(BCH-1), Vol. 2A, pgs 81-82, 114 and Schedules 10a-c, 11a-c, 12 (Revenue Requirements). Volume 4, Section VIII Adjustments, Tab A23, Electric Battery Reserve Reallocation

Key Compliance Filings for 2022-2024 MYRP

Compliance Filing	Date
2021 Actual Sales Data and Related Revenue Calculations for Sales True-up	2/01/2022
2021 Capital true-up Report	5/01/2022
2021 AIP, NOL Annual Compliance Reports	5/31/2022
2021 Property Tax True-up Report and Combined Refund Plan	7/01/2022
2022 2021 Actual Sales Data	2/01/2023
2022 Decoupling Report	4/01/2023
2022 Capital true-up Report	5/01/2023
2022 AIP, NOL Annual Compliance Reports	5/31/2023
2022 Property Tax True-up Report and Combined Refund Plan	7/01/2023
2023 Decoupling Report	4/01/2024
2023 Capital true-up Report	5/01/2024
2023 AIP, NOL Annual Compliance	5/31/2024
2023 Property Tax True-up Report and Combined Refund Plan	7/01/2024
2024 Decoupling Report	4/01/2025
2024 Capital true-up Report	5/01/2025
2024 AIP, NOL Annual Compliance Reports	5/31/2025
2024 Property Tax True-up Report and Combined Refund Plan	7/01/2025