Direct Testimony and Schedules
Aakash H. Chandarana

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-15-826
Exhibit___(AHC-1)

Policy and Multi-Year Rate Plan

November 2, 2015

Table of Contents

Schedules

I. INTRODUCTION

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

A. My name is Aakash H. Chandarana. I am the Regional Vice President for Rates and Regulatory Affairs for Northern States Power Company-Minnesota (NSPM or the Company). In this role, I am responsible for NSPM's 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. Prior to joining Xcel Energy, I was a partner at the law firm of Briggs and Morgan. My practice focused on the energy industry, primarily the state and federal regulation of utilities. I represented utilities in commercial transactions involving generation interconnection agreements, power purchase agreements and other types of related transactions. I also assisted my clients in regulatory proceedings, including the Minnesota certificate of need proceeding for the CapX2020 transmission lines, Xcel Energy's 2011 integrated resource plan, electric rate cases, and transmission interconnection disputes at the Federal Energy Regulatory Commission. In 2013, I joined Xcel Energy as its Lead Assistant General Counsel – Regulatory North. In that role, I was the lead regulatory attorney for our operations in Minnesota, North Dakota, South Dakota, Wisconsin and Michigan. In January 2015, I assumed my current role. Exhibit____ (AHC-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. In this case, we are requesting Commission approval of a multi-year rate plan (MYRP) for the period 2016-2018. While much of the information we provide in this application is the same as we have provided in previous traditional rate requests, we are presenting an important policy decision for the Commission in this case: whether it is in the public interest to implement a full multi-year rate plan (*i.e.*, one in which all capital and O&M are recovered for a period of time greater than one year) at this time. We believe it is. We believe a multi-year rate plan is a key tool that provides benefits for our customers, policy makers, regulators, other stakeholders, and the Company as we move into the future.

We recognize this is a significant policy decision for the Commission. To support our request and inform the Commission's decision in this matter, my testimony outlines how the Company plans to respond to the needs of our customers and policy makers over the next five-years, and discusses in some detail the changing industry landscape that is driving changes in our business. We believe it is important for the Commission and stakeholders to understand our plans and the strategies and considerations behind those plans. We believe understanding our rate request from this perspective confirms that an MYRP is the right ratemaking construct going forward. In my testimony, I:

- Explain the Company's plans to meet our customers' and stakeholder needs for the next five-years;
- Discuss the evolving business landscape in which we are operating;
- Outline the Company's multi-year rate proposal; and
- Present the structure of our case and introduce Company witnesses.

Q. PLEASE SUMMARIZE THE COMPANY'S RATE REQUEST.

A. We propose a three-year rate plan requesting an average retail rate increase of 6.4 percent in 2016, 8.1 percent in 2017 and 9.8 percent in 2018 when compared to present rates. We base this increase on a revenue deficiency of approximately $194.6 million in the 2016 test year, a revenue deficiency of approximately $246.7 in 2017, and a revenue deficiency of approximately $297.1 in 2018. The revenue deficiencies are based on a 10.00 percent return on equity.

Q. WHAT RATE INCREASE CAN CUSTOMERS EXPECT TO SEE WHILE THIS CASE IS ON-GOING?

A. Our revenue request results in a proposed interim rate increase of approximately 5.5 percent beginning January 1, 2016. Due to the expected length of this proceeding, and based on lessons learned from our recent rate case, we are also proposing an additional interim rate increase of 1.5 percent beginning January 1, 2017. Our requested interim rate request for the first and second year of this multi-year rate plan is consistent with the MYRP statute, as amended this year.

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

A. Yes, the Company's interim rate request for 2016 is approximately two percent lower than it would be because we are proposing to keep two significant transmission projects in the Transmission Cost Recovery (TCR) Rider. The Company explains this proposal, including the roll-in of these projects into base rates, in my Direct Testimony, Company witness Ms. Anne E. Heuer's Direct Testimony, and the Interim Rate Application.

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

A. The Company recognizes that in response to customer demands and state and federal policy initiatives, the business environment for utilities is changing. With that, utilities and our regulators need to be open to change too. Collectively, we need to become more innovative, think more competitively, and be more responsive to the evolving needs of customers and other constituencies. The Company cannot accomplish this alone. Partnerships with our regulators, stakeholders, and customers are critical to navigating the changing landscape. Together, I believe, we can accomplish significant State policy-related goals that benefit our customers over the long-run while maintaining Minnesota's leadership in progressive energy policy.

We believe a multi-year rate plan is a key element that supports changes that allow us to collectively be successful in the evolving energy industry landscape. While some changes in our industry present challenges and require that we adapt, other changes, such as technology advancements, provide the opportunity to make some significant progress – in cleaner energy, more resilient systems, and expanded options for our customers. In my testimony, I outline the Company's business plan and goals, discuss the changes in our industry that are informing our decision, and explain the need for an adequate runway to execute our plans, which we believe only a multi-year rate plan affords.

I then discuss our three-year rate plan proposal. I outline the key aspects of our request, including the drivers for our proposed rate increase, and explain the ways in which our request complies with Minnesota Statute Section

216B.16, subd. 19 (the MYRP Statute) and results in just and reasonable rates. As part of this discussion, I also identify the areas where our request conforms to the new language of the MYRP Statute and, by doing so, takes a different approach than outlined in the Commission's Order addressing criteria and standards for multi-year rate plans in Docket No. E,G 999/M-12-587 and discuss the policy reasons supporting this departure.

Q. HAS THE COMPANY INCLUDED AN ALTERNATIVE TO ITS THREE-YEAR RATE REQUEST?

A. Yes. While the Company noticed a three-year rate plan, my testimony details an alternative five-year rate plan offer. I believe the five-year rate plan offered by the Company can provide greater value and benefits for our customers and all other interests. A five-year plan can provide the predictability and certainty our customers have asked for. At the same time, our five-year plan will allow us to continue providing safe and reliable electric service, creating greater time and space to accomplish important policy objectives, such as providing cleaner and greener energy and greater customer choice in services and products, and assuring affordable energy prices to preserve Minnesota's competitiveness. We decided to include this alternative at the outset in response to lessons learned from our last rate case. By doing so the Company and interested parties can further develop the record on this alternative.

Q. HAS THE COMPANY ADDRESSED THE IMPACT OF ITS RECENT RATE INCREASES ON ITS CUSTOMERS?

A. Yes. We are aware of the impact of recent rate increases on our customers, especially the impact of these increases on our low-income customers. In recent years, the Company has supported increasing the amount of funding for existing low income programs. With this case, the Company is advancing a new program to aid seniors and those with chronic or severe medical conditions who currently do not receive Company, state or federal energy assistance support. Company witness Mr. Michael C. Gersack addresses our proposal in his Direct Testimony.

Q. DO YOU HAVE ANY OTHER INTRODUCTORY REMARKS?

A. Yes. In the Company's recent electric rate cases, we explained that significant capital investments, which were put into motion prior to the recession that began in 2008, drove our need for rate relief. In our last case, we described that the Company was crossing the peak of its current capital investment cycle. As we demonstrate in this case, we have crossed that peak over the last two years and our current forecasts indicate our investments will level off over the next five-year period.

Q. IF THE COMPANY HAS CROSSED ITS INVESTMENT CYCLE PEAK, WHY IS A RATE CASE NEEDED AT THIS TIME?

A. Crossing our investment peak does not mean we can stop investing in our system that delivers the safe, reliable, and reasonably priced electric service our customers rely on every day. Utilities are inherently infrastructure intensive; we cannot allow assets that are necessary to serve customers to deteriorate to the point that safety, reliability or customer choice also deteriorate. While our current forecasts indicate that our base rate needs level off during the next five-years, we have a sizeable revenue deficiency in the first year of our three-year rate plan and we need to keep investing in our core business in an environment with flat sales. Much of the test year deficiency (approximately half) is driven by certain capital that was not requested or not fully recovered in our last rate case and by the impact of the rate mitigation tools that were used in that case. As a result, we have a need for rate relief at this time.

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

A. Yes. The underlying philosophy we took with structuring our rate request was to avoid litigating issues that have been previously resolved by the Commission in a consistent manner or that were specifically addressed by the Commission in our last rate case. Examples of this include proposing substantially the same rate design that was just approved, and applying the same treatment for corporate aviation, our annual incentive plan, our restoration plan, and nuclear retention program as approved by the Commission in that case. Also consistent with our last case, we propose true-ups for sales forecast and property taxes to further narrow issues. We believe this approach will allow parties to avoid re-litigating issues and instead focus on analyzing this case constructively.

Additionally, our approach to this case is informed by the fact that we were able to work with parties to narrow the number of contested issues that came before the Commission. We believe we can build on the constructive give and take that took place in the last case by trying to settle this case during the contested case process and, in doing so, deliver customer benefits. The parties and Commission have a variety of tools to settle such cases, including the use of the Office of Administrative Hearings (as set forth in the Statute), and the use of more formal mediation or arbitration type procedures. An example of an approach would be for parties to engage in formal mediation after intervening parties have an opportunity to file their direct testimony. To the extent the Commission agrees, and finds a settled outcome to be of interest, we ask the Commission to encourage parties to explore settlement, even through mediation.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In my testimony, I:

- Discuss how the Company plans to meet customer and stakeholder needs for the next five-years;
- Discuss the evolving industry landscape in which all of us are operating, which provides challenges, but at the same time opportunities for significant advancements;
- Present our multi-year rate plan, highlighting the aspects that provide benefits to our customers, other stakeholders and the Company as we move into the future; and
- Present the structure of case and introduce the Company's witnesses.

In addition, Exhibit____(AHC-1), Schedule 2 provides a comprehensive completeness matrix identifying those areas of our Application that address the completeness requirements from prior Commission orders.

II. RESPONDING TO CUSTOMER NEEDS AND STATE AND FEDERAL POLICY

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

A. In this section of my testimony, I provide background information about the Company, describe the primary business strategies and decisions that informed the Company's actions over the last several years, and explain our plan to meet our customers' and other stakeholders' needs and expectations going forward.

Q. PLEASE FIRST DESCRIBE NSPM.

A. NSPM serves more than 1.4 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 over 8,300 MW, more than 7,300 miles of transmission lines, and approximately 550 transmission and distribution substations.

The NSP System includes approximately 2,500 megawatts (MW) of renewable energy capacity, including wind, hydro, biomass, and solar resources. Of this total amount, over 1,800 MW has been added over the past seven years and we anticipate adding at least an additional 4,930 MW over the upcoming 15 years, with 1,420 of those MW coming into service over the three year term of our requested MYRP.

Q. IN THE LAST RATE CASE THE COMPANY STATED THAT IT WAS CROSSING THE PEAK OF A SIGNIFICANT CAPITAL INVESTMENT CYCLE. WHAT WAS THE FOCUS OF THE COMPANY'S CAPITAL EXPENDITURES DURING THAT CYCLE?

A. For at least the last five-years, we have focused on investing in carbon free generation – specifically our nuclear generating units and new wind generation resources – and the transmission system needed to deliver this generation to load. These investments were in addition to the capital investments we always need to make in our distribution, transmission, and generation assets to help ensure we can safely and reliably serve our customers.

Q. WHY DID THE COMPANY FOCUS ON THESE TYPES OF INVESTMENTS?

A. The State of Minnesota and the federal government have set forth environmental and policy goals that we are obligated to meet. We are also obligated to meet North American Electricity Reliability Corporation (NERC) system reliability standards, and we take seriously our obligations to provide quality customer service and a safe working and operating environment. These needs exist at all times.

Q. WHAT IS NEXT?

A. In some ways, our future looks similar. Although we have taken several steps forward to meet the needs described above, we still need to focus on capital investments that address the health of our distribution, transmission, generation, and information technology assets. However, our customers and policy makers are also driving important differences for the Company's overall approach. First, our focus is evolving to include reducing carbon emissions in addition to investing in carbon-free generation, consistent with energy policies that govern our business. Second, we are also looking at investments that will enhance our customer's experience, as customers demand. Taken together, continued investment in our system to maintain reliability, reducing carbon emissions and investing in replacement generation, and investing to enhance our customers' experience provide broad benefits to our customers and help move forward Minnesota's progressive energy policy goals.

Q. WHAT ARE THE GOALS OF THE COMPANY'S BUSINESS PLAN?

A. The goals of our plan are straightforward based on these principles:

- Continue to reduce carbon emissions at an affordable price;
- Meet our customer's expectations by providing a more diversified experience and better ways of communicating;
- Continue to maintain and improve our excellent reliability;
- Provide a safe work environment that sends each and every employee home injury-free; and
- Keep energy prices affordable and competitive.

Q. CAN YOU ELABORATE ON THE COMPANY'S GOAL TO AFFORDABLY REDUCE CARBON EMISSIONS?

A. Yes. On October 2, 2015, the Company submitted its reply comments in its 2015 Integrated Resource Plan proceeding. Our comments outlined a path for transitioning our generation fleet to be cleaner and greener. This plan goes beyond solely investing in new renewables and our nuclear fleet and affirmatively reduces carbon emissions. We believe we can deliver this plan affordably due in part to low interest rates and natural gas prices.

Q. CAN YOU ELABORATE ON THE COMPANY'S GOAL TO MEET CUSTOMER EXPECTATIONS?

A. Yes. We understand that the majority of our customers continue to want the same things they have always wanted – reliable, affordable electric service. With that said, there is a growing segment of our customers whose expectations are changing. We want to be the trusted energy provider of all our customers. To that end, we plan to offer our customers a variety of new products and services. For example, on October 15, 2015, we brought forward a voluntary LED street lighting plan (Docket E002/M-15-920), which provides our customers the option to transition to safer, brighter street lights while saving on average two to four percent per month. On October 30, 2015, we filed our first biennial distribution plan that provides a framework for our grid modernization efforts (Docket No. E999/M-15-439). By mid-November, we will also bring forward a pilot program, which will offer to all our customers the opportunity to be served by a blend of wind and solar resources. As I explain later, the Company is proposing a performance metric to further the goal of bringing more innovative solutions to our customers.

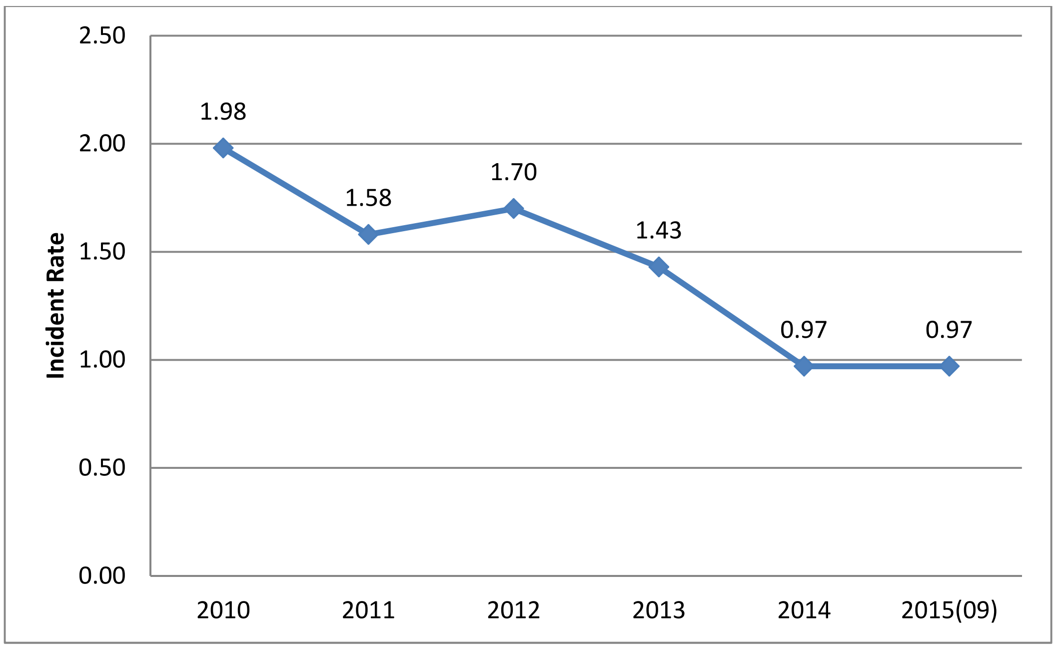
Q. IS THERE ANYTHING YOU WOULD LIKE TO ADD ABOUT THE RELIABILITY AND AFFORDABILITY GOALS?

A. Yes, reliability and affordability are at the heart of our business. In fact, we must be reliable to be the trusted energy provider to our customers. To that end, the Company must continually invest in our core and supporting assets. I note our excellent reliability performance provides us the platform that allows us to move to more innovative goals, such as aggressively reducing carbon dioxide emissions and proactively expanding the services and products we offer our customers.

Q. IS THERE ANYTHING YOU WOULD LIKE TO ADD ABOUT THE COMPANY'S SAFETY GOALS?

A. Yes, safety is a core value at Xcel Energy. We are committed to providing a safe work environment and sending each and every employee home injury-free. We are now in the fifth year of our company-wide Journey to Zero initiative, which has the goal of achieving zero injuries. It is built on the philosophy that safety is a vital part of our daily work, and perhaps more importantly, that we are personally accountable for our own safety as well as the safety of our co-workers. Our business plan continues this commitment to safety as a core value and as demonstrated by Figure 1, our efforts in this area have been successful.

Figure 1
NSPM Safety Performance
OSHA Recordable Incident Rate



Q. WHAT IS THE BENEFIT OF THIS BUSINESS PLAN?

A. For our customers, this plan helps assure safe, reliable, clean and affordable electric service while at the same time opening new options. For regulators and policy makers, this plan continues to build on our collective achievements continues to position Minnesota at the forefront of energy policy. For the Company, our plan charts a path certain for the near future, while maintaining our flexibility to adapt to emerging circumstances. Stated concisely, our plan is intended to position all stakeholders well for the near term and long term changes expected in the utility industry.

III. THE CHANGING INDUSTRY LANDSCAPE

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

A. In this section of my testimony, I explain the changes that are occurring in the industry, and the value of our multi-year rate plan in this context.

Q. WHAT IS DRIVING THE INDUSTRY LANDSCAPE TO CHANGE?

A. There are several factors that I will highlight:

- The inability of load growth to provide the funds necessary to meet these challenges;
- The need to invest, by replacing aging infrastructure and doing so in a way that meets these customer needs and protects against physical and cyber-based threats;
- Emerging environmental, reliability-focused, and federal market driven policy changes; and
- Changing customer expectations, including expectations of new services, new choices, greater efficiency in their own energy use and cleaner power.

Q. WHAT IS HAPPENING WITH SALES AND USE PER CUSTOMER ON AN INDUSTRY WIDE BASIS?

A. Generally speaking there is downward pressure on sales and use per customer. Over the last few years, there has been an emergence of greater energy efficiency technologies which are reducing electricity demand growth and changing 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 electricity. This combination is causing lower sales volumes and falling revenues, which is a new experience for utilities.

Q. HOW DO THESE INDUSTRY TRENDS COMPARE TO THE COMPANY'S EXPERIENCE?

A. Our experience in NSPM has followed these industry trends since the Great Recession. For the five-years prior to the Great Recession, the Company experienced sales growth of 1.4 percent on an annual basis, and use per customer increased 0.5 percent on annual basis. As Figures 2 and 3 illustrate our sales declined and then flattened and our use per customer has steadily declined since that time.

Figure 2

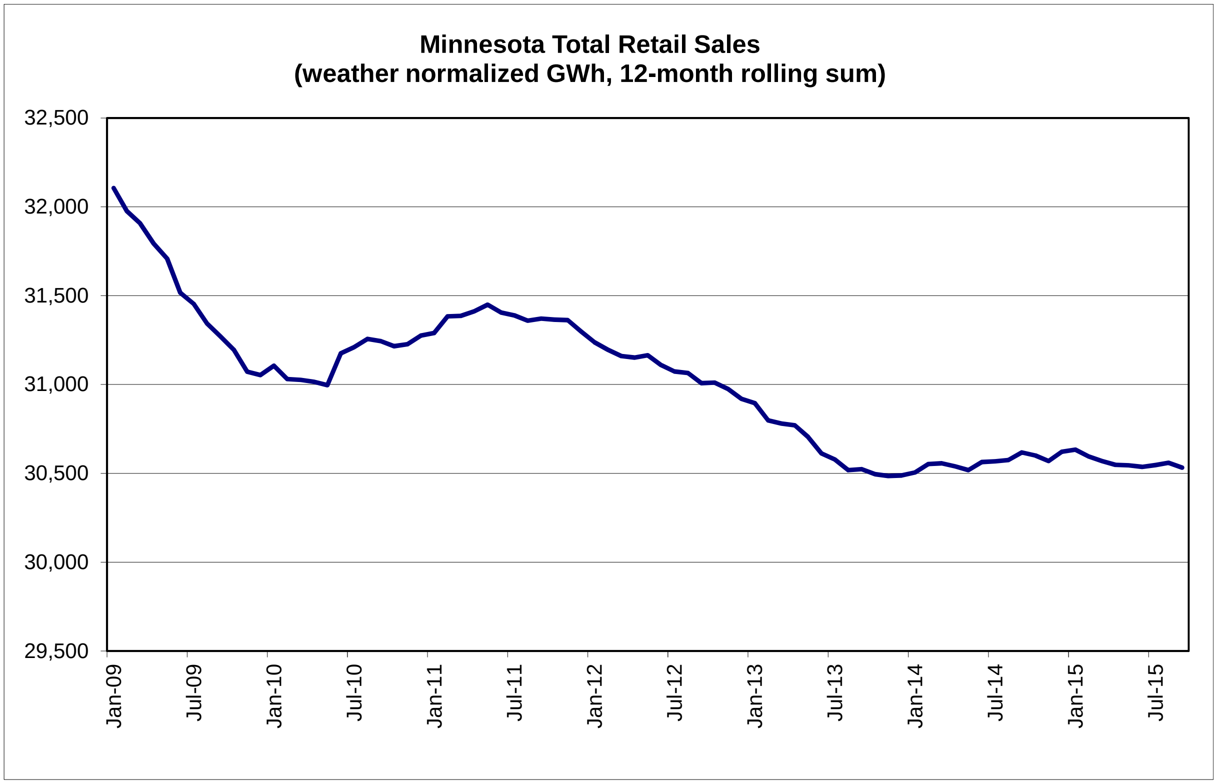
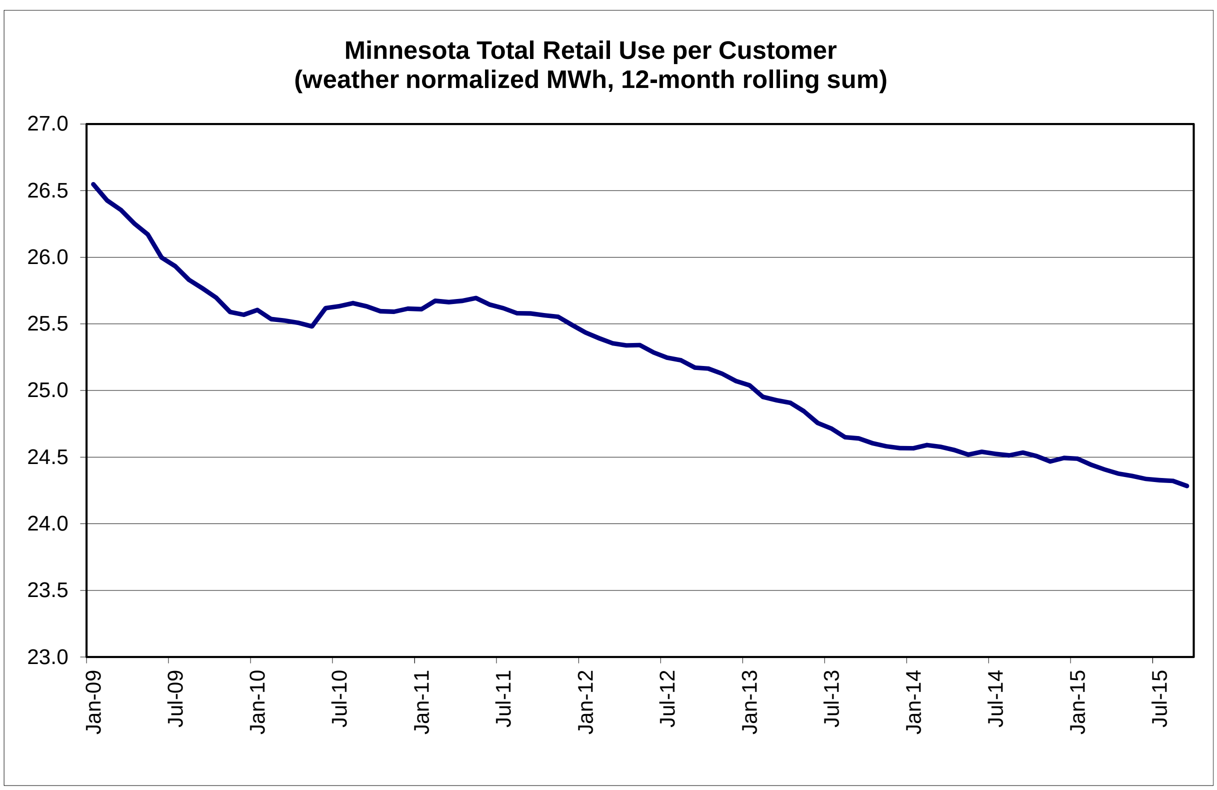


Figure 3



Q. WHAT IS CAUSING THE LACK OF SALES GROWTH AND DECLINE IN USE PER CUSTOMER?

A. There are a number of factors that contribute to lack of sales growth and declining use per customer. While Company witness Ms. Jannell E. Marks discusses this in detail in her Direct Testimony, I will note one example. Last year, the Company experienced an increase in the number of customers due to new construction. However, use per customer declined, due to improved energy efficiency technologies being used in those new buildings. The net impact was that the Company served more customers, but saw flat overall sales levels. While this outcome is consistent with State policy objectives, we believe it is important to recognize declining use per customer flattens sales growth even when we are adding customers and that this trend will continue as more and more energy efficiency technologies are emerging.

Q. WHY IS THE COMPANY CONTINUING TO INVEST IN A DECLINING SALES ENVIRONMENT?

A. The short-term and long-term benefit of our customers demands it. Even as conservation improves and sales growth slows, as a Company we must and we will make investments in the infrastructure to continue serving our customers safely and reliably.

Q. THE NEXT FACTOR YOU IDENTIFIED IS AGING INFRASTRUCTURE. HOW IS AGING INFRASTRUCTURE IMPACTING THE UTILITY INDUSTRY?

A. The utility industry as a whole has an aging baseload fleet. Based on the Company's analysis of the information regarding the nation's generation fleet, large, baseload coal and nuclear fleets nationwide are nearing the end of their useful life, with the nation's large coal fleet averaging an age of 37 years and the nation's nuclear fleet averaging an age of 34 years. This represents about a quarter of the nation's thermal generation. The same is true regionally, with about a third of the Midcontinent Independent System Operator's (MISO) large, baseload, thermal generation reaching the same aging thresholds.

As the nation's generation fleet ages, utilities are faced with a need to invest in either lengthening the lives of the existing fleet or retiring aging units and investing in replacement capacity and energy. We are seeing the beginning of a responsive investment cycle with almost a quarter million megawatts of combined cycle capacity being installed in the last 15 years. The aging fleet, in light of environmental and market drivers I discuss below, places the industry at a crossroads.

Not only generation assets need refreshing. Significant investments in transmission facilities to accommodate new renewable generation and to meet reliability standards are also necessary. On a regional level, MISO's last several Transmission Expansion Planning cycles have identified the scope and scale of that build-out. Additionally, as technology becomes more sophisticated and cyber security becomes a paramount concern within the industry, ensuring that supporting information technology is up to date is becoming a focus nationwide.

The American Society of Civil Engineers, in their 2013 Energy Infrastructure report card, summed up the impact of the aging infrastructure on the nation's energy grid as follows:

> Looking ahead in the 21st century, our nation is increasingly adopting technologies that will automate our electric grid and help manage congestion points. In turn, this will require robust

> integration of transmission and distribution systems so that the network continues to be reliable.
>
> Investments in the grid, select pipeline systems, and new technologies have helped alleviate congestion problems in recent years, but capacity and an aging system will be issues in the long term. In addition, with an automated, dynamic energy grid system comes the increased risk of cybersecurity threats. Protecting the nation's energy delivery systems from cyber attacks and ensuring that these systems can recover is vital to national security and economic well-being.

Q. IS THE COMPANY'S EXPERIENCE SIMILAR?

A. Yes, on several fronts. First, the Company's generation fleet is also aging. As we described in our 2016 Integrated Resource Plan, almost all of the Company's generation sources will turnover in the next twenty years. Figure 4 illustrates this.

Figure 4
Potential Generation Retirements

Year	Baseload	Intermediate - Natural Gas CC	Peaking - Natural Gas CT
2016			
2017			
2018			
2019			Flambeau (13 MW)
2020	Manitoba Hydro (75 MW)		
2021			
2022			
2023	Sherco 2 (694 MW)		
2024	Bayfront (Biomass) (67 MW)		Blue Lake 1-4 (157 MW)
	French Island (Biomass) (16 MW)		French Island (CT) (122 MW)
			Granite City (54 MW)
2025	Manitoba Hydro (500 MW)		
	Manitoba Hydro (350 MW)		
		Invenergy (358 MW)	
2026	Sherco 1 (709 MW)	Calpine Mankato (357 MW)	Wheaton (298 MW)
2027			Inver Hills (287 MW)
2028	Red Wing (Biomass) (21 MW)	LSG Cottage Grove (262 MW)	
	Wilmarth (Biomass) (19 MW)		
2029			
2030			
2031	Monticello (671 MW)		Angus Anson 2&3 (186 MW)
2032		Black Dog 52 CC (285 MW)	
2033			
2034	Prairie Island 1 (548 MW)		
2035	Prairie Island 2 (548 MW)		Anson 4 (149 MW)
			Blue Lake 7&8
2036			
2037			
2038	AS King (541 MW)		

Additionally, as Company witnesses Mr. Ian R. Benson and Ms. Kelly A. Bloch discuss, our transmission and distribution infrastructure is aging and requires continual investments in asset health to remain reliable. Additionally, as Company witness Mr. David C. Harkness describes, our supporting infrastructure also needs to be refreshed and upgraded to ensure that our infrastructure has the appropriate technological support as we look toward the future.

Q. WHAT DOES THIS MEAN FOR CUSTOMERS AND THE COMPANY?

A. With the age of our fleet, our customers and policy makers have a voice in shaping the generation assets that will serve them for the next 40 years. For us, we appreciate that we need to be responsive to this feedback but at the same time we need to continue safely, reliably serving all customers at an affordable price.

Q. THE NEXT FACTOR YOU IDENTIFIED IS CHANGING CUSTOMER EXPECTATIONS. WHAT IS HAPPENING AT AN INDUSTRY LEVEL?

A. Customer expectations are evolving rapidly in all areas involving utility service and products. The following are becoming important considerations for our customers:

- Emerging technologies – rapidly evolving technology such as home energy management, battery storage, and solar are drawing customer interest.
- Clean energy – customer interest in renewable energy continues to grow as prices decline.
- Improved communications – as other service provider oriented industries present enhanced customer service experiences, consumers expect improved virtual services and tools from utilities.
- Increased ability to control their energy use – customers want the ability to make decisions about their energy service and be able to easily compare services and products.

Customer sentiments towards energy are changing and utilities must evolve to meet these expectations. Customer feedback has informed us that after reliability, residential customers continue to want more control over their electricity use and want to improve their ability to manage their electricity consumption. We are receiving similar feedback from our commercial and industrial customers who want more control and optionality to meet sustainability goals with better and simpler products.

Q. WHAT IS THE COMPANY'S EXPERIENCE WITH CHANGING CUSTOMER EXPECTATIONS?

A. Customer interest is highest in the following products and services:

- Outage notification
- Online energy management tools
- Time-of-use rates
- Smart meter installations
- Backup power
- Battery storage
- Rooftop solar incentives
- Online chat (customer service)

Q. HOW IS THE COMPANY RESPONDING?

A. We continue to evaluate and expand our products and services to meet growing customer expectations. For example, to provide our customers with the ability to be served by renewable generation, which will present an opportunity for our customers to meet their sustainability goals while using our service, we will be introducing a pilot program soon that will allow for the direct streaming of wind and solar energy to subscribing customers. In addition, we recently submitted a request for Commission approval of a voluntary LED street lighting program. This program brings brighter and more efficient lighting technologies to our customers. The Company is also regularly updating and improving our digital tools such as My Account, website transaction tools and outage communications. For example, we launched a customer communication pilot in June 2015 to 50,000 residential electric/natural gas customers. With this pilot, we notify customers of high or unusual energy use mid-bill-cycle so they can take action if necessary.

To complement our efforts to provide more products and services, the Company is researching several new technologies, such as energy storage, and alternative rates to give customers more options to manage their energy use and bills. At the same time, we are forging partnerships with the communities we serve to apply our research and further it as well. For example, the Clean Energy Partnership between the City of Minneapolis, CenterPoint Energy, and the Company allows us to work together with a key community in our service area to help achieve their carbon reduction goals and overall energy vision.

Q. THE LAST FACTOR IS ABOUT CHANGING ENVIRONMENTAL AND RELIABILITY POLICIES. LET'S TAKE THEM ONE AT A TIME. WHAT IS LEADING TO THESE CHANGES AND WHAT SPECIFIC ENVIRONMENTAL POLICIES ARE IMPACTING THE INDUSTRY?

A. Customers demand cleaner energy sources and state and federal environmental policies, along with the market, are responding to that demand. The most significant federal environmental regulations impacting our generation fleet are the United States Environmental Protection Agency's

(EPA) Clean Power Plan, national ambient air quality standards, regional haze, coal ash, and water-related rules. Each of these is summarized in detail in the Company's Upper Midwest Resource Plan filing.[1]

Q. HOW ARE THE CHANGES TO ENVIRONMENTAL POLICIES YOU JUST DESCRIBED IMPACTING THE COMPANY?

A. Given this broad suite of federal and state environmental mandates, continuing to transition our generation fleet away from coal toward natural gas and renewables will provide flexibility and minimize emerging regulatory risks to our customers. While coal remains an important part of our baseload generation portfolio, our focus is on avoiding significant new investments in our coal fleet, continuing to operate our carbon-free nuclear units, and investing aggressively in wind, solar and natural gas generation. We appreciate 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 are demanding.

Q. HOW ARE RELIABILITY BASED POLICY CHANGES IMPACTING THE INDUSTRY?

A. In 2007, the Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce reliability standards on all transmission owners. This authority is derived from amendments to the Federal Power Act through which Congress gave FERC the authority to enforce reliability issues throughout the industry in response to a massive outage in Ohio and the region.

[1] Docket No. E002/RP-15-21. See in particular Appendix D to our January 2, 2015 filing, and our October 2, 2015 Reply Comments.

There are now over 100 mandatory reliability standards and over 1,000 sub-requirements that NERC is actively engaged in assessing penalties, both monetary and non-monetary, for noncompliance. In addition, NERC is constantly assessing existing standards and implementing new standards.

The NERC standards, and more specifically the heightened enforcement of them, have created a singular focus on reliability industry-wide. Utilities are continuously studying the bulk transmission system, and distribution system, to better understand changing demand patterns, generation portfolios, and infrastructure. From there, utilities are driving proactive investment throughout the industry resulting in a more robust electric system.

Q. HOW ARE THESE EMERGING NERC STANDARDS IMPACTING THE COMPANY?

A. When NERC standards are modified or new standards are introduced, the Company must develop the infrastructure, processes, and documentation to ensure compliance. For example, the new Physical Security requirements, which became effective in May 2014, require new assessments of the transmission system to assess physical vulnerabilities and two levels of independent verifications. The revised and new standards will improve the reliability of the bulk electric system but require extensive resources to develop, implement, and document. Stated simply, NERC compliance requires us to continue investing in our infrastructure in order to ensure that we provide reliable service to our customers.

Q. WHAT DO YOU MEAN BY FEDERAL MARKET DRIVEN POLICIES?

A. Federal policy initiated through FERC has generally been to find market based solutions to address the wholesale generation and delivery of energy and capacity by creating systems intended to send price signals to address generation and transmission needs. The most recent illustration of this policy approach is seen with FERC Order No. 1000. With Order No. 1000, FERC further refined its open access and transmission planning policies by broadening regional planning requirements and introducing market concepts to transmission development through required competitive bidding for regional transmission projects.

Q. HOW ARE FEDERAL MARKET DRIVEN POLICIES CHANGING THE UTILITY INDUSTRY?

A. Federal market driven policies have had a significant impact on the utility industry as a whole. In total, they are creating market structures to drive competition. This may have long term implications on system planning and development of generation and transmission solutions to meet reliability needs.

Importantly, the impact of FERC's imposition of market based dynamics is continually implicating the federal/state jurisdictional divide in utility regulation. In fact, two key issues related to FERC's jurisdiction with respect to demand response and organized capacity markets are being heard by the United States Supreme Court this term. As FERC continues to move policies based on pricing signals, the impact to state authority is a key issue as wholesale structures are developed.

Q. HOW ARE THESE POLICIES GOING TO IMPACT THE COMPANY?

A. FERC's imposition of market-type dynamics on utilities will require us to keep evolving wholesale structures in mind as we look toward the future. Creating our Transco is but one response to this landscape. As the line between state and federal jurisdiction continues to evolve, we must be thoughtful about the investments we make.

IV. THE VALUE OF A MULTI-YEAR RATE PLAN

Q. How is your prior discussion related to the Company's rate request?

A. As the industry changes, ratemaking should change with it. We believe that our proposed three-year MYRP is the right ratemaking construct in this environment.

Q. Has ratemaking changed over the years?

A. Yes, there have been several changes to ratemaking since traditional cost of service ratemaking was developed in the late 19th century. For example, several states, including Minnesota, began using future test years and allowing interim rates to address the regulatory lag inherent with cost of service ratemaking in the mid- to later part of the 20th century. At that time, interest rates and inflation were very high. As a result historic test years without interim rates resulted in final rates that did not reflect the utility's cost of service and the filing of another rate case shortly thereafter.

Q. Why do you believe that cost of service ratemaking should be adjusted?

A. At the outset, it is important to note that we are not saying cost of service ratemaking should be immediately replaced with something else. Our MYRP proposal has been built on full cost of service principles as I will discuss below. However, cost of service ratemaking does need to evolve so that we can "manage forward," rather than continuing to manage in the present and past.

Several reasons lead us to the conclusion that cost of service ratemaking should be adjusted. First, annual rate cases have become more the norm. This may present greater stress as we continue investing to meet the demands of our aging system and to meet our customers' evolving needs. More rate case filings will drain resources, and make it challenging to have important policy discussions with our regulators.

Second, as rate cases become more complex and take longer to process, the future test year is becoming more real-time, if not, historic. Our last rate case provides an example of this as we will implement final rates approximately two years after filing. This kind of regulatory lag, coupled with needed investments and flat sales growth, makes it challenging for final rates to reflect a utility's cost of service much past the year the rate case is decided.

Third, there has been a recent transition away from evaluating the test year as a representative picture of our capital investments to a bill of sale (*i.e.*, an expectation that we will make the investments exactly as they are laid out in our budgets). While this type of project-by-project expectation is appropriate for riders where few projects are evaluated, it is straining the cost of service ratemaking model for base rate cases, where several hundreds, if not thousands, of projects are included in budgets as representative of the work we intend on doing. We need a certain degree of flexibility to run our business and respond to our customers' needs.

Q. WHY IS A MYRP A BETTER NEXT STEP FOR RATEMAKING IN MINNESOTA THAN FILING FOR MORE FREQUENT RATE INCREASES?

A. The Company appreciates that filing for a rate increase on an annual or every other year basis is a model that can work in certain regulatory environments. As discussed by Company witness Mr. Charles E. Burdick in Direct Testimony, Wisconsin has used this approach for many years. With that being said, and in conjunction with the challenges I previously described with annual rate cases and Mr. Burdick describes with the approach used in Wisconsin, the Company believes a MYRP provides the rate certainty to implement our business plan in a way that benefits customers. Mr. Burdick identifies several states that have adopted a MYRP construct as the next step in evolving cost of service ratemaking.

Q. DOES A MYRP PROVIDE FOR SUFFICIENT REGULATION AND OVERSIGHT OF THE COMPANY?

A. Yes, a MYRP provides regulators and stakeholders with a seat at the business-planning table, which provides for a different but more in-depth and engaged type of regulation and oversight than today. For example, if customer affordability is the most important goal for the State, regulators can set rates and the utility will adjust its business accordingly. The same can be said for advancing carbon free generation, carbon emission reduction or expanding the services available to our customers. We do not believe line-item reviews facilitate these kinds of discussions and for that reason a MYRP offers a very different kind of regulation and oversight.

We note the Commission also always has the ability to monitor the impacts of a MYRP on all stakeholders and to judge whether the utility continues to meet key goals and is earning a reasonable, but not excessive, return.

Q. HOW CAN RATEPAYERS AND OTHER STAKEHOLDERS BENEFIT FROM THIS APPROACH?

A. A multi-year rate plan can:

- *Provide predictability and moderation of the pace of rate increases.* An MYRP provides customers with predictable rate increases during the plan period while providing the utility a strong incentive to manage its business within the level of revenues provided. The value of establishing a revenue limit requires context. Our Company always has a list of prudent projects longer than our ability to finance or our customers' desires to pay for. The single test year approach of focusing exclusively on the reasonableness and prudence of proposed projects does not consider other factors, such as affordability, which can be considered in a MYRP.
- *Provide a longer-term view of costs and investments for customers, regulators and stakeholders.* A MYRP allows customers and regulators a longer-term view of a utility's investment and management plans, and therefore encourages a discussion about the utility's investment plans. We believe this is of value when significant investments are on the short-term or long-term horizon, such as is the case with our aging generation fleet. By comparison, a single test year model sets rates for only the test year.

Conceptually the focus is on representative expenditures and costs which limit insight into investment cycles that span several years.

- *Facilitate investments that support state energy policy goals.* A MYRP encourages investments consistent with the priorities of regulators, policy makers, and customers. When a utility outlines an investment plan consistent with the expectations of regulators, policy makers and customers, the utility should receive stable and predictable rate recovery and earn its authorized return so that it can execute the plan.
- *Preserve the basic regulatory bargain between utilities, regulators and customers.* A MYRP still allows for a full review of the reasonableness of the utility's proposed rates and can provide customer protections.

Q. HAVE ANY OTHER STATES USED THIS APPROACH WITH SUCCESS?

A. Yes. Mr. Burdick discusses the experience 20 other states have had with implementing three-year or longer multi-year rate plans, and identifies other states that have approved two-year rate cases with ratemaking elements similar to longer-term, multi-year plans.

Q. DOES XCEL ENERGY OPERATE IN ANY OF THE STATES WHERE MULTI-YEAR RATE COMPACTS HAVE BEEN APPROVED?

A. Yes. Xcel Energy has experience with MYRPs in Wisconsin, South Dakota, North Dakota, and Colorado. We developed our MYRP plan and proposal after reviewing how other states have utilized MYRPs and based on our experience in other jurisdictions.

Q. WHAT IS THE RELEVANCE OF OTHER STATES' EXPERIENCE AND XCEL ENERGY'S EXPERIENCE TO MULTI-YEAR RATE PLANS IN MINNESOTA?

A. We believe the cumulative experience demonstrates that multi-year rate plans can be important tools for aligning the interests of customers, policy makers and utilities. Stated more simply, multi-year rate plans can help deliver the types of experiences our customers and policy makers want by providing greater rate certainty and predictability.

Additionally, multi-year rate plans across the country have similar elements. For example, longer rate compacts typically include a way to objectively increase rates on an annual basis, a mechanism to annually adjust components of cost of capital, and customer protections to assure the utility does not over-earn. There also can be a requirement that prohibits the utility from filing a rate case when the multi-year rate plan is in effect and that requires the utility to file rate cases on a set schedule. The recently amended MYRP Statute provides for the same ingredients; the experience of other states merely demonstrates that these ingredients can be used together successfully.

Q. CAN YOU PROVIDE AN EXAMPLE OF A MULTI-YEAR RATE PLAN USED IN ANOTHER STATE?

A. Yes. In Washington State, the Washington Utilities and Transportation Commission (UTC) used a MYRP framework for Puget Sound Energy (PSE) to address a persistent rate case cycle and motivate the utility to be more cost-sensitive. The UTC was explicit in their policy goals:

> The Commission in this Order implements several innovative ratemaking mechanisms that, together, fulfill the Commission's policy goal of breaking the recent pattern of almost continuous rate cases for Puget Sound Energy, Inc. (PSE). As the Commission observed in PSE's 2011/2012 general rate case (GRC): "This pattern of one general rate case filing following quickly after the resolution of another is overtaxing the resources of all participants and is wearying to the ratepayers who are confronted with increase after

> increase. This situation does not well serve the public interest and we encourage the development of thoughtful solutions."[2]

Q. WHAT ARE THE KEY ELEMENTS OF THE MYRP APPROVED BY THE UTC?

A. The plan approved by the UTC has the following key features:

- Annual rate increases based on 3 percent escalation factors;
- Annual escalation factor represents a weighted average based on the percentage of non-production related revenue requirements;
- Rate base and depreciation expense components of the escalation factors are based on the historical compound growth rate in these costs;
- Operating expenses based on forecasted average Consumer Price Index, less a one-half percent productivity factor;
- Annual escalation factors set below what PSE's analysis shows it needs in order to motivate efficiency and cost-cutting, but reasonably represent cost increases expected over the plan term ("stretch goal"); and
- Fixed escalation factors applied to each year's allowed revenue per customer for purposes of the decoupling mechanism.

As stated in the Washington UTC's Order, these factors worked together to hold "the promise of customers paying rates that are lower than might be the case under traditional approaches to ratemaking. The rate plan is designed to give an incentive to PSE to become more efficient and to implement cost-cutting measures that will promote its ability to earn its authorized overall rate of return. The rate plan includes important protections for customers,

[2] Order 07, Final Order Granting Petition and Final Order Authorizing Rates, Dockets UE-121697 and UE-130137

including an earnings test that requires PSE to share with customers on an equal basis any earnings that exceed its authorized return during the term of the plan."[3]

Q. IS THERE ANOTHER EXAMPLE YOU WOULD LIKE TO PROVIDE?

A. Yes. In Colorado, NSPM's sister subsidiary, Public Service Company of Colorado (PSCo), entered into their second three year rate plan in 2015 which incorporated costs associated with implementation of Colorado's Clean Air Clean Jobs Act. The Clean Air Clean Jobs Act was enacted in spring of 2010 and required regulated utilities, such as Xcel Energy, to work to reduce emissions from coal-fueled power plants. This multi-year rate plan also provided the utility with rate certainty, and the ability to earn its authorized return, during a period of time when significant capital investments are being made (approximately $1 billion capital expenditures). By including an earnings-sharing mechanism, two goals are achieved: (1) Colorado customers are protected from a situation in which PSCo over-earned; and (2) the utility is further incentivized to manage and even reduce its expenditures due to the sharing portion of the mechanism.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THESE EXAMPLES?

A. All in all, these are good examples of multi-year rate plans playing an important role in achieving the outcomes desired by customers and policy makers in a manner which is fair for the utility and its investors. At the same time, these examples illustrate ways to keep affordability in mind and to protect against concerns that the utility is over-earning or will not provide the

[3] *Id.*

level of reliable service its customers continue to expect.

V. 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 2016 (2016 Test Year) and plan years of calendar years 2017 and 2018 (2017 Plan Year and 2018 Plan Year, respectively).

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

A. The Company is requesting rate increases of $194.6 million in 2016, $52.4 million in 2017 and $50.7 million in 2018. Ms. Heuer and Mr. Burdick provide the revenue requirement schedules supporting this request.

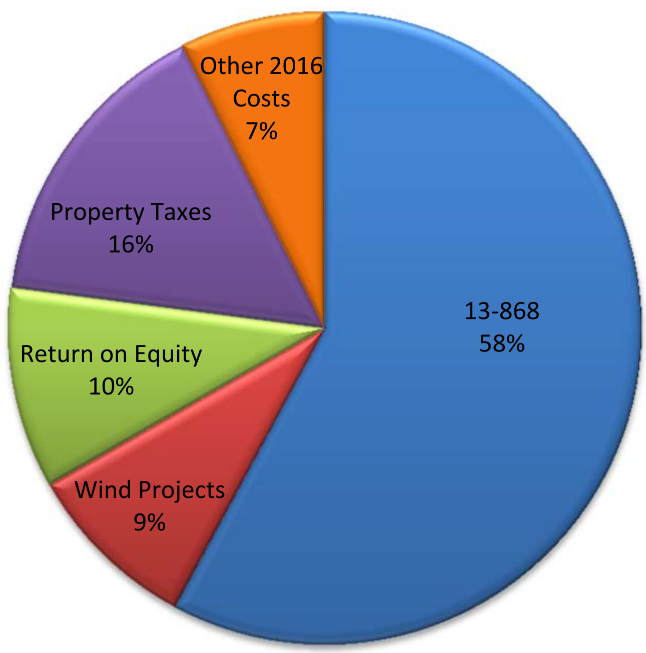
Q. CAN YOU SUMMARIZE THE TEST YEAR FINANCIAL DRIVERS?

A. Yes. While the test year reflects ongoing investments and increased costs, it is important to recognize that a significant portion of our 2016 request relates to items carried forward from our last rate case. Specifically, the "bounce back" effect of the rate moderation mechanisms used in our prior case ($51.8 million of the 2016 revenue deficiency), the inclusion of 2015 capital projects that were not included in our "step" request in our prior case ($49.6 million of the 2016 revenue deficiency), the full recovery of the Monticello LCM/EPU ($11.2 million of the 2016 revenue deficiency), and the annualized recovery of Borders and Pleasant Valley project costs ($17.3 million of the 2016 revenue deficiency). Thus, these four items alone account for nearly 60 percent of our

2016 revenue deficiency and represent the single largest "driver" of our rate increase request for 2016.

Ms. Heuer discusses the key drivers behind the 2016 revenue deficiency and, collectively, they are represented in Figure 5 below.

Figure 5
2016 Revenue Deficiency Drivers



Q. PRIOR TO DEFINING "BOUNCE BACK" IS THERE ANYTHING YOU WOULD LIKE TO NOTE ABOUT THE 2016 DEFICIENCY?

A. Yes. I note that our 2016 request is in line with our previous projections regarding our revenue needs in 2016. As Company witness Mr. Christopher B. Clark stated in his Rebuttal Testimony in our last rate case, the Company estimated revenue deficiencies averaging approximately $150 million per year for the three-year period ending with 2016.

Q. WHAT DO YOU MEAN BY "BOUNCE BACK"?

A. In the last rate case the Company proposed and the Commission approved the use of two rate moderation tools: (1) accelerated amortization of transmission, distribution and general-plant depreciation theoretical reserve, and (2) refunding Department of Energy settlement payments for the storage of spent nuclear fuel that were in excess of the amounts needed for decommissioning. As the Company explained in our last electric rate case, both tools provided benefits to our customers in 2014 and 2015, and the accelerated amortization of theoretical reserve even provides benefits in 2016. However, as we also explained in our last electric rate case, our 2016 and 2017 revenue requirement are higher from using these moderation tools in 2014-2016.

Q. HOW ARE THE 2015 CAPITAL PROJECTS THAT WERE NOT INCLUDED IN THE 2015 STEP DRIVING THE COMPANY'S CURRENT REVENUE DEFICIENCY?

A. In our last electric rate case the Company did not request recovery of all of its capital investments planned for 2015. We filed our case in this manner based on our interpretation of the Commission's MYRP Order, and the then-current MYRP Statute. At the time we filed our last rate case, we believed the MYRP Order to confine multi-year rate plans in a number of ways, including limiting the second and third year requests to recovering "specific, clearly identified capital projects and, to the extent appropriate, related non-capital costs." Given this limitation, the Company structured its rate request with a 2015 "step year" that included specifically identified capital projects, but did not include all of the Company's reasonable and necessary capital investments. Our 2016 revenue requirement now reflects the fact that the Company made these investments, even though it did not receive a rate increase supporting them.

Q. HOW IS THE MONTICELLO LCM/EPU PROGRAM IN-SERVICE DATE IMPACTING THE COMPANY'S CURRENT REVENUE DEFICIENCY?

A. In the last rate case the Commission decided that the Company could place the Monticello Life Cycle Management/Extended Power Uprate (LCM/EPU) program in-service after final regulatory approvals were received from the Nuclear Regulatory Commission. The Company received those approvals in July 2015 and placed the program in service at that time. Due to the beginning of year/end of year rate base averaging convention used by the Company and the timing of placing the plant in service last year, the 2016 deficiency fully reflects this program being placed into-service. Ms. Heuer explains this further in her testimony.

Q. HOW ARE THE PLEASANT VALLEY AND BORDERS WIND PROJECTS IMPACTING THE COMPANY'S CURRENT REVENUE DEFICIENCY?

A. Both of these projects will be placed into service near the end of 2015. Due to the beginning of year/end of year rate base averaging convention used by the Company and the timing of placing the plant in service in 2015, the 2016 deficiency fully reflects these projects being placed into-service. Ms. Heuer explains this further in her testimony.

Q. SO IS THE COMPANY NOW SEEKING RECOVERY OF MONEY IT WAS ALREADY DENIED?

A. No. The financial impact of the "bounce back" issues were understood at the time and are the expected results of adopting rate moderation proposals in the last rate case proceeding. The impact of now including the capital that was not included in the 2015 "step" was similarly understood by the limitations set forth in the MYRP Order. We note it is also similar to any situation where rate base grows faster than depreciation expense between rate cases. In regards to the Monticello LCM/EPU, Pleasant Valley and Borders, we have followed the Commission's order in our last case and are following our standard accounting practices. We are not now asking for recovery that was denied; on these items we are simply "catching up," based on decisions made in the last rate case.

Q. BEYOND THE DRIVERS RELATED TO THE LAST RATE CASE, WHAT ARE THE KEY FINANCIAL DRIVERS OF THE TEST YEAR DEFICIENCY?

A. While Ms. Heuer presents a detailed discussion of the 2016 revenue deficiency drivers, the other significant drivers include:

- *Ongoing investments in carbon free electrical generation.* These include investments and expenses related to our nuclear plants and in wind energy. Company witnesses Mr. Timothy J. O'Conner and Mr. Steve H. Mills 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. Mills, Mr. Benson and Ms. Bloch all discuss our need to address certain aging infrastructure and to do so in a way that not only ensures safe, reliable and clean energy for our customers, but does so in a manner that meets customer's and policymakers needs and expectations going forward.
- *Investments in our information technology systems.* We have a need for increased investment in our information technology infrastructure and

assets to meet our compliance *obligations*, as well as to address the security, data, and technology needs of the organization and our customers. Mr. Harkness provides details on the investments in this area.

- *Increased costs of business.* We continue to experience increased costs across our business. *Some* of those costs relate in part to investments, such as property tax increases. Others are for providing the compensation and benefits needed to attract and retain the employees that provide our customers with safe and reliable service.

Q. DO THE 2017 AND 2018 PLAN YEARS HAVE THE SAME REVENUE DEFICIENCY DRIVERS AS THE 2016 TEST YEAR?

A. Yes, the 2017 and 2018 revenue deficiencies are heavily driven by capital investments in carbon free energy, replacing aging transmission and distribution infrastructure, and addressing our information technology needs. Mr. Burdick provides a schedule showing the drivers for these years, and each applicable business unit witness specifically addresses the needs and drivers as well.

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

A. No. Due to the fact that our last rate case just concluded and was thoroughly evaluated, and the existence of an on-going separate rate design docket, we are not proposing any significant changes. Instead, as discussed by Company witness Mr. Steven V. Huso, we seek modest movements toward cost in our rate structure and are proposing a two dollar increase to the fixed monthly customer charge for residential and small commercial customers. In addition, as Mr. Gersack discusses in more detail, we propose an expansion of our low-income program. Specifically, we are proposing a new bill payment assistance program for lower income seniors, not currently served by Company, State or federal programs, and those with certified medical conditions.

B. Basic Structure of the 2016-2018 MYRP Request

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

A. After the now prior MYRP Statute was passed into law, 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 provides 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 RECENTLY CHANGE?

A. Yes, the MYRP Statute was amended during the 2015 legislative session.

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

A. The current MYRP Statute:

- Allows the utility to request the recovery of all of its capital and O&M costs;

- Allows for up to five-years of rate recovery;
- 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 ITS CURRENT REQUEST, DID IT CONSIDER BOTH THE COMMISSION'S MYRP ORDER AND THE NEW LEGISLATION SIGNED INTO LAW IN 2015?

A. Yes. Our rate request incorporates concepts from both the Order and the MYRP Statute, as shown in the Completeness Checklist I have attached as Exhibit____(AHC-1), Schedule 2. The Company notes that there are several aspects of the MYRP Order, which were not addressed by the new legislation. For matters addressed by the MYRP Order, but not addressed in the new statute, the Company tried to tailor its proposal to match the Order.

As to other aspects of the MYRP Order, the new legislation has given the Commission and intervening parties greater flexibility to craft a plan that is in the public interest. On some of the matters specifically addressed in the new legislation, our rate request utilizes these new tools.

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 2016 Test

Year. As a result, we are requesting to recover our forecasted capital and O&M for 2016.

For the 2017 and 2018 Plan Years, we use the same approach to capital investments that we used in our last case; meaning we have based the Plan Years on our capital forecasts. There is an important difference, however, in that for the current case we are requesting the recovery of all capital instead of selected capital projects. This approach is not only consistent with the new legislation, which allows a utility to propose "recovery of the utility's forecasted rate base, based on a formula, a budget forecast, or a fixed escalation rate, individually or in combination," but it is also consistent with the feedback we received in our last case. We have supported our request to recover all of our capital over the three-year period by including our full five-year capital forecast in Volume III of our Initial Filing and through the pre-filed testimony and schedules of various business unit witnesses.

For the 2017 and 2018 Plan Years, we are requesting to recover our operations and maintenance expenses. Unlike our test year, many of our Plan Year O&M expenses have been escalated by an electricity-related price index provided by Global Insight. This approach is consistent with the new legislation. Company witnesses Mr. John Mothersole and Mr. Burdick provide further discussion of these issues.

Q. DOES THE COMPANY BELIEVE ITS MYRP PROPOSAL IS GOVERNED BY THE MYRP ORDER?

A. Not exclusively. The amended MYRP Statute creates a very different construct for multi-year rate plans than the prior version of the MYRP Statute and MYRP Order and gives the Commission clear authority to approve plans that include features not necessarily consistent with the MYRP Order. While our request complies with the MYRP Order where appropriate, it primarily relies upon the amended MYRP Statute.

Q. DOES THAT MEAN YOUR PROPOSAL IS NOT FULLY CONSISTENT WITH THE MYRP ORDER?

A. Yes. While we were guided by the MYRP Order and provide financial information consistent with existing cost of service rate making principles, our MYRP requests the recovery of all capital and O&M in years two and three of the plan, which is not allowed for by the MYRP Order. As a result, the Commission will ultimately provide guidance as to the interplay between its MYRP Order and the newly enacted legislation, and in doing so will further shape MYRPs in Minnesota. We believe we have met our burden of proof to demonstrate that our rate request will result in just and reasonable rates.

Q. THE MYRP ORDER REQUIRES THE COMPANY TO WAIVE THE DEFENSE OF RETROACTIVE RATEMAKING. DO YOU HAVE ANYTHING YOU WOULD LIKE TO SAY ABOUT THIS REQUIREMENT?

A. The MYRP Order called for rate recovery in any year beyond the test year to be limited to recoveries associated with discrete capital projects. Structured in that manner, a MYRP created the potential for a backward looking prudence review of each large capital project separately, similar to the Commission's treatment of our Monticello Project in Docket No. E002/GR-10-971, where the Commission allowed the project to be included in rates, subject to refund, based on the outcome of a subsequent prudence review. It was in that context that the Commission requested the acknowledgment and the waiver as part of a MYRP. In our most recent rate case, the Company requested an MYRP consistent with the MYRP Order and made this commitment.

The current case is structured under the amended MYRP legislation. As such, both our three year Plan and five-year Offer are based on our test year and out year forecasts of capital outlays being representative for ratemaking purposes. Therefore, the concept of refunds for prudence issues should be viewed differently, especially when there are other customer protections in place such as aggregate capital true-ups or earnings tests. With that being said, we recognize that in the event of unusual circumstances, the Commission has the discretion to examine the prudence of our actions and take the steps necessary to assure just and reasonable rates.

C. Walk Through of MYRP Request

1. 2016 Test Year

Q. HOW HAS THE COMPANY STRUCTURED THE 2016 PORTION OF ITS MYRP REQUEST?

A. As Ms. Heuer discusses in detail, for 2016 we are using 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. This portion of our case is similar to past cases we have filed.

Additionally, as I previously noted, the Company is trying to avoid re-litigating issues recently decided by the Commission or consistently decided in the same manner by the Commission. Our intent with taking this approach was to create an opportunity to have a focused constructive dialogue regarding our MYRP proposal and our five-year MYRP offer.

Q. DID THE COMPANY CONSIDER ANY "RATE MODERATION" MECHANISMS TO SMOOTH OUT THE RATE IMPACTS ACROSS THE THREE YEARS OF THE MYRP?

A. Yes, but we determined not to propose any such mechanisms in this case. As the Commission recognized in our last rate case, rate moderation mechanisms defer but do not eliminate the need for rate relief.

Q. IS THE COMPANY PROPOSING ANY TRUE-UPS LIKE IN ITS LAST ELECTRIC RATE CASE?

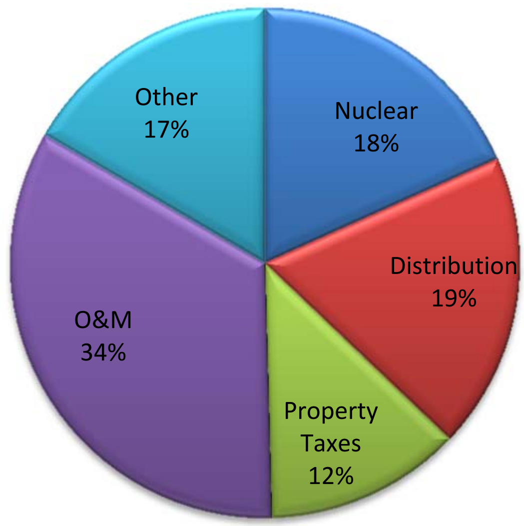
A. Yes, we are proposing a true-up for sales, property taxes and our capital related revenue requirements. Much like our last case, this case could transpire such that we will have the benefit of having actual information about our sales, and property taxes prior to implementing final rates. We believe using true-ups for limited costs helped us reach a constructive outcome in our last electric rate case and could again facilitate a constructive outcome in this case Ms. Marks discusses our sales forecast true-up in her Direct Testimony; Company witness Ms. Leanna M. Chapman discusses our property tax true-up in her Direct Testimony; and Mr. Burdick discusses our capital true-up in his Direct Testimony.

2. Plan Years 2017 and 2018

Q. TURNING TO THE 2017 AND 2018 PLAN YEARS, WHAT ARE THE MAIN DRIVERS FOR THOSE YEARS?

A. The key drivers for 2017 and 2018 are discussed by Mr. Burdick, however, collectively, they are represented below in Figure 6.

Figure 6
2017 and 2018 Revenue Requirement Drivers



Q. HOW HAS THE COMPANY STRUCTURED ITS REQUESTS FOR THE 2017 AND 2018 PLAN YEARS?

A. For 2017 and 2018, the Company considered the revenue requirements associated with its full cost of service, including capital expenditures and O&M expense. Mr. Burdick further discusses the Company's approach, including the mechanics for constructing the 2017 and 2018 Plan Years. In my testimony below, I support the structure of the 2017 and 2018 Plan Years from a policy perspective and further explain that the Company has met its burden to demonstrate that our MYRP proposal results in just and reasonable rates.

a. Capital Investments

Q. HOW HAS THE COMPANY REFLECTED ITS EXPECTED 2017 AND 2018 CAPITAL INVESTMENTS IN THE THREE-YEAR MYRP?

A. We used our capital forecasts for 2017 and 2018 to develop the capital cost of service for the 2017 and 2018 Plan Year.

Q. WHY IS THIS A REASONABLE APPROACH?

A. We believe it is a reasonable approach for several reasons.

First, the MYRP Statute allows for the recovery "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.

Second, the Company's budgeting process is iterative, rigorous, and leads to forecasts that reasonably represent the Company's investments during the forecasted period. We believe this last point to be borne out by the fact that we generally invest slightly more than our forecasted amounts. In this way our budgets are more conservative than our actual capital spending experience, and as a result provide a sound basis on which to set rates. Company witness Mr. Gregory J. Robinson discusses this further in his Direct Testimony.

Third, the Company's business area witnesses have described their respective business plans driving the key investments forecasted for their areas in 2017 and 2018. While the Company acknowledges that not every forecasted capital project will play out as we currently envision, our business units have a business plan and will pursue projects to accomplish those plans during the MYRP period. Each business unit'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.

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

A. The Company proposes the same refund mechanism approved by the Commission for the 2014 test year in our last rate case. The Commission described that mechanism as follows:

> The Company shall provide a refund to ratepayers if the Company's actual capital-related revenue requirement is less in total in 2014 than the Commission authorizes for the 2014 test year. *Such a refund would be based on the Company's total actual capital revenue requirements compared to the Commission's authorized amount*, but would not be done on a project-by-project basis. (Emphasis added).

We believe this approach strikes the appropriate balance between providing the Company with flexibility to manage its business and protecting customers.

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) since this is the first three-year MYRP considered by the Commission under the new MYRP Statute. The true-up approach used for the 2014 test year can and should be applied throughout the term of our proposed three-year MYRP for the reasons previously noted.

Q. IS THIS PROPOSAL CONSISTENT WITH THE MYRP ORDER?

A. No and I believe there are good public policy considerations supporting a departure from the MYRP Order. The MYRP Order appears to require a project-by-project review with a potential refund for each individual project that is cancelled or delayed beyond the step year. This project specific refund obligation made sense at the time since only specific capital projects and related O&M could be recovered under the MYRP Order. In this way the MYRP Order created a multi-year rate construct that acted more like a capital rider.

When we can recover all of our capital investments, as allowed under the amended MYRP Statute, a project specific refund mechanism is the wrong construct. Our business units forecast to do projects of all sizes and for a variety of reasons. At times we could expect to do thousands of projects. A project specific refund obligation would require we do each project as forecasted. Over the course of a year, let alone several years, we need the flexibility to respond to emerging demands or needs and to reprioritize work.

We believe the focus should be on whether our capital forecasts in the second and third years are representative. An aggregated true-up provides us with the business flexibility to operate our systems safely and reliably while protecting our customers' interests.

b. Passage of Time

Q. DOES THE COMPANY'S THREE-YEAR MYRP REQUEST 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 2017 and 2018 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 2017 and 2018, and as a result, the revenue requirement impacts of the passage of time. Company witnesses Mr. Burdick and Ms. Lisa H. Perkett discuss this further in their respective Direct Testimonies.

c. Operations and Maintenance

Q. HOW HAS THE COMPANY ADDRESSED O&M EXPENSES IN THE 2017 AND 2018 PLAN YEARS?

A. Our request to recover 2017 and 2018 Plan Year O&M expenses was developed largely from specific electric utility price index factors provided by IHS Global Insight, Inc (IHS). For the few exceptions where an IHS factor was not available or different treatment was warranted, we used an IHS composite factor, the Company's forecast, or our 2016 budget level. Mr. Burdick and Mr. Mothersole primarily support our request to recover O&M expenses for the 2017 and 2018 Plan Years.

Q. HOW DID THE COMPANY DECIDE TO USE IHS ESCALATION FACTORS?

A. The amended MYRP Statute specifically provides for the "recovery of operations and maintenance expenses, based on an electricity-related price index or other formula." We selected IHS escalation factors because of our familiarity with them and their reputation in the industry.

Q. HAS THE COMPANY ALSO PROVIDED ITS O&M FORECAST FOR 2017 AND 2018 AND, IF SO, HOW DO THOSE FORECASTS COMPARE TO THE COMPANY'S REQUEST?

A. Yes, we have developed and included those forecasts in Volume 6 of our

Application. Our forecast closely matches our requested recovery for O&M expenses in 2017 and is lower than our requested recovery for O&M expenses in 2018.

Q. WHY IS IT JUST AND REASONABLE TO SET RATES ON THE BASIS OF O&M INDEXES IF THE COMPANY CURRENTLY FORECASTS LOWER EXPENSES?

A. First, the MYRP Statute specifically provides for the use of such factors in building a MYRP proposal. Second, the IHS factors are well established and are proven for reasonably escalating expenses. Third, as demonstrated by our various business unit witnesses, the Company's O&M forecasts have proven to be conservative estimates during the past few years. Meaning we typically spend more than we forecast. Together, we believe these reasons support our approach of relying on the IHS factors.

d. Revenues and Margins

Q. DID THE COMPANY INCORPORATE ANY OFFSETTING REVENUES THAT LOWER THE 2017 AND 2018 PLAN YEAR REVENUE REQUIREMENTS?

A. Yes. By developing our 2017 and 2018 Plan Year revenue requirements using a full cost of service approach, we attempted to capture the full array of issues that impact those revenue requirements – both items that increase revenue requirements and items that decrease them. Mr. Burdick discusses this further in his testimony.

Q. HOW DO DECOUPLING AND SALES INTERACT WITH THE 2017 AND 2018 REVENUE FORECAST?

A. For all classes, we are using the 2016 sales forecast for the 2017 and 2018 Plan Years. Ms. Marks explains that the Company is forecasting nearly flat sales for our decoupled classes. Decoupling will provide a true-up for any growth or decline that occurs for decoupled classes. However, for the non-decoupled classes, Ms. Marks explains that we do anticipate some sales growth. Therefore, our 2017 and 2018 Plan Years incorporate those revenues into the development of our revenue requirements, as Mr. Burdick discusses in his testimony. We are proposing a true-up of non-decoupled sales to the forecast, so that any unexpected increases in revenues will also be captured and offset our revenue requirements in those years.

Q. ARE THE MANKATO ENERGY CENTER II POWER PURCHASE AGREEMENT PAYMENTS REFLECTED IN THE 2018 PLAN YEAR?

A. Yes, at the time we developed the rate case budgets and forecasts, the Company expected the Calpine Mankato generation unit would go into service in 2018. Under the power purchase agreement, the Company is obligated to make capacity payments to Calpine once the generating unit goes into service. Since the capacity payments for this power purchase are collected through base rates, we included them in the 2018 Plan Year.

Q. DOES THE COMPANY STILL EXPECT THE MANKATO ENERGY CENTER II TO BE IN-SERVICE BY 2018?

A. This past summer the Company and Calpine entered into a PPA amendment under which the commercial operation in-service date for the Mankato Energy Center II was extended to 2019. This was done to preserve the Company's contractual rights while the North Dakota commission determines whether it should provide the Company with an Advance Determination of Prudence for the PPA costs. That regulatory proceeding is still on-going so it is difficult to speculate as to the plant's in-service date. As a result, we have reflected the capacity payments starting in 2018 with an understanding that we will update the case when the situation becomes more certain.

e. 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 an 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 return on equity (ROE). Company witness Mr. James Coyne discusses this further in his Direct Testimony.

Q. IS THE COMPANY PROPOSING AN ADJUSTMENT TO ITS REQUESTED 10.00 PERCENT ROE FOR THE 2017 AND 2018 PLAN YEARS?

A. No. While we believe the new legislation allows for such adjustments, and that an increase could be appropriate in light of macro-economic considerations, we are not proposing any adjustments to the requested ROE. Our intent by proposing a fixed ROE is to limit the number of potentially contested issues in this proceeding.

f. Rate design

Q. DOES THE COMPANY PROPOSE ANY SIGNIFICANT RATE DESIGN CHANGES FOR THE 2017 AND 2018 PLAN YEARS?

A. No. Mr. Huso discusses the Company's overall approach to rate design, including our approach to the 2017 and 2018 Plan Years, in his testimony.

3. 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. We already have 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 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. Yes. When the legislature amended the MYRP statute, it specified that the Commission may require a utility under such a plan to provide a set of reasonable performance measures and incentives "that are quantifiable, verifiable, and consistent with state energy policies." Consistent with this legislative direction, we propose performance measures addressing customer satisfaction, providing customers more choices, products and services, environmental stewardship, and customer outage experience.

Q. CAN YOU DISCUSS THE FIRST MEASURE, REGARDING "THE CUSTOMER EXPERIENCE"?

A. As I mentioned above, we already report on our reliability performance and customer complaint levels through both our QSP tariff annual report as well as our annual service quality report required under the Minnesota rules with all electric utilities. Thus, we thought a performance metric linked directly to customer responses would be complementary to our existing customer experience and satisfaction efforts. Accordingly, we propose to report on customer satisfaction levels with power quality and reliability as measured by JD Powers. We would measure whether customers believe we provide quality electric power, whether we promptly restore power after outages, whether we keep customer informed about outages, and our overall provision of power quality and reliability.

Q. WHAT DOES THE COMPANY PROPOSE WITH RESPECT TO ENABLING CUSTOMER CHOICES?

A. We understand that customers seek increased access to new services, products, and technologies. With this in mind, we propose a Customer Choice Pilot Program metric that sets a baseline for the number of new pilot programs we will release per year. We are proposing to develop and release two new pilots each year during the MYRP.

Q. AND WHAT DOES THE COMPANY PROPOSE WITH RESPECT TO

ENVIRONMENTAL STEWARDSHIP?

A. We propose a carbon emission reduction goal consistent with our October 2, 2015 Integrated Resource Plan Reply Comments. Specifically, we propose a 37.1 percent (or 19.2 million system tons) reduction in carbon dioxide emissions below 2005 levels by 2020. Our proposed metric is based on reductions in carbon dioxide emissions associated with our electric service regardless of whether we own the generating facility or purchase the power from third parties.

Q. CAN YOU DISCUSS THE FINAL METRIC, REGARDING CUSTOMER OUTAGES?

A. In an effort to recognize our upcoming grid modernization efforts and their impact on our customer's experience, we propose to report on improved reliability through the roll out of automated feeders. Specifically, we would measure the non-storm normalized customer minutes out (CMO) saved with automated switching or FLISR (Fault Location Isolation and service restoration). Our grid modernization plans and FLISR are further discussed in Ms. Bloch's testimony as well as our Biennial Distribution Grid Modernization Report filed on October 30, 2015.

Q. DOES THE COMPANY PROPOSE TO TIE ANY FINANCIAL INCENTIVES OR PENALTIES TO THESE MEASURES?

A. Not at this time. This is the first three year (or five-year) MYRP the Commission will consider. The Company proposes putting these performance measures in place, monitoring our performance under them, and learning from this experience. Future MYRPs can then use the learnings from this case to design and implement financial incentives or penalties, if such measures are desired.

b. Low-income proposal

Q. HAS THE COMPANY ALSO INCLUDED A NEW LOW-INCOME AFFORDABILITY PROPOSAL AS PART OF ITS MYRP?

A. Yes. As further discussed by Mr. Gersack and Mr. Huso, we propose a new program in line with our efforts to expand services and products for our customers and to respond to the direction provided in the amended MYRP Statute.

Q. WHAT DOES THE AMENDED MYRP STATUTE STATE ABOUT LOW INCOME PROGRAMS?

A. That statute provides that a utility proposing a MYRP may propose "tariffs that expand the products and services available to customers, including, but not limited to, an affordability rate for low-income residential customers."

Q. PLEASE DESCRIBE THE COMPANY'S NEW LOW INCOME PROPOSAL.

A. The Company has a long tradition in this area, including our PowerON program. However, we believe an additional program can be designed that can better serve customers not currently reached by Company, State or federal energy assistance efforts. The proposal set forth by Mr. Gersack would assist seniors and those with chronic or severe medical conditions and target an income level just above the 50 percent state median income guidelines currently used for energy assistance.

c. Riders

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

A. Yes, Ms. Heuer discusses the Company's proposed ratemaking treatment associated with each of the riders in use, including the Company's proposal to move recovery of two major transmission projects, the CapX2020 Fargo and Brookings projects, from the Transmission Cost Recovery (TCR) Rider to base rates upon implementation of final rates in this proceeding.

Q. WHY IS THE COMPANY PROPOSING TO ROLL THE CAPX2020 BROOKINGS AND FARGO PROJECTS INTO BASE RATES 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 impact to customers from the Company recovering the project costs through the TCR 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 will result in a better matching of rate recovery of these two projects between base rates and the TCR Rider. It is also worth noting that recovery of these projects through the TCR Rider during the interim rate period is relatively simple and straightforward. In fact, the current TCR Rider rates, implemented on July 1, 2015, were calculated over an 18 month period, including calendar year 2016 when interim rates will be in effect.

Q. CAN YOU BRIEFLY DESCRIBE THE COMPANY'S APPROACH FOR ROLLING THE TWO CAPX2020 PROJECTS INTO BASE RATES DURING FINAL RATE IMPLEMENTATION?

A. Our approach essentially starts with an interim rate adjustment that excludes these two projects from interim rates and an update to our recently filed TCR petition to confirm we will be recovering the projects through the rider.

When we implement final rates, which will include the CapX2020 Brookings and Fargo projects, we will simultaneously remove these projects from that mechanism and reduce our recovery through the TCR Rider. 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 Meadow Wind and Wind2Battery projects recovered through the RES Rider in our 2010 rate case (Docket No. E002/GR-10-971).

As all parties and the Commission learned in that case, a thorough discussion of the relationship between rider rates and final rates early in the proceeding can ensure a full understanding of the issues and the impacts associated with the transfer of recovery. We believe we have learned from that experience and for that reason are thoroughly discussing our proposal in testimony and our interim rate petition. The Company will continue to provide updated information on the anticipated impact of this transfer on final rates throughout this proceeding.

Q. IS THE COMPANY INCLUDING ANY NEW PROJECTS IN RIDERS?

A. Yes. In our most recent Renewable Energy Standard (RES) Rider filed September 1, 2015 in Docket No. E002/M-15-805, we requested to recover the capital costs and expenses associated with our Company-owned Courtenay

Wind project. The Courtenay Wind Farm is a 200 MW wind resource in North Dakota whose costs the Commission has stated:

> are properly recoverable under the automatic rate adjustment authorized in Minn. Stat. § 216B.1645, subd. 2a. In Xcel's case this adjustment is the Renewable Energy Standard Rider; all amounts booked to this rider are examined and trued up annually, both to ensure prompt recovery of renewable-energy-standard compliance costs and to ensure the highest levels of accuracy, efficiency, and accountability.

We expect the Courtenay Project to begin construction in the third quarter of 2015, and it is projected to be in-service in December 2016. Due to the lateness in the year of the in-service date, the majority of the revenue requirements will occur in 2017.

Q. WHY IS THE COMPANY SEEKING TO RECOVER THE COURTENAY PROJECT COSTS THROUGH THE RES RIDER?

A. We appreciate that the MYRP Order encourages the transitioning of cost recovery from riders to base rates. With the Courtenay project, however, the RES rider provides greater certainty around cost recovery. This is because the majority of the revenue requirement impact of this project will be in 2017, and even though we have requested interim rates in 2017, we are cognizant that the Commission has never granted a "second year" of interim rates under the amended MYRP Statute.

Q. IS THE COMPANY PROPOSING TO INCLUDE ANY OTHER NEW PROJECTS IN RIDERS?

A. Yes. We are proposing to recover two projects in our new grid modernization rider that was initiated with the 2015 legislation that amended the existing Transmission Cost Recovery (TCR) rider. As discussed in our October 30, 2015 Biennial Distribution Grid Modernization Report, we are seeking to certify our Advanced Distribution Management System (ADMS) and Belle Plaine battery project through the rider.

Q. DOESN'T THE MYRP ORDER CALL FOR UTILITIES FILING MYRPS TO PROPOSE RESTRUCTURING OF ITS RIDERS AND MOVING COST RECOVERY TO BASE RATES WHERE POSSIBLE?

A. Yes, but neither the MYRP Order nor the MYRP Statute prohibit the continued use of riders. To the contrary, the amended MYRP Statute specifically recognizes that additional rider-type recovery mechanisms may be important in MYRPs. Specifically, the amended MYRP Statute allows utilities filing plans to propose "adjustments to the rates approved under the multiyear plan for rate changes that the commission determines to be just and reasonable, including, but not limited to, changes in the utility's cost of operating its nuclear facilities, or other significant investments not addressed in the plan."

From a policy perspective, we would encourage stakeholders to view MYRPs and riders as complementary of one another as opposed to mutually exclusive choices. In an environment of flat sales and on-going, needed capital investments, base rates can focus on more routine capital work while riders can focus on larger capital projects, 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. This is a healthy approach that has been used in other states.

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

Q. DOES THE COMPANY ALSO PROPOSE ANY "TRUE-UP" MECHANISMS DURING THE TERM OF ITS PLAN, TO ENSURE THAT CUSTOMERS DO NOT PAY MORE THAN NECESSARY FOR THOSE ITEMS COVERED BY THE TRUE-UP?

A. Yes. The Company proposes three such true-ups, each modeled after true-ups approved in our most recent rate case. First, as I discussed above, the Company proposes a capital true-up. Under this mechanism, if the Company's actual capital-related revenue requirement is less in total for any year of the MYRP than the Commission's authorized amount, the Company would refund that difference to ratepayers. This can assure the Commission and customers that the Company does not "over-recover" for capital related items during the term of its MYRP.

Second, as Ms. Marks discusses, the Company proposes a true-up of the Company's sales for its non-decoupled classes. The Commission approved a broader sales forecast true-up in our last case. For this case, however, the decoupling mechanism will already act to true-up sales to the classes covered by that mechanism. Therefore, the more limited true-up is appropriate and can ensure that rates have been set appropriately from both the customer and Company perspective.

Finally, as Ms. Chapman explains, the Company recommends that the Commission again approve a property tax true-up to ensure that customers pay only for our actual property taxes incurred, no more and no less.

Mr. Burdick discusses each of these mechanisms and proposes a schedule for the Company's filings, and for review and implementation of any required adjustments to rates based on that review.

e. 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. Mr. Burdick describes the compliance filings the Company proposes to make and a proposed schedule for review of those filings. These filings, together with the Company's sales and decoupling true-up reports and our May 1 Jurisdictional Annual Report (JAR) will provide the Commission and parties a wealth of information on which to assess the accuracy of the estimates used in the development of the MYRP.

f. Refund commitments

Q. WHAT DOES THE MYRP ORDER STATE WITH RESPECT TO POTENTIAL REFUNDS TO CUSTOMERS DURING THE TERM OF A MYRP?

A. The MYRP Order discusses one potential general refund obligation and one more specific potential refund obligation. First, the MYRP Order states that a utility proposing a MYRP should provide "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." I discussed our thoughts on this requirement earlier in my testimony.

Second, the MYRP Order envisions "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." I previously discussed our deviation from this requirement and proposal to use an overall capital true-up as was approved in our last rate case to provide our customers with the same protections.

Q. DOES THE COMPANY PROPOSE OTHER POTENTIAL REFUNDS?

A. Yes, the Company's proposed true-ups for property taxes and for non-decoupled class sales could lead to refunds (or surcharges) to customers during our MYRP.

g. Commitment to not file during term of Plan

Q. THE MYRP ORDER ALSO 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 stable and predictable rates for a period of time and avoid the need for serial rate case filings.

h. 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, unless the Company files another MYRP 60 days prior to the conclusion of the term and proposes new interim rates.

4. 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 unit 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 employed a hybrid approach that utilizes well-founded electricity utility index factors, where applicable. Those factors have closely tracked our actual experiences over time. For items where such factors were not available, we have either held our Plan Years at 2016 levels or we have utilized our forecast, as appropriate.

Given our full cost of service approach, we also have incorporated revenue or other offsets that reduce our revenue requirements in the plan years. This approach has resulted in modest and stable rate requests for the 2017 and 2018 Plan Years that should assure the affordability of our energy services over the term of the plan. Moreover, we propose an energy assistance program as part of our plan, to assist seniors and customers with medical needs, who do not currently receive Company, State or federal energy assistance.

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. We are requesting the Commission approve an interim rate increase of approximately 5.5 percent beginning January 1, 2016. We expect this proceeding could last until 2017. For that reason, and consistent with the amended MYRP Statute, we are also proposing an additional interim rate increase of approximately 1.5 percent beginning January 1, 2017.

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, we believe 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 a likely lengthy proceeding. This is especially the case here where half of the 2016 deficiency is for rate moderation tools and investments that our customers are already benefitting from, and the other half of the deficiency is largely for investments that will be in-service before final rates are likely to be in effect.

Q. AND WHY IS IT REASONABLE TO HAVE A SECOND INTERIM RATE INCREASE IN 2017?

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 2016. This means that we will still be making increasing investments and facing increased costs in 2017. To be positioned to meet our customers' needs, an interim rate increase is appropriate. I would also note that the new MYRP Statute specifically allows for such an increase, reflecting the legislature's recognition that MYRP cases can extend more than one year and that a utility filing such a plan should be allowed interim rate recovery based on its second year revenue requirements.

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO ITS 2016 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 CapX2020 Brookings and Fargo projects. We discuss the adjustments to our 2016 interim rate request in our Interim Rate Petition. Ms. Anne Heuer also discusses the adjustments in her Direct Testimony.

Q. WHAT ADJUSTMENTS HAS THE COMPANY MADE TO ITS 2017 INTERIM RATE REQUEST?

A. We took a conservative approach with our 2017 interim rate request. Specifically, our request only reflects our incremental capital and capital-related O&M expenses. It does not request other O&M expenses. In this way our approach is consistent with the MYRP Order. It also recognizes that the Commission has not previously approved recovery of non-capital O&M expenses in the second year of a MYRP even though we believe 2017 O&M expenses are the same nature and kind as the expenses we will incur in 2016.

VI. FIVE-YEAR MYRP OPTION

A. Potential Benefits of a Five-Year Plan

Q. DO YOU HAVE ANY INTRODUCTORY COMMENTS ABOUT THE FIVE-YEAR OPTION?

A. Yes. The five-year MYRP option is a completely separate proposal from our three-year MYRP request. Meaning it is not simply two additional years added onto the three-year MYRP request. Instead the five-year MYRP option is a test year built from our 2016 cost of service plus four static, formulaic, incremental rate increases resulting in a discounted rate increase when compared to our five-year forecast.

Q. WHY IS THE COMPANY OFFERING AN ALTERNATIVE FIVE-YEAR MYRP OPTION?

A. We offer this plan because we believe a five-year plan can provide substantial benefits to customers, regulators, other stakeholders and the Company -- benefits that are not only longer in time than a three year MYRP can provide but that are greater in magnitude as well. Moreover, a five-year plan can provide greater simplicity in ratemaking by taking a fundamentally different approach when structuring the plan. Given the longer time frame and the greater revenue certainty provided by the plan, we can provide a "discounted" revenue deficiency, when compared to cost of service ratemaking.

Q. CAN YOU DEMONSTRATE THESE BENEFITS?

A. Yes. Figure 7 and Table 1 below compare the Company's five-year offer to our three-year MYRP and inflation.

Figure 7

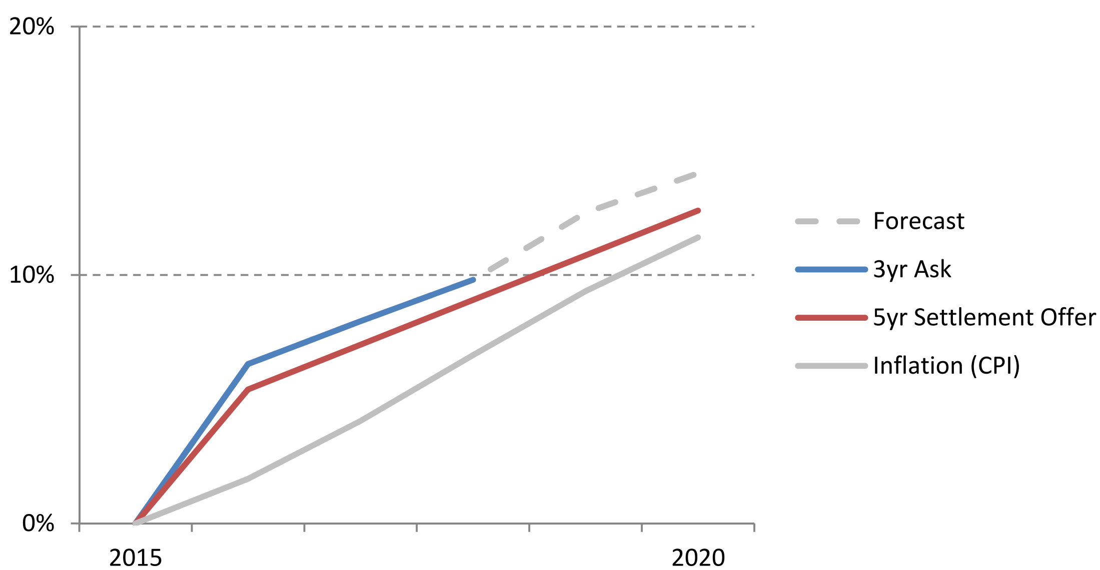


Table 1

	2016	2017	2018	2019	2020	TOTAL
3yr Ask / Forecast	6.4%	1.7%	1.7%	2.7%	1.6%	14.1%
5yr Offer	5.4%	1.8%	1.8%	1.8%	1.8%	12.6%
Inflation (CPI)	1.8%	2.3%	2.7%	2.6%	2.2%	11.5%

I note the percentages in Table 1 are incremental increases over 2016.

Q. DO YOU HAVE ANY COMMENTS ABOUT FIGURE 7 AND TABLE 1?

A. Yes. Figure 7 and Table 1 demonstrate that our five-year option provides a front-end and back-end rate discount when compared to our three-year MYRP. We are able to provide this type of discount because of the longer runway provided with a five-year rate compact. Additionally, the five-year option provides rate increases which are lower than inflation from 2017-2020. Essentially, we are proposing a rate shape that provides incremental price increases for an essential service akin to the price increases that occur for commodities due to inflation.

Q. IN ADDITION TO PROVIDING LOWER RATES, HOW WOULD CUSTOMERS, REGULATORS OR OTHER STAKEHOLDERS BENEFIT FROM SUCH A PLAN?

A. Customers have expressed a desire for greater certainty and predictability in their bills. With a five-year MYRP, customers will have an even longer term view of their rates than they can be assured of with a three year plan. This longer term plan can also lock in more stable and more affordable rate adjustments for customers, when compared to the more abrupt changes in rates that come from general rate case filings.

A five-year MYRP also provides customers, regulators and other stakeholders a longer-term view of a utility's investment and management plans and an increased ability to participate in critical long-term policy discussions. The regulatory efficiencies available in a longer term MYRP provide an overall benefit by enabling all parties to focus on these key issues, rather than constantly litigating rate cases. Such a less litigious environment can also lead to more collaboration, with all parties focused on achieving key policy goals and delivering customer benefits.

In addition, longer term plans facilitate a utility becoming even more responsive to its customers' needs. The certainty provided by the plan and the reduced regulatory lag encourages creative investment in the utility system that allows for implementation of new and innovative technologies.

At the same time, regulatory oversight is maintained in a five-year MYRP through earnings tests and performance metrics. In this way, regulators and other interested parties can stay fully informed and be assured of the reasonableness of the utility's rates and service levels.

Q. WHAT IS THE COMPANY'S VIEW OF SUCH A LONG-TERM PLAN?

A. To say the least a long-term rate compact, such as our five-year MYRP offer, will challenge our business to operate within an aggressive revenue cap. With that being said, a long-term plan can help our customers, policy makers, regulators and us work collectively to meet the evolving customer expectations and changes in the industry landscape I previously discussed, such as transforming our generation fleet and modernizing our distribution grid.

Q. HAS THE COMPANY PROVIDED INFORMATION IN ITS APPLICATION THAT CAN INFORM AND SUPPORT A FIVE-YEAR MYRP?

A. Yes. Because we believe a five-year rate plan can provide greater value and benefits for all stakeholders, we have included our full five-year forecast for 2016 through 2020. We also offer a rate setting approach that we believe can deliver those benefits. We have included this information and this offer now, so that the Company and interested parties can further develop the record and explore settlement and so that the Commission can have this longer-term plan available if it agrees that it provides public interest benefits.

B. The Company's Five-Year MYRP Offer

Q. IS THE COMPANY'S FIVE-YEAR OFFER SIMPLY AN "EXTENSION" OF ITS THREE YEAR MYRP REQUEST?

A. No. The five-year offer puts forth a fundamentally different approach and different concept than our three year MYRP request.

Q. HOW DID THE COMPANY DEVELOP ITS OFFER FOR A FIVE-YEAR MYRP?

A. We considered several factors. But importantly, we looked to structure an offer that can clearly provide benefits to our customers. With that as our guide, we developed an offer that uses our interim rate request as the starting point of the first year rate increase. From there we identified an annual percentage increase that would be sustainable over the remaining four-year period but encouraged us to strategically and more aggressively manage our costs. The proposed 1.8 percent annual rate increases from 2017-2020 are the bare minimum for us to continue providing the service our customers expect from us while pursuing policy goals and offering more choices to our customers.

Q. WHAT DOES THE COMPANY PROPOSE?

A. Table 2 presents the Company's offer for a five-year rate plan, with the percent and revenue increases compared to present revenues.

Table 2
Five-Year MYRP Offer

	2016	2017	2018	2019	2020
Incremental Percent Increase	5.4%	1.8%	1.8%	1.8%	1.8%
Incremental Revenue Increase	$163.7M	$54.6M	$54.6M	$54.6M	$54.6M

This offer would set our 2016 revenue requirement at our interim rate request level and then provide level annual increases for 2017 through 2020. By doing so, we provide a nearly one percent reduction in rates for 2016, compared to our three year MYRP request.

Q. DOES THIS OFFER REFLECT A STRICT COST OF SERVICE APPROACH TO RATE SETTING?

A. No. As demonstrated in the graph presented earlier, a strict cost of service approach would lead to higher rate increases than offered here. Our three-year MYRP was built on a cost of service basis and shows our revenue requirements increases of $297.1 million for 2016 through 2018, compared to the $272.9 million increase for those same years in our offer. In addition, as I discussed above, our forecasts show increased investments in 2019, that would put further pressure on our revenue requirements under a cost of service approach. These savings to customers, compared to cost of service ratemaking, demonstrate the ratepayer and public interest benefits of this offer.

Q. IS SUCH A PLAN CONSISTENT WITH THE MYRP STATUTE?

A. Yes. The MYRP Statute provides broad authority for the Commission to approve a MYRP, provided that it finds that the plan establishes just and reasonable rates for the utility. The statute allows a utility to propose plans with the capital related items based on "the utility's forecasted rate base, based on a formula, a budget forecast, or a fixed escalation rate, individually or in combination" and with the O&M related items "based on an electricity-related price index or other formula." Our five-year offer is not only consistent with these approaches but, as demonstrated by Mr. Burdick's testimony, provides lower rates than would be provided under a reasonable "formulaic" approach.

Q. ARE THERE ASPECTS OF THE COMPANY'S THREE-YEAR MYRP REQUEST THAT WOULD CARRY OVER TO THE FIVE-YEAR OFFER?

A. Yes. We continue to recommend the new low-income assistance program discussed in my earlier testimony. While our offer provides lower rate increases than our three-year request, we believe the low-income offering provides benefits that should be extended to the seniors and others that would be eligible for this new assistance. Our five-year offer also incorporates the performance metrics I have discussed, as an additional tool for the Commission and other stakeholders to monitor our performance over the term of the plan.

Q. ARE THERE CHANGES THE COMPANY SUGGESTS IF A FIVE-YEAR APPROACH IS ADOPTED RATHER THAN A THREE-YEAR PLAN?

A. Yes. While a five-year plan offers great benefits, Mr. Coyne also explains that such a plan presents greater risks for the Company. From a customer or regulator perspective, a five-year plan could also be viewed as creating a greater possibility of over-earning by the Company. Therefore, to ensure that all parties' interests are considered and balanced, we recommend that a five-year plan also include an earnings test and sharing mechanism, tied to an indexed return on equity. This earnings test and sharing mechanism would replace the individual true-up mechanisms (for capital revenue requirements, property taxes and non-decoupled class sales) recommended in our three-year MYRP request.

Q. PLEASE DESCRIBE HOW SUCH AN EARNINGS TEST AND SHARING MECHANISM WOULD WORK.

A. A variety of different methods can be used in structuring this test and sharing mechanism, from simple and straightforward to complex and detailed. We recommend a simple, straightforward approach that would determine the Company's actual earned ROE and compare that result to the indexed ROE, calculated in the manner described by Mr. Coyne. This test would be applied to calendar year results beginning in 2017, with the Company initiating the review coincident with its May 1, 2018 jurisdictional annual report.

Q. AND WHAT SPECIFICALLY DOES THE COMPANY PROPOSE?

A. The Company proposes that to the extent the Company's actual earned ROE falls within a band of 50 basis points on either side of the indexed ROE, no sharing would occur. If the actual earned ROE exceeded the indexed ROE by more than 50 basis points, ratepayers would receive a refund of 50 percent of that excess amount. Similarly, if the actual earned ROE fell more than 50 basis points below the indexed ROE, the Company would be allowed to recover 50 percent of that shortfall.

Q. CAN YOU PROVIDE A SIMPLE ILLUSTRATION?

A. Sure. Let's start with 2018. At the beginning of 2018, the Company would advise the Commission of the new authorized ROE that will be used for the 2018 earnings test. In 2019, the Company would submit its 2018 jurisdictional report that will include the actual earned ROE for the year based on actual revenues, expenses and costs. Should the actual ROE be higher than the authorized ROE for 2018 by 51 basis points, the Company would share 50 percent of the earnings above the 50 basis point band with customers.

Q. HOW ARE ITEMS SUCH AS SALES, DECOUPLING, PROPERTY TAXES, PASSAGE OF TIME ADJUSTMENT, CHEMICAL COSTS AND DEPRECIATION LIVES ACCOUNTED FOR?

A. The earnings test will account for each of these items. If these items cause our revenue needs to be less than the proposed rate shape in a given year, our actual ROE will be higher than the authorized ROE and as a result we will share the excess earnings.

Q. WHAT OTHER ADJUSTMENTS DOES THE COMPANY SUGGEST IF A FIVE-YEAR PLAN IS APPROVED?

A. As Company witness Ms. Lisa. R. Peterson explains, if a five-year plan is adopted, the Company recommends that the Commission extend our decoupling plan to five-years as well, so that these two ratemaking features are aligned. In addition, Ms. Peterson explains that in a five-year plan the "cap" on the decoupling adjustment should be increased from three percent to five percent for the last two years.

Q. HOW WOULD THE COMPANY PROPOSE TO TREAT RIDERS DURING THE TERM OF A FIVE-YEAR PLAN?

A. We propose to treat the use of Riders consistent with the manner in which as Ms. Heuer and I have discussed riders in our three year MYRP request. As I discussed earlier, riders and MYRPs should be viewed as complementary tools for assuring just and reasonable rates. In fact, the appropriate use of riders becomes even more important in a five-year plan and the MYRP Statute recognizes that by providing that a MYRP may allow for "adjustments to the rates approved under the multiyear plan for rate changes that the commission determines to be just and reasonable, including, but not limited to, changes in the utility's cost of operating its nuclear facilities, or other significant investments not addressed in the plan." Such a provision is a critical component of any five-year plan. Without the ability to adjust rates in this manner, a MYRP no longer provides balance and shifts unacceptable risk to the utility.

Q. HOW DOES THE COMPANY PROPOSE THE FIVE-YEAR OPTION BE MOVED FORWARD?

A. We ask the Commission to encourage parties to negotiate the five-year option in good faith. The Commission could also encourage the use of a formal mediation process to facilitate the negotiation.

Q. PLEASE SUMMARIZE THE BENEFITS OF THE COMPANY'S VIEW OF A FIVE-YEAR PLAN AND ITS OFFER.

The offer we provide delivers rate relief to our customers in 2016 and over the term of the plan, when compared to traditional cost of service ratemaking. The earnings test and sharing mechanism we propose, together with the performance metrics we have set out and the Commission's ongoing oversight of our performance – both operationally and financially – can ensure safe, reliable service just and reasonable rates throughout the term of the plan. This plan is simple and straightforward, without sacrificing any ratepayer protections. When then considering the additional benefits of a five-year plan that I have discussed above, we believe such a plan merits serious consideration. We believe it would position all parties to work together and best serve our customers, while meeting the challenges of today's dynamic energy industry.

Q. WOULD THE COMPANY ACCEPT AN FIVE-YEAR MYRP IF THE COMMISSION WERE TO ADOPT ONE?

A. Yes, provided that the plan is consistent with the terms and principles I have outlined.

VII. FRAMEWORK OF FILING AND COMPLETENESS CHECKLIST

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 2E include the Direct Testimony and supporting schedules of each of the witnesses.
- Volume 2F contains our proposed Tariff sheets for the 2016 Test Year and the 2017 and 2018 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. This differs from our last rate case filing, where we provided certain information for the Test Year only and providing certain other information for both the Test Year and the (2015) Step Year. While the Commission Rules do not require this information for all three years, the Rules were written prior to the MYRP Statute being signed into law. Therefore, we have provided more expansive information in this case so that parties and the Commission have complete information before them related to our MYRP request.
- Volume 4 includes the workpapers primarily supporting the cost of service studies for the 2016 Test Year and 2017 and 2018 MYRP Plan Years, prepared at the direction of Ms. Heuer.
- Volume 5 includes our Budget Summary and Correspondence.
- Volume 6 includes our Budget Documentation, including our forecasted information for 2016-2020, so the parties and the Commission have full forecast information for the five-years covered by our five-year MYRP Offer.

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

A. Yes. I have attached our Completeness Checklist as Exhibit____(AHC-1), Schedule 2.

VIII. 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:

- Charles Burdick, who provides further discussion of the details related to the Company's MYRP request.
- John Mothersole, of Global Insights, who provides testimony regarding the Global Insights indexes used in developing the Company's MYRP Proposal.
- Anne Heuer, who sponsors the overall revenue requirement for the rate case. Ms. Heuer also sponsors the schedules supporting our income statement, rate base, revenue deficiency, and jurisdictional allocations. Her schedules incorporate and reflect the recommendations of a number of our witnesses, including the cost of capital and sales forecast. Ms. Heuer also supports certain cost recovery proposals.
- Brian Van Abel, who sponsors our capital structure, cost of debt, and overall cost of capital recommendations and provides testimony regarding investor relations.
- James Coyne, of Concentric Energy Advisors, who testifies on the Return on Equity and Rate of Return, including capital structure, and the cost of debt.
- Janelle Marks, who provides testimony supporting the Company's sales forecast for the 2016 Test Year and also testifies regarding sales in the 2017 and 2018 Plan Years. These sales figures are then used in Ms. Heuer's determination of the revenue deficiency.

- Gregory Robinson, who testifies on the Company's budgeting process;
- Timothy O'Connor, who sponsors testimony regarding our nuclear program and the reasonableness of our nuclear-related capital investments and O&M costs.
- Steven Mills, who sponsors testimony discussing our capital budget and the O & M expenses for the Energy Supply business unit. Mr. Mills also provides information with respect to the performance of our generation fleet and steps we are taking to improve performance and operate more efficiently.
- Ian Benson, who sponsors testimony regarding the budgeted investments in our transmission system, as well as associated O&M expenses.
- Kelly Bloch, who sponsors testimony regarding our investments in our distribution system, as well as associated O&M expenses.
- David Harkness, 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.
- Adam Dietenberger, who presents our Cost Assignment and Allocation Manual, and discusses cost allocations between business units and jurisdictions, as well as from Xcel Energy Services Inc.
- Robert Miller, who sponsors testimony regarding the Company's insurance program.
- 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.

- Richard Schrubbe, who sponsors and provides testimony about the level of our pension cost request and associated pension accounting.
- George Tyson, who testifies regarding the management of the Company's pension trust funds, including a discussion of our target asset allocations and our investment returns. Mr. Tyson also discusses the Company's risk management strategy
- Evan Inglis, of Nuveen, who provides an independent, 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.
- Gary O'Hara, who sponsors testimony regarding employee expenses.
- Lisa Perkett, who provides testimony regarding depreciation and remaining lives for all plant and plant-related items. Ms. Perkett also presents testimony regarding how the Company's MYRP request accounts for the passage of time.
- Leanna Chapman, who sponsors testimony regarding our property tax expenses.
- Michael Gersack, 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.
- Lisa Peterson, who provides testimony on decoupling and how it fits within our MYRP proposal.

- Michael Peppin, who sponsors our class cost of service study and discusses the minimum distribution study issues required to be addressed in this case.
- Steven Huso, who sponsors the general rate design and tariff changes we present in this case.

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Aakash H. Chandarana
Regional VP, Rates and Regulatory Affairs
NSPM

Aakash Chandarana is Regional Vice President of Rates and Regulatory Affairs – Minnesota. He is responsible for Xcel Energy's regulatory filings with the utility commissions in Minnesota, North Dakota and South Dakota.

Chandarana joined Xcel Energy in 2013 as Lead Assistant General Counsel – Regulatory North where he was the lead regulatory attorney for Xcel Energy's operations in Minnesota, North Dakota, South Dakota, Wisconsin and Michigan. He represented Xcel Energy in regulatory proceedings before the Minnesota Public Utilities Commission and handled most issues related to rate cases, nuclear issues, fuel costs, depreciation, renewable energy, and resource planning. In January 2015, he was promoted to his current role. He has more than 10 years of experience in energy and regulation.

Chandarana serves on the Finance Board of the Boys and Girls Club. He also is a member of the Minnesota State Bar Association.

Prior to joining Xcel Energy, Chandarana was a partner at the law firm of Briggs and Morgan where his practice focused on the energy industry. He represented utilities in commercial transactions involving generation interconnection agreements, power purchase agreements, and regulatory proceedings.

Chandarana received his B.A. in biology and business management from Washington University in St. Louis and his law degree from Washington University in St. Louis School of Law.

Authority or Reference	Title/Required Information	Section of Initial Filing
	MINNESOTA RULES	
Minn. Rule 7825.32	**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: (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.	Vols. 1 and 2A – 2E (see below for specific requirements and locations)
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 7825.33	**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 7825.36	**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. 2F 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 2016 test year.
Minn. Rule 7825.37	**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, 2D, and 2E
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;	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, Schedules 3 and 25 (Revenue Requirements) and Vol. 3, Section II, Tab 2.
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	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, Schedule 16 (Revenue Requirements) and Vol. 3, Section II, Tab 2.
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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, Schedule 16 (Revenue Requirements) and Vol. 3, Section II, Tab 2.

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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, Schedule 16 (Revenue Requirements) and Vol. 3, Section II, Tab 3, Part A.
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;	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, Schedule 16 (Revenue Requirements) and Vol. 3, Section II, Tab 3, Part B, Schedule B-1.
	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, Schedule B-2.
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. Note: the Company is a multi-jurisdictional utility.

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.

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 and compact disk provided with Vol. 3.
	(1) travel and lodging expenses; (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; (5) expenses for the ten highest paid officers and employees, including and separately itemizing all compensation and expense reimbursements; (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.	Vol. 3, Section IV, Part 2 EER Summary Report 1.

	(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 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.	Vol. 3, Section IV, Part 2 EER Summary Report 1.
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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 39-41; 55; 81-84 (Policy/MYRP Policy). Ian R. Benson, Exhibit___ (IRB-1), Vol. 2C, pages 54-99 and Schedule 2 (Transmission). Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2C, Page 40 (Distribution). Steven H. Mills, Exhibit___(SHM-1), Vol. 2C, Page 30 (Energy Supply). Timothy J. O'Connor, Exhibit___(TJO-1), Vol. 2C, page 55 (Nuclear Operations). David C. Harkness, Exhibit___(DCH-1), Vol. 2C, page 42 (Business Systems).

POLICY STATEMENTS		
Advertising	Statement that recovery is requested only for permitted advertisements. Description of advertisements for which recovery is requested. Sample advertisements for which recovery is requested.	Vol. 3, Section III, Tab 1. Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 71 and Schedule 15 (Revenue Requirements).
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. Evidence as to what organizations are gifted, their activities, and that no part of the contribution goes to benefit any private stockholder or individual. Itemized schedule showing amount, recipient and time of donations. Only 50% of qualified contributions shall be allowed as operating expenses.	Vol. 3, Section III, Tab 2. Vol. 4B, Section VIII, Tab A18. Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 77 (Revenue Requirements).
OrganizationDues	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. Testimony explaining the primary purpose of each organization.	Vol. 3, Section III, Tab 3. Vol. 4B, Section VIII, Tab A21. Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 74 and Schedule 16 (Revenue Requirements).
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. Other issues may include average or minimum cash balances required, depreciation, dividends and interest on debt	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 100 and Schedules 10 and 11 (Revenue Requirements).

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 3/1/1995	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.	Adam R. Dietenberger, Exhibit___(ARD-1), Vol. 2B, pages 3-9, 24-25 (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 –	The Company's Initial Filing includes the required information from the 587 docket. The Initial Filing also utilizes the 2015 Minnesota Legislature's amendments to §216B.16, subd. 19, as specified below.

Order, 6/19/13	A. Costs related to specific, clearly identified capital projects and	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 41-45 (Policy/MYRP Policy). Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, pages 7-15 (MYRP). Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2C, Pages 5-60 (Distribution). Steven H. Mills, Exhibit___(SHM-1), Vol. 2C, Pages 11-68 (Energy Supply).
	B. Appropriate non-capital costs.	David C. Harkness, Exhibit___(DCH-1), Vol. 2C, pages 10-112 (Business Systems). Ian R. Benson, Exhibit___ (IRB), Vol. 2C pages 26-34; 54-119 and Schedule 2 (Transmission). Timothy J. O'Connor, Exhibit___(TJO-1), Vol. 2C, pages 55-126 (Nuclear Operations).
	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 is demonstrated to be reasonable to do otherwise.	The Company's multiyear 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. The Company has also offered a five year plan. Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, page 69 (Policy/MYRP Policy).

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. The Company's three-year MYRP uses a constant ROE. The five-year MYRP option uses and indexed ROE. Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, page 54, 76 (Policy/MYRP Policy). James M. Coyne, Exhibit___(JMC-1), Vol. 2B, page 43 (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. Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, page 67 (Policy/MYRP Policy). Vol. 1, Interim Rate Petition Tab.

Order, 6/19/13		Minn. Stat. §216B.16, subd. 19 as amended in 2015 expressly allows for a utility to propose recovery of its forecasted rate base based on a formula, budget forecast or fixed escalation rate, individually or in combination. The Statute as amended further allows for recovery of operations and maintenance expenses based on an electricity-related price index or other formula. The Company's Initial Filing provides three years of forecasted capital and operations and maintenance expenses.
	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.	See Vols. 3 and 6. The Company's rate increase request utilizes this information in support of its request, while setting rates in 2016 based on the traditional test year approach, and in 2017 and 2018 based on a combination of forecasted (capital and capital-related O&M) and indexed (non-capital O&M). Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 41-45 (Policy/MYRP Policy). Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, pages 7-15 (MYRP). Vol. 2F, 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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, page 66 (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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 58-62 (Policy/MYRP Policy). Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 110 (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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 58-62 (Policy/MYRP Policy). Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 110 (Revenue Requirements).
	12. Commission will address new petitions for riders in deferred accounting on a case by case basis as they arise and will consider the status and objectives of the petition.	Not a completeness item.
	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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, page 60 (Policy/MYRP Policy). Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 94 (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. 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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 41-45 (Policy/MYRP Policy). Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, pages 7-15 (MYRP). Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 47-52 (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–	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 41-45 (Policy/MYRP Policy). Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, pages 7-15; 53-63 (MYRP).
Application Requirements	A. The specific capital projects for which the utility seeks to recover capital costs – and, where appropriate, non-capital costs – via the plan, B. The reason for the projects, C. The scope of the projects, D. The timing of the projects, E. The non-capital costs to be recovered via the plan and	Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2C, Pages 5-60 (Distribution). Steven H. Mills, Exhibit___(SHM-1), Vol. 2C, Pages 11-68 (Energy Supply). David C. Harkness, Exhibit___(DCH-1), Vol. 2C, pages 10-112 (Business Systems). Ian R. Benson, Exhibit___ (IRB), Vol. 2C pages 26-34; 54-119 and Schedule 2 (Transmission). Timothy J. O'Connor, Exhibit___(TJO-1), Vol. 2C, pages 55-126 (Nuclear Operations).
Application Requirements	F. The reason for seeking to recover the cost of the projects via a multiyear rate plan rather than via other means.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, page 27-35 (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.	Minn. Stat. §216B.16, subd. 19 as amended in 2015 expressly allows for a utility to propose recovery of its forecasted rate base based on a formula, budget forecast or fixed escalation rate, individually or in combination. The Statute as amended further allows for recovery of operations and maintenance expenses based on an electricity-related price index or other formula. Steven V. Huso, Exhibit___(SVH-1), Vol. 2E, pages 1-7 and Schedules 6 and 7 (Rate Design). Vol. 2F, 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 2, Tab 2.
Application Requirements	B. Rate base,	Vol. 3, Section 2, Tab 3.
Application Requirements	C. Operating income,	Vol. 3, Section 2, Tab 4.
Application Requirements	D. Rate of return and cost of capital schedules and	Vol. 3, Section 2, 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.	Vol. 3, Section 2.

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.	David Harkness, Exhibit___(DCH-1), Vol. 2C, pages 44-112 (Business Systems). Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2C, Pages 42-61 (Distribution). Steven H. Mills, Exhibit___(SHM-1), Vol. 2C, Pages 31-68 (Energy Supply). Ian R. Benson, Exhibit ___(IRB), Vol. 2C, pages. 26-99 and Schedule 2 (Transmission). Timothy J. O'Connor, Exhibit ___(TJO), Vol. 2C, pages 55-126 (Nuclear Operations).
Application Requirements	B. Depreciation lives related to capital additions in each year of the plan.	Lisa H. Perkett, Exhibit___(LHP-1), Vol. 2E, page 27-46 (Depreciation).
Application Requirements	C. Changes expected in the lives of all depreciable assets for two years after the plan.	Lisa H. Perkett, Exhibit___(LHP-1), Vol. 2E, page 40 (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.	Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, page 19 (MYRP). Lisa H.Perkett, Exhibit___(LHP-1), Vol 2E, pages 24-27 (Depreciation).
Application Requirements	E. A sales forecast.	Jannell E. Marks, Exhibit___(JEM-1), Vol. 2B, pages 15; 22-23; 63-64 and Schedules 4, 6 and 10 (Sales Forecast).

Application Requirements	F. A budget forecast.	The Budget Documentation provided in Volumes 3, 6A and 6B includes forecasts for the 2016 test year and the 2017 and 2018 Plan Years. Volume 3 also includes forecasts for 2019 and 2020. Company witness Greg Robinson addresses the process used to develop the budget forecasts. Gregory J. Robinson, Exhibit___(GJR-1), Vol. 2A, pages 11-26 (Budgeting).
Application Requirements	G. The utility's forecasting methodology.	Jannell E. Marks, Exhibit___(JEM-1), Vol. 2B, pages 32-40 and Schedules 7 and 8 (Sales Forecast). Gregory J. Robinson, Exhibit___(GJR-1), Vol. 2A, pgs. 3-27 (Budgeting).
Application Requirements	H. An analysis of the historical accuracy of the utility's short-term, medium-term and long-term forecasts.	Jannell E. Marks, Exhibit___(JEM-1), Vol. 2B, page 6-7 and Schedule 2 (Sales Forecast).

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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 35-47 (Policy/MYRP Policy). Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, pages15-40 (MYRP). Timothy J. O'Connor, Exhibit___(TJO-1), Vol 2C, pages 19-187 (Nuclear Operations). Ian Benson, Exhibit___(IRB-1), Vol. 2C, pages 27-34; 54-120 and Schedule 2 (Transmission). David C.Harkness, Exhibit___(DCH-1), Vol. 2C, pages 22-136 (Business Systems). Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2C, pages 5-82 (Distribution). Steven H. Mills, Exhibit___(SHM-1), Vol. 2C pages 7-103 (Energy Supply).
Application Requirements	B. A forecast of the changes in each cost category.	Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, pages 15-40 (MYRP).
Application Requirements	C. A forecast of any related offsetting revenues.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 52 (Policy/MYRP Policy). Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, page 10 (MYRP). Jannell E. Marks, Exhibit___(JEM-1), Vol. 2B, pages 13-28 Schedule 4 (Sales Forecast). Steven V. Huso, Exhibit___(SVH-1), Vol. 2E, pages 3-5 (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 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.	Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, pages 40-47; 49-53 (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. 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. B. Alternatively, the utility may explain that a new rate case under Minn. Stat. § 216B.16 is necessary to establish these rates.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 66 (Policy/MYRP Policy). Steven V. Huso, Exhibit___(SVH-1), Vol. 2E, pages 1-7 and Schedules 6 and 7 (Rate Design).
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, Interim Rate Petition 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: 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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, page 58 (Policy/MYRP Policy). Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 94-126 (Revenue Requirements).
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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, page58 (Policy/MYRP Policy). Vol. 1, Interim Rate Petition Tab. Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 94-99 (Revenue Requirements).
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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 2-3 (Policy/MYRP Policy). Vol. 1, Notice of Change in Rates and Interim Rate Petition 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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 44-45 (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.	Minn. Stat. §216B.16, subd. 19 as amended in 2015 expressly allows for recovery of a utility's forecasted rate base based on a formula, budget forecast, or fixed escalation rate, individually or in combination. The Company discusses this, in conjunction with the 587 Order language, in Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 44-45; 63 (Policy/MYRP Policy) and Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, pages 42-44 (MYRP).
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.	Vol. 1.
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 Rates Tab.
Customer Notice	26. The administrative law judge presiding over a case for a multiyear rate plan shall offer the opportunity for public comment.	Not a completeness item.
Customer Notice	27. All oral or written comments before the administrative law judge or the Commission shall become part of the case record.	Not a completeness item.
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.	Vol. 1, Interim Rate Petition Tab.

Compliance Filings	29. A utility applying for or operating under a multiyear rate plan shall do the following: 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.	The Company will provide all required compliance filings. Minn. Stat. §216B.16, subd. 19 as amended in 2015 expressly allows for recovery of a utility's forecasted rate base based on a formula, budget forecast, or fixed escalation rate, individually or in combination. The Company discusses this, in conjunction with the 587 Order language, in Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, page 49 (MYRP).
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.	Minn. Stat. §216B.16, subd. 19 as amended in 2015 expressly allows for recovery of a utility's forecasted rate base based on a formula, budget forecast, or fixed escalation rate, individually or in combination. The Company discusses this, in conjunction with the 587 Order language, in Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 44-45; 63 (Policy/MYRP Policy) and Charles R. Burdick, Exhibit (CRB-1), Vol. 2A, pages 42-44 (MYRP).

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).	Minn. Stat. §216B.16, subd. 19 as amended in 2015 expressly allows for recovery of a utility's forecasted rate base based on a formula, budget forecast, or fixed escalation rate, individually or in combination. The Company discusses this, in conjunction with the 587 Order language, in Aakash H. Chandarana, Exhibit___(AHC-1), Vol. 2A, pages 44-45; 63 (Policy/MYRP Policy) and Charles R. Burdick, Exhibit (CRB-1), Vol. 2A, pages 42-44 (MYRP).
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.	Charles R. Burdick, Exhibit (CRB-1), Vol. 2A, pages 49 (MYRP).
COMMISSION ORDERS IN XCEL ENERGY DOCKETS (E-002 or G-002)		
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.	Provided separately to agencies in accordance with the Order in E002/GR-92-1185 in Supplemental Budget Information Volume, Inflation Trend Analysis Tab.
	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;	This information is available for review at our office at 414 Nicollet Ave, Minneapolis, MN. Please contact Tim Searle at 612-330-6881.
	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, 6A and 6B. 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;	Vol. 3, Section II, Part 3, Tab C and Part 4, Tab D. Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, Schedules 10 and 11 (Revenue Requirements).
	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.
	e) The Company shall include month-by-month accounting of all transactions in the contingency funds;	Provided separately to agencies in Supplemental Budget Volume, Capital Substitution/ Contingent Fund Process and Reports Tab in accordance with the Order in E002/GR-92-1185.
	f) The Company shall provide a year-end summary report of project substitution with each contingency fund by project type and subject benefit.	Provided separately to agencies in Supplemental Budget Volume, Capital Substitution/ Contingent Fund Process and Reports Tab in accordance with the Order in E002/GR-92-1185.
	Advantage Service shall: - 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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 138 and Appendix A, pages 96-97 (Revenue Requirements). NSP Advantage Service now operates under the name HomeSmart from Xcel Energy®.
	In future rate case filings, NSP shall classify conservation, load management and economic development costs as capacity-related or energy-related based on a detailed analysis of the reasons the costs are incurred.	No longer applicable; see 13-868 rate case discussion below

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; 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.	Budget Documentation is included in Vols. 5, 6A and 6B of the Application. Also see Supplemental Budget Information Volume submitted to agencies which includes Inflation Trend Analysis, Budget Translation/ Analysis of Miscellaneous Expenses and Capital Substitution/ Contingent Fund Process and Reports.
AI-93-821	**Affiliated Interest Agreements with NRG**	
Order, 5/5/94	Purchase RDF. Show that these agreements have not resulted in any ratepayer subsidization of nonregulated activities.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 13; 111-113; 124 (Revenue Requirements).
M-93-1253	**Sale of Steam to Liberty Paper, Inc.**	
Order, 2/14/95	Costs of construction to be segregated from utility rate base, operating and maintenance expense to be recorded in nonutility operating accounts.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 42; 139 (Revenue Requirements).
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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 138 (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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page Appendix A, pages 5-64 (Revenue Requirements). Adam R. Dietenberger, Exhibit___(ARD-1), Vol. 2B, page 24 (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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 139 (Revenue Requirements).
AI-97-1190	**Affiliated Interest Agreements with NRG**	
Order, 10/17/99	Lease and agreement. Show that these agreements have not resulted in any ratepayer subsidization of nonregulated activities.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page Appendix A, pages 5-64 (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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 139 (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).	Adam R. Dietenberger, Exhibit___(ARD-1), Vol. 2B, page 22 (Cost Allocations).
CI-02-1346	**Financial Issues**	As discussed in 13-868, this docket no longer applies, given the sale of NRG and the passage of time.
CI-02-2188; CI-03-2002	**Withdrawal of Funds from VEBA Trust**	This issue was addressed in the 05-1428 rate case. The Company is drawing down the VEBA fund balance within the imposed limits and maintaining the minimum annual balances as required. The Company intends to omit this docket from future rate case completeness checklists.
Approved Agreement, 7/9/04	Demonstrate in a future rate case that the Agreement continues to be consistent with the public interest.	Brian J. Van Abel, Exhibit___(BVA-1), Vol. 2B, page 36 (Capital Structure).

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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 78-79 (Revenue Requirements). Brian J. Van Abel, Exhibit___(BVA-1), Vol. 2B, pages 7-8 (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.	Steven V. Huso, Exhibit___(SVH-1),Vol. 2E, pages11-14 (Rate Design).
M-04-1970	**MISO Cost Recovery**	
Order, 12/20/06	Each utility shall adopt the following accounting practices: A. Recording each transaction to separate sub-accounts 447 and 555 B. Recording to Account 555 on an aggregated basis any revenues and costs linked to Day 2 LMP, including generation offers to the market and load purchases used to serve native load customers, marginal loss compensations and marginal loss credits, if allowed through the fuel clause. C. Using net accounting for purchases and sales for owned generation facilities. D. Continuing to use Accounts 151 and 501 to record the fuel costs related to generation plants serving native load, the same way they are accounted for today. E. Continuing to use Account 447 to reflect the true costs of off-system wholesale sales, including related MISO	As explained in several rate cases, the Company's accounting of MISO costs and forecast for purposes of resetting the base cost of fuel and purchased energy reflect these requirements. See Base Cost of Energy filing submitted Nov 2, 2015 in Docket No. E002/MR-15-827. The Company intends to omit this docket from future rate case completeness checklists.
GR-05-1428	**2005 General Rate Case**	
Stipulation and Settlement Agreement – Asset and Non-Asset Based Wholesale Margins	The margins retained by the Company will be included in the Company's reported Minnesota jurisdiction electric revenues for purposes of annual reporting under Rule 7825.4900.	As explained in several rate cases, margins retained are included in the "Total Sales for Resale" and "Other" sections in the Company's annual electric jurisdiction report. See Page E-30, Lines B, of report filed May 1, 2015. The Company intends to omit this docket from future rate case completeness checklists.

PA-06-1662	**Edison Electric Spare Transformer Sharing Agreement**	
Order Approving, 4/4/07	NSP shall provide details of any sales or purchases of transformers made under the Spare Transformer Sharing Agreement in its next rate case.	There has been no triggering event and no sales or purchases of transformers; Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 138 (Revenue Requirements). Absent a triggering event, the Company intends to omit this docket from future rate case completeness checklists.
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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 134 and Non-Public Schedule 13 (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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 71 and Schedule 15 (Revenue Requirements).
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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 139 (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. 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	Forecasting data was pre-filed on October 2, 2015 in Docket No. E002/GR-15-826.

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 2, 2015 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 on a Compact Disk in the non-public package accompanying our submission.
	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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 134 and Schedule 14 (Revenue Requirements).
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. Identifies instances in which the Company relies on SFAS 71.
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, pages 24-30 (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.	See Vol. 3, compact disk, 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.	Adam R. Dietenberger, Exhibit___(ARD-1), Vol. 2B, page 13 (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.	Adam R. Dietenberger, Exhibit___(ARD-1), Vol. 2B, page 13-14 (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."	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 7; 55-57; 107-108 and Schedule 4 (Revenue Requirements). NOL reports have been filed on May 31, 2012 and May 31, 2013, June 2, 2014 and May 29, 2015 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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 7; 55-57; 107-108 and Schedule 4 (Revenue Requirements). NOL reports have been filed on May 31, 2012 and May 31, 2013, June 2, 2014 and May 29, 2015 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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 93-94 (Revenue Requirements). Vol. 4B, Section VIII, Tab A52. NOL reports have been filed on May 31, 2012 and May 31, 2013, June 2, 2014 and May 29, 2015 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 amounts estimated in Mr. Robinson's rebuttal pg. 17, Table 3.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 93-94 (Revenue Requirements). Vol. 4B, Section VIII, Tab A52. NOL reports have been filed on May 31, 2012 and May 31, 2013, June 2, 2014 and May 29, 2015 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.	Gary J. O'Hara, Exhibit ___(GJO-1), Vol. 2D, page 18 and Schedule 6 (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.	Gary J. O'Hara, Exhibit ___(GJO-1), Vol. 2D, Schedule 6 (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 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.	Gary J. O'Hara, Exhibit ___(GJO-1), Vol. 2D, pages 8-17 and Schedules 5A, 5B, 5C (Employee Expenses). Vol. 3 Section IV, Tab 2, Travel, Entertainment & Related Employee Expenses and compact disk provided with Vol. 3.
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: 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.	Gary J. O'Hara, Exhibit ___(GJO-1), Vol. 2D, pages 15-17; 23-28 (Employee Expenses). If requested, the complete audit reports will be made available to the Department and OAG.
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 and compact disk provided with Vol. 3.

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.	Gary J. O'Hara, Exhibit ___(GJO-1), Vol. 2D, pages 7-17 and Schedules 2, 3, 4 (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 October 28, 2015.
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.	Gary J. O'Hara, Exhibit ___(GJO-1), Vol. 2D, pages 20; 34 and Schedule 9 (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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 59-60 and Schedules 4, 14, 20, 21, 24, 26 (Revenue Requirements). NOL reports have been filed on May 31, 2012 and May 31, 2013, June 2, 2014 and May 29, 2015 in Docket No. E002/GR-10-971.
Order, 5/14/12 Order Point 24	The Company shall file its annual true-up report seeking a true-up and potential change to the Windsource rate on November 1, 2012 and each November 1 thereafter in the Windsource Program Docket No. E-002/M-01-1479.	The Company submitted its annual compliance report on October 30, 2015 Docket No. E002/M-01-1479.
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 the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case.	There were no costs of eligible projects excluded from the 2014 TCR. The 2015 TCR filing is pending in Docket No. E002/M-15-891.

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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 79-80 and Schedule 11 (Revenue Requirements).
Order, 9/3/13 Order Points 11-12	**Depreciation Reserves:** 11. Xcel shall amortize the difference between its actual and theoretical depreciation reserves for transmission, distribution and general assets over a period of eight years. 12. Xcel shall explore with the parties to its next rate case whether there should be any adjustments to depreciation reserves for Xcel's nuclear production assets.	These items have been superceded by the 5/8/15 Order in Docket No. E002/GR-13-868.
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 the same 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 October 2, 2015 in Docket No. E002/GR-15-826.
	b. A comparison to the forecast information in this docket and the Baseload Diversification Study filed on or around July 1, 2013;	Not applicable in this case.
	c. Large industrial customer account data in a format that allows interested parties to readily access historical data for all customers;	Large industrial customer account data was provided as Information Request No. 14 in the October 2, 2015 pre-filing of sales forecast information.
	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;	Raw weather data was addressed in Information Request No. 10 in the October 2, 2015 pre-filing of sales forecast information.
	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 in Steven V. Huso, Exhibit___(SVH-1), Vol. 2E, Schedule 3 (Rate Design).

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 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.	Steven V. Huso, Exhibit___(SVH-1), Vol 2E, pages 11-14 (Rate Design).
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. 2E, pages 1; 24; 42-43 (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. 2E, pages 1-2; 3-4; 17-19; 43 (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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 132-133 (Revenue Requirements).
Order, 9/3/13 Order Point 30	**AIP**: 30. Xcel shall evaluate the goals set for its annual incentive program to determine if they are too lenient or if they actually require stretching to meet; the Company shall file the results of the evaluation in its next rate case.	Incorporated into the 13-868 May 8, 2015 Order, Order Point 29.
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, page 68 (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, pages 23-24 and Schedule 3 Pension).
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 Order Point 47	**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).	Gregory J. Robinson, Exhibit___(GJR-1), Vol. 2A, pgs. 29, 32-36 (Budgeting) and Vol. 3. Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 128-129, and Appendix A (DOC-128) - live file located in the witness schedule CD (Revenue Requirements). Vol. 3, Section IV, Tab 1. Vol. 6, Supplemental Reports Tab.
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 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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 131 and Schedule 12 (Revenue Requirements).
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.	Steven H. Mills, Exhibit___(SHM-1), Vol. 2C, pages 79-96 and Schedules 9 and 10 (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.	Lisa H. Perkett, Exhibit___(LHP-1), Vol. 2E, page 13 (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: 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) 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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 129 and Schedule 5 (Revenue Requirements).
GR-13-868	**2013 Electric Rate Case**	
Issues List, pg. 38	**Wholesale Billing Revenues**: The Company noted that it anticipates receiving a refund from Alliant for transmission expense paid, which will also include $561,616 accounted for in 2014 Other Revenue. The Company proposed to include this revenue in the three-year historical average of Other Revenues in a future rate case.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 128 (Revenue Requirements).
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 2E, pages 1-2; 21-23 (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 2E, pages 1-2; 24-26 and Schedule 10 (CCOSS).

Order, 5/8/15 Order Point 3	**Monticello.** 3. Xcel shall exclude the 2014 depreciation expense and return on the Monticello EPU from the 2014 test year based on a 50% allocation to the EPU. Xcel is authorized to recover the EPU costs in the 2015 Step, but if the EPU is not in service by January 1, 2015, the Company shall refund any excess amounts collected through the refund mechanism for the multiyear rate plan.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 79 (Revenue Requirements).
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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 79-80 (Revenue Requirements). Lisa H. Perkett, Exhibit___(LHP-1), Vol. 2E, page 57-58 (Depreciation). We also made a compliance filing in Docket No. E002/GR-13-868 on May 15, 2015 per PUC Order dated May 8, 2015.
Order, 5/8/15 Order Point 5	**Monticello.** 5. Xcel is authorized to recover $950,000 in Monticello prudency-review costs with a two-year amortization period. If the Company does not file its next rate within this two-year period, it shall return any over-recovery to customers when it files its next rate case.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 128 and Schedule 20 (Revenue Requirements).
Order, 5/8/15 Order Point 6	**Pension.** 6. The Company shall use 5.05% (a five-year average of discount rates determined under Financial Accounting Standard 87) as the approved discount rate to determine its XES Plan pension costs for ratemaking purposes.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, page 38 (Pension).
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, page 39 (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. The Company shall provide a detailed compliance filing which explains the calculated amount within ten days of the Commission's decision.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, page 85 and Schedule 14, which is a copy of the compliance filing submitted on April 6, 2015 (Pension).
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.	George R. Tyson, II, Exhibit___(GET-1), Vol. 2E (Pension Investments (Tyson)). R. Evan Inglis, Exhibit___(REI-1), Vol. 2E (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.	George R. Tyson, II, Exhibit___(GET-1), Vol. 2E (Pension Investments (Tyson)). R. Evan Inglis, Exhibit___(REI-1), Vol. 2E (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, pages 65, 75, 77 & 100 and Schedules 11 & 12 (Pension). Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, pages 80-81 and Schedule 2 (Revenue Requirements). Vol. 4B Test Year Workpapers, Section VIII. Adjustments, Tab A-14
	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.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, pages 79-92 and Schedule15 (Pension). Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 81 (Revenue Requirements).

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, pages 70-71 (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, pages 68-69 and Schedule 13 (Pension).
Order, 5/8/15 Order Point 16	**Retiree Benefits.** 16. In the initial filing of its next electric rate case, the Company shall: a. discuss the cost components of the postretirement benefits plans cost (other than pensions) affecting Minnesota rates, particularly the drivers of the amortization of net gain/loss amount and the reasons this component amount has varied since its last rate case (Docket No. E-002/GR-13-868); and b. provide the report of future years' actuarial cost projections of the postretirement benefits (other than pensions), clearly identifying the assumptions and measurement point used to develop these projections.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, pages 70-75 and Schedule 11 (Pension).
Order, 5/8/15 Order Point 17	**Healthcare.** 17. In its next rate case the Company shall provide historical active health care costs since 2011 for each calendar year, including both the per-book amount and the actual claims expense. The Company shall also provide information detailing the annual year-end Incurred But Not Reported (IBNR) accruals and subsequent reversals.	Richard R. Schrubbe, Exhibit___(RRS-1), Vol. 2D, pages 92-94 (Pension).
Order, 5/8/15 Order Point 20	20. The Company may include the unamortized nuclear-refueling-outage costs in rate base and earn the overall allowed rate of return on that balance.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 134 and Schedule 14 (Revenue Requirements).

Order, 5/8/15 Order Point 23	23. The Company shall notify the Commission and report and capture potential cost reductions or other forms of compensation that may result from contract changes or contractors' failure to meet contract terms for either the Pleasant Valley or the Border Wind projects. Such cost reductions and compensation payments will be subject to Commission review for potential credits or refunds to ratepayers.	These projects are not completed, so there is nothing to report at this time.
Order, 5/8/15 Order Point 28	**Aviation.** 28. The Commission adopts ALJ Finding 564 modified to read as follows: 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."	We are not seeking cost recovery of aviation costs in this case. Gary J. O'Hara, Exhibit___(GJO-1), Vol. 2D, page 28 (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-1), Vol 2D, pages 59-63 (Comp and Benefits). David C. Harkness, Exhibit___(DCH-1), Vol. 2C, pages 139-141 (Business Systems). Michael C. Gersack, Exhibit___(MCG-1), Vol. 2E, page 37 (Customer Care/Bad Debt). Kelly A. Bloch, Exhibit___(KAB-1), Vol. 2C, page 97 (Distribution). Gregory J. Robinson, Exhibit___(GJR-1), Vol. 2A, pages. 36-40 (Budgeting). Steven H. Mills, Exhibit___(SHM-1), Schedule 16, pages 132-136, Vol. 2C. (Energy Supply). Timothy J. O'Connor, Exhibit___(TJO-1), Vol. 2C, pages 189-195 and Schedule 11 (Nuclear Operations). Gary J. O'Hara, Exhibit___(GJO-1), Vol. 2D, pages 32-38 (Employee Expenses). Ian R. Benson, Exhibit___(IRB-1), Vol. 2C, pages 153-157 (Transmission).
Order, 5/8/15 Order Point 30	**Transmission.** 30. In its next electric rate case, the Company shall: a. present a new key performance indicator (KPI) for transmission O&M costs; b. provide a comparison study of its transmission O&M costs by using appropriate peer companies, along with justification for why certain utilities were included or excluded; and c. propose a new cost control KPI at the vice-presidential level for overall transmission costs.	Ian R. Benson, Exhibit___(IRB-1), Vol. 2C, pages 149-153 (Transmission).

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. 2E, pages 1-2; 25-26 and Schedule 10 (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. 2E, pages 1-8; 15-16; 43 and Schedule 2 (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. 2E, pages 1-2; 29-40 and Schedule 11 (CCOSS).
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; 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.	a. to c: Michael A. Peppin, Exhibit___(MAP-1), Vol. 2E, pages 1-3; 15-18 and Schedule 9 (CCOSS). d: Steven V. Huso, Exhibit___(SVH-1), Vol. 2E,pages 7; 17-18 and Schedules 4-7 (Rate Design).

8/31/15 Order Order Point 15	In future multiyear rate cases, regarding the issue of the passage of time: 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 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.	Aakash H. Chandarana, Exhibit___(AHC-1), Vol .2A, pages 50-51 (Policy/MYRP Policy). Charles R. Burdick, Exhibit___(CRB-1), Vol. 2A, pages 19-22 (MYRP). Lisa H. Perkett, Exhibit___(LHP-1), Vol. 2E, pages 24-27 and Schedule 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.	Anne E. Heuer, Exhibit___(AEH-1), Vol. 2A, page 135 (Revenue Requirements).
M-14-761	**2016-2018 Triennial Nuclear Plant Decommissioning Accrual**	
10/5/15 Order Order Point 9	Within 120 days of the date of this order or in its next rate case, Xcel shall make a filing to enable the Commission to determine the appropriate method for crediting any future Department of Energy Settlement proceeds resulting from the Settlement extension.	Lisa H. Perkett, Exhibit___(LHP-1), Vol. 2E, page 49 (Depreciation).