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Direct Testimony and Schedules
Timothy J. O'Connor

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-19-564
Exhibit___(TJO-1)

Nuclear Operations

November 1, 2019

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Nuclear Fuel Process & Costs	Schedule 3
Non-Outage O&M Expense Summary	Schedule 4
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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Timothy J. O'Connor. I am the Chief Nuclear Officer for Northern States Power Company, a Minnesota Corporation (NSPM or the Company) and an operating company of Xcel Energy Inc. (Xcel Energy). I am responsible for all nuclear activities in Minnesota at the Monticello and Prairie Island Nuclear Generating Plants.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have 34 years of experience in the nuclear industry, including a diverse background in operations, maintenance, and engineering at both boiling and pressurized water reactors. Before joining Xcel Energy in 2007, I held a number of positions with increasing responsibility at Constellation Energy Group's Nine Mile Point station in New York, Public Service Enterprise Group's (PSEG) Hope Creek and Salem plants, and Exelon's LaSalle, Dresden, and Zion plants. My resume is attached as Exhibit___(TJO-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. First, I provide an overview of our Nuclear Operations business area. Next, I discuss the performance of our nuclear fleet and steps we continue to take to improve performance and operate more efficiently. I then provide an update on current industry trends and issues. I also present and support the Company's multi-year rate plan (MYRP) capital additions, present and support the O&M budgets related to the Nuclear Operations function, and address the conclusions and recommendations contained in the November 1, 2018 Final Report of Global Energy & Water Consulting LLC (GEWC) to the Department of Commerce Regarding Prairie Island (the Final GEWC Report).

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY AND AN OVERVIEW OF NUCLEAR OPERATION'S PLANS FOR THE NEXT THREE YEARS.

A. This case, and our pending 2019-2034 Upper Midwest Resource Plan, present important questions for the Minnesota Public Utilities Commission with respect to the future of Xcel Energy's nuclear generation and its role in a carbon-free energy future. For almost 50 years, our Monticello Nuclear Generating Plant (Monticello) and Prairie Island Nuclear Generating Plant Units 1 and 2 (Prairie Island) have provided 1700 MW of reliable, safe, and carbon-free energy to our customers.

Together, these plants comprise more than half of our existing carbon-free generation and one-third of our total generation; and they serve more than one million customer homes. Our reliance on these plants avoids the emission of 7 million tons of carbon dioxide each year, which is equivalent to removing 1.5 million cars from the road (or more than 20 percent of all registered vehicles in Minnesota as of 2016). The continued role of nuclear on our system is, therefore, critical to ensuring that we continue to make progress in reducing our carbon emissions toward our corporate goal of achieving an 80 percent reduction in carbon emissions by 2030, as well as our long-term goal of 100 percent carbon-free energy by 2050.

Meanwhile, our nuclear fleet adds important diversity to our generation portfolio and provides a hedge against not only gas price volatility but also the uncertainty of technological development, future renewable pricing, and the future of solar capacity values. It is also a critical piece of our reliability requirement, as it is not a fuel limited resource, is not subject to pipeline limitations during the winter season, and has a strong operating history during cold (and hot) weather events. Lastly, it is important to note the state, community, and employment benefits associated with our nuclear fleet, which employs approximately 1400 staff in and around the Monticello and Red Wing communities, which translates into an estimated 4200 additional jobs across Minnesota.

While we view nuclear power as a central piece of our generation fleet, we recognize that maintaining a fleet of nuclear power plants also presents unique requirements, such as specialized safety needs and a very high level of regulatory oversight. Safety is the Company's first priority for nuclear generation, and is an ever-present consideration in any investment we make. We also understand, though, that the future of our nuclear fleet depends on our ability to deliver performance at a reasonable cost, and we have undertaken substantial efforts to adopt an innovative approach plant operations—all with the aim of "bending the cost curve." As discussed in our last rate case, the Company has worked closely with the Institute of Nuclear Power Operations (INPO) and the Nuclear Regulatory Commission (NRC) to improve equipment and human performance. The Company has also worked with its industry partners, most notably in connection with the Nuclear Energy Institute's (NEI) "Delivering the Nuclear Promise" initiative (DNP). These efforts have ultimately brought our plants into top quartile performance. In fact, by every measure, our nuclear fleet has never operated on a more consistent, efficient, and safe basis.

To maintain this level of performance, we must continue to address the reliability of our aging equipment. The NRC's aging management program requires monitoring and planning for upgrades to refurbish equipment to "like new" condition or replace it. We discuss some of these investments later in my testimony.

My Direct Testimony outlines both the benefits of nuclear energy generally and the specific performance of our nuclear fleet since the Company's last rate case. After discussing these issues, and the purpose and mission of Xcel Energy's Nuclear Operations Business Unit (Nuclear Operations or Nuclear), I discuss our current capital investment plan for the coming years; why the level of capital we propose to invest in our nuclear plants is reasonable, and the kinds of projects that we plan to undertake. I illustrate in detail that we are making the right kind of investments in our nuclear facilities; balancing the need for safety and our obligation to manage to regulatory requirements with customers' interests in cost-effective, carbon-free energy.

Next, I discuss in detail the level of non-outage and then outage operating and maintenance (O&M) expenses that we expect to incur in the coming years, and again explain why it is necessary and wise to support this level of O&M costs. I address our overall maintenance plans and our upcoming planned outages, supporting the need for those efforts and the basis for our cost estimates to complete them. Finally, I respond to the recommendations in the Final GEWC Report.

Overall, the Company views nuclear generation as a cornerstone not only of our overall fleet, but also of our industry-leading carbon reduction goals. We have undertaken significant efforts to drive industry-leading performance while reducing the costs of our nuclear operations—all while keeping safety as our first priority. As discussed in my testimony, our anticipated capital and O&M levels are reasonable and, as shown in the Electric Utility Cost Group (EUCG) data in Exhibit___(TJO-1), Schedule 5, reflect that both of the Company's nuclear sites are among the lowest cost nuclear facilities in the nation. The information provided in this testimony strongly supports rate recovery in this case at the levels requested.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. I first describe our current nuclear operations and our fleet performance since our last general rate case. I then describe our capital additions impacting 2020, 2021, and 2022, followed by a description of our O&M expenses for those years. My testimony is organized as follows:

- *Section II* – Nuclear Operations Overview and Fleet Performance
- *Section III* – Capital Investments
- *Section IV* – Non-Outage O&M Budgets
- *Section V* – Planned Outage O&M Budgets
- *Section VI* – Response to the Final Report of GEWC
- *Section VII* – Conclusion

II. NUCLEAR OPERATIONS OVERVIEW AND FLEET PERFORMANCE

A. Overview and Value Proposition

Q. PLEASE DESCRIBE XCEL ENERGY'S CORE NUCLEAR OPERATIONS.

A. Xcel Energy owns and operates three nuclear units; one unit at Monticello, Minnesota, and two units at Prairie Island in Welch, Minnesota.

Monticello is a single-unit boiling water reactor rated for gross output at 671 MW, and was originally licensed by the NRC in 1970. The NRC approved a renewed license for the facility in 2006, allowing the plant to operate through 2030. As discussed in our pending 2019-2034 Upper Midwest Resource Plan, the Company intends to seek a license extension to allow the plant to operate an additional 10 years, to 2040.

Prairie Island is a two-unit pressurized water reactor, with each unit rated at 550 MW gross output capacity. The NRC licensed Prairie Island's two units in 1973 and 1974, respectively. The initial operating licenses were set to expire in 2013 and 2014. In 2011, the NRC approved renewed licenses for Prairie Island Units 1 and 2, extending their operating lives until 2033 and 2034.

Q. PLEASE DESCRIBE THE TOP PRIORITIES OF THE NUCLEAR ORGANIZATION.

A. Our top priority is operating at the industry's highest standards for safety and reliability. However, we also recognize that we must operate our plants at a competitive cost, and we have been on a journey of continuous improvement to drive strong performance and reduce cost—all while maintaining a focus on safety and reliability. Our mission in Nuclear is to foster a learning environment that promotes safe operations, continually raises operational performance to standards of excellence, promotes accountability for strong financial stewardship, and demonstrates leadership within the nuclear industry and the communities we serve.

Q. WHAT IS THE VALUE PROPOSITION FOR NUCLEAR FROM A CUSTOMER PERSPECTIVE?

A. Nuclear offers more than 1700 megawatts of cost-effective, carbon-free, generating capacity, and it powers over one million households in our service territory. In 2018, Nuclear provided almost 30 percent of the generation used by the NSP system in the upper Midwest, and nearly 23 percent of the State's electricity—*all with no greenhouse gas emissions*. See Exhibit___(TJO-1), Schedule 2, which includes the latest NEI Fact Sheet on Minnesota and Nuclear Energy. The value proposition for Nuclear has several components.

Reliable Carbon-Free Energy – Nuclear is a critical generation source for NSP customers. Over the past three years, Monticello achieved an average capacity factor of 96.5 percent, with a record-setting 99.3 percent in 2018. Prairie Island achieved a combined average capacity factor of over 90 percent over the past three years, including 100 percent capacity factor for Unit 2 in 2018. No other generation source is as reliable as Nuclear, as nuclear plants are designed to run at this output level, while other resource options are not. Nuclear generation provides the constant output that is an important and necessary complement to the large amounts of intermittent, renewable generation on our system.

Clean Energy – Nuclear is a critical component of the Company's carbon reduction goals. Nuclear energy produces more than 55 percent of Minnesota's emission-free electricity and is unique in that it can do so virtually around the clock; see Schedule 2. As a result, it is estimated that in 2018, Minnesota's nuclear facilities prevented the emission of 15.3 thousand tons of sulfur dioxide, 10.7 thousand tons of nitrogen oxides, and 13.6 million metric tons of carbon dioxide. See Schedule 2, which includes NEI's summary of emissions avoided in 2018 by the U.S. nuclear industry. The role of nuclear generation is further heightened as more and more coal generation comes offline.

Cost-effective Resource – Now more than ever, our nuclear fleet is delivering this carbon-free energy at a competitive cost. In fact, our production costs per MWh are at their lowest point in over a decade. And at the same time, we have achieved all-time-high capacity factors at both plants, which further reduce our cost per MWh. The impact of these cost reductions can be seen in the economic modeling for our 2019 Integrated Resource Plan, in which license extensions of all three nuclear units produced the greatest economic benefits.

Fuel Diversity – The Company's nuclear power plants provide the Company and its customers a hedge against changes in resource availability, fossil fuel prices, and future emissions regulations. Our nuclear units use a steadily available fuel at a consistent cost per MWh. The fuel assemblies in each nuclear unit's reactor contain the equivalent energy of approximately six million tons of coal used to produce electricity.

Jobs and Economic Development – Xcel Energy currently has about 1400 employees working in or directly supporting our Nuclear business area, but the economic impact of our fleet goes well beyond that. In its report "*The Impact of Xcel Energy's Nuclear Fleet on the Minnesota Economy*," NEI estimates that in 2016, "Xcel Energy's nuclear facilities were estimated to contribute $595 million to Minnesota's gross state product (GSP). . . " In addition, the report finds that "…for every dollar of output from Xcel Energy's nuclear operations, the state economy produces $1.98." The Company's nuclear fleet also generates substantial tax revenue for the state, contributing about "$33 million in state and local taxes annually." see Schedule 2.

B. Nuclear Fleet Performance

Q. BEFORE DISCUSSING RESULTS, PLEASE REVIEW NUCLEAR OPERATIONS' STRATEGIC FOCUS AREAS, AS COMMUNICATED IN THE LAST RATE CASE.

A. In our last rate case, we discussed the following three strategic focus areas that would shape Nuclear Operations' work during the term of the MYRP:

- *Safe operations* - with the goal of meeting the NRC's expectation for public safety by complying with our operating license, ensuring plant security and adequately planning for emergencies, safely conducting dry fuel storage, and anticipating what safety issues might be coming. Our goal was to achieve Column 1 status, without "greater than green" findings[1] or cross-cutting issues raised by the NRC and without significant operating events.
- *Reliability* - targeted at delivering high capacity factors, meeting system generation output expectations and optimizing refueling outages.

[1] See Exhibit___(TJO-1), Schedule 9, which includes a summary of the NRC's Reactor Oversight Process and the color coding used to designate findings from inspections and performance reporting.

- *Cost optimization and higher performance standards* - through optimizing fuel cycles, building connections with the Utility Services Alliance, and using strategic sourcing focusing on performance accountability, and implement organizational best practices.

Q. WHAT RESULTS HAVE BEEN ACHIEVED WITH RESPECT TO THESE STRATEGIES?

A. We delivered. In focusing on these strategies, we have undertaken substantial efforts to change the way we approach plant operations and deliver benefits to our customers. Working with third-party consultants with expertise in both nuclear operations and general cost containment and efficiency strategies, and with the INPO and NEI, we have achieved industry-leading results, not only in the performance of our nuclear plants, but also in managing the costs we are investing to achieve that performance. Indeed, we are the only nuclear fleet in the industry that has all units in Exemplary Status at INPO, all units in NRC Column 1 Status with all green performance indicators, and all units with no NRC Safety Culture Concerns. The end result is that our nuclear plants have never operated on a more consistent, efficient, and safe basis. Since the Company's last rate case, we have achieved the following results:

- *Safe operations* – Both Monticello and Prairie Island are Column 1 plants with all green performance indicators. Additionally, during the refueling outage in 2017 at Prairie Island, we achieved the best industrial safety record and lowest occupational radiation exposure in plant history. Finally, both Prairie Island and Monticello have received the Governor's annual safety award for several years running.
- *Reliability* – The investments we have made in our plants over the past six years have paid off. Monticello has operated at an average capacity factor

of 96.5 percent over the past three years, including a record-setting 99.3 percent in 2018. Similarly, Prairie Island achieved a combined average capacity factor of more than 90 percent over the past three years, including a 100 percent capacity factor for Unit 2 in 2018. Contributing to these capacity factors was improved performance during plant refueling outages, which were completed on time and on budget.

For example, in 2017, Prairie Island's Unit 2 achieved a 37-day refueling outage; which is that unit's shortest refueling duration in 10 years. We have also experienced some of the longest runs of uninterrupted operation in the history of our nuclear fleet, including a record-setting 499 days at Prairie Island Unit 1 in 2016-2017, and a recent run of 640 days at Prairie Island Unit 2 prior to its planned refueling coast down on August 22, 2019. In fact, Prairie Island Unit 2 is currently on the third longest run in plant history. Notably, our nuclear fleet also operated at a 100 percent capacity factor from January through April of 2018, and again in early 2019 during the Polar Vortex, before Monticello began its planned coast down in advance of its April refueling outage.

Similarly, the summer months of 2018 and 2019 saw the nuclear fleet operating at full power during peak summer loads. In short, our nuclear fleet has never performed better.

- *Cost optimization and higher performance standards* – Importantly, we have achieved these safety and operational results without increasing our production costs. In fact, both O&M and total production costs at our nuclear plants have decreased significantly in recent years. Total O&M for our nuclear fleet went down by $7 million between 2015 and 2016. It then decreased again by another $26 million in 2017, and decreased yet again in 2018 by another $8 million. In terms of production costs (fuel plus O&M) per MWh, we achieved reductions of more than 20 percent between 2015 and 2018, resulting in our lowest production costs per MWh in over a decade.[2] Specifically, our fleet average nuclear production costs have gone from $37.86 per MWh in 2015 down to $29.44 in 2018 (Prairie Island has gone from $37.08 down to $28.53, and Monticello has gone from $39.11 down to $30.91).

We have also completed a long-term re-analysis of our capital budgets for both Prairie Island and Monticello, and we have made significant changes to our capital forecast. The updates to our forecast reflect years of work by numerous Company employees, leadership, and external consultants, as well as a recognition that we had to re-envision our approach to nuclear operations if our plants were going to remain competitive. The forecasts are based on a detailed, long-range capital budgeting process that was undertaken following our 2015 Resource Plan; I discuss the results of these efforts in Section III of my testimony.

C. Industry Developments, Trends and Challenges

Q. PLEASE DESCRIBE RECENT NUCLEAR INDUSTRY DEVELOPMENTS THAT IMPACT NUCLEAR'S OPERATIONS, COSTS AND RESOURCE REQUIREMENTS.

A. We consider two recent industry developments to be especially impactful for purposes of this rate case: the NRC's increasing efforts to advance risk-

[2] These reductions in our nuclear production costs are directionally consistent with the nuclear industry as a whole, which has achieved a more modest average reduction of approximately $5/MWh since 2012.

informed licensing and regulation, and the success of industry group collaborations. I will discuss each of these in more detail.

NRC's Risk-Informed Regulation & Licensing –Since 2017, the NRC has been working to advance risk-informed regulation and licensing. Risk-informed regulation is defined by the NRC as "[a]n approach to regulation taken by the NRC, which incorporates an assessment of safety significance or relative risk. This approach ensures that the regulatory burden imposed by an individual regulation or process is appropriate to its importance in protecting the health and safety of the public and the environment." This approach uses insights from probabilistic risk assessments (PRAs), along with other engineering insights, to arrive at regulatory strategies. The NRC is also engaging in increased numbers of risk-informed license application reviews (LARs). The goal is to achieve shorter review times. In 2016, the NRC approved 40 risk-informed LARs, and in 2017, it approved 45 risk-informed LARs. From a practical perspective, this allows plants to meet the same high standards of safety and compliance while also allowing some flexibility as to the means by which that level of safety and compliance is achieved. The risk-informed approach leads to cost savings and increased safety by allowing nuclear operators to direct investment to where it will have the greatest positive impact on performance and safety, based on consideration of that plant's characteristics. The agency has renewed its focus on advancing these efforts and risk-informed regulation will likely have substantial impact during the period covered by this rate case.

Industry Collaboration – Beginning in 2015, NEI, its member companies, and third-party experts began the "Delivering the Nuclear Promise" (DNP initiative.) In its early stages, this initiative concentrated on three areas: (1) maintaining a focus on safety and reliability; (2) improving the efficiency of operating nuclear plants; and (3) ensuring monetary recognition of nuclear energy's value. Beginning in 2018, the focus of this initiative shifted to an effort to develop, review, and approve efficiency-boosting ideas on an industry-wide basis. This stage of the initiative involves recommending opportunities with the most significant savings opportunities to industry leadership, aligning the industry on the way to move forward on those ideas, and approving efficiency bulletins outlining those ideas. Leadership of this initiative regularly collaborates with representatives from the Electric Power Research Institute (EPRI) and the Boiling Water Reactors Operating Group (BWR) to drive innovation. The initiative anticipates issuing several highly significant efficiency bulletins brought forward each year. The goal is to allow plant owners and personnel to focus on critical efficiency enhancements with the least amount of administrative burden, allowing plants to operate more efficiently while retaining safety and reliability.

Q. PLEASE DESCRIBE THE COMPANY'S RISK-INFORMED PROJECTS AND LICENSING EFFORTS.

A. The Company's risk-informed projects are intended to reduce Nuclear's operating costs through reduction in maintenance costs and purchasing costs, along with introducing more flexible operating requirements. The Company is engaged in three primary risk-informed projects: (1) the Surveillance Frequency Control Program (SFCP); (2) the Risk-Informed Engineering Program (RIEP); and (3) the Risk-Informed Completion Times (RICT) program. The SFCP allows the licensee the ability to extend the intervals for appropriate surveillances, directly reducing the costs of the maintenance. The

RIEP program allows for purchasing alternative parts for low risk components and also allows for less frequent testing and maintenance of these components. The RICT allows for deferential treatment of select maintenance activities that might otherwise result in expensive plant shutdown activities. The Company has designated risk-informed decision-making as a core competency, and once all of these efforts have been implemented, the Company's nuclear plants will be in the top 20 percent of the industry in terms of risk-informed program implementation.

In July of 2019, the Company's LAR for Prairie Island, which sought to revise the NFPA 805 Project License Conditions to a process based on risk versus a deterministic approach, was approved by the NRC. The License Amendment incorporated new PRA modeling into the Prairie Island Fire Model. Incorporating the new methodologies allowed for the fire model risk to be revised, and resulted in the removal of five modifications that were part of the original NFPA 805 project scope to be removed. Removal of these modifications reduced the amount of capital spend for the NFPA 805 project by approximately $10 million. The investment cost for the model revisions and license submittal, by contrast, was under $0.4 million.

Q. PLEASE EXPLAIN HOW THE COMPANY HAS IMPLEMENTED EFFICIENCY MEASURES DEVELOPED BY THE INDUSTRY.

A. The Company consistently reviews and, where practical, implements industry efficiency innovations. Our most significant recent adoption of an industry efficiency innovation is our implementation of the "Transform the Maintaining the Plant Organization" efficiency opportunity as described in NEI Efficiency Bulletin 17-23. This model promotes working within the design of existing plants to achieve operational and safety goals rather than making modifications to plants. This leads to greater operational efficiencies while lowering O&M and capital spend. I was the lead industry representative on that initiative, and we are being benchmarked by other utilities on our work in this area. Our implementation of this model is one of the factors that led us to achieving INPO 1 (exemplary) status.

Q. WHAT OTHER GENERAL TRENDS ARE YOU SEEING IN THE INDUSTRY?

A. The industry has been faced with a number of trends that present both opportunities and challenges for the Company. One of the most significant trends we have seen in the utility industry generally is an increased focus on carbon reduction and the transition away from coal generation. Xcel Energy has been an industry leader on carbon reduction, and its goal of achieving 100-percent, carbon-free energy by 2050 has been adopted not only by other utilities across the nation but also by the State of Minnesota. Nuclear's around-the-clock carbon-free energy is a critical component of this shared goal.

Industry challenges also exist. While the Company's nuclear fleet is performing at a historically high level, the Company remains concerned about issues related to permanent fuel storage and labor resource challenges given the combination of an aging industry workforce nationwide, competitive demand for experienced nuclear personnel, and the uncertainty of long-term public policy commitments to nuclear energy in the U.S.

Q. THE COMPANY WAS RECENTLY AWARDED A DEPARTMENT OF ENERGY (DOE) GRANT TO EXPLORE HYDROGEN PRODUCTION. CAN YOU DESCRIBE THIS PROJECT?

A. Earlier, I discussed our efforts to increase the flexibility of our plants to allow the integration of additional renewables into our system. The incorporation of hydrogen production fits into that strategy, because it would allow us to operate the plant at full output while also lowering power output. With respect to the DOE grant of $1.3 million, the Company has partnered with two additional utilities and the Idaho National Lab to explore the potential economics of producing hydrogen from a light water reactor. Our role in the project is to study the potential marketplace for hydrogen, and the technical feasibility of doing so at one of our nuclear facilities. We are exploring two types of hydrogen production with this project—low temperature electrolysis, which uses electricity to change water into hydrogen and oxygen; and high temperature electrolysis, which adds steam from the nuclear plant to help improve the efficiency of the process compared to low temperature electrolysis.

Q. WHAT IS THE COMPANY'S FINANCIAL CONTRIBUTION TO THE PROJECT?

A. At this point, our contribution is limited to approximately $0.3 million of staff time and resources.

Q. WHAT ARE THE POTENTIAL USES FOR HYDROGEN PRODUCED AT PRAIRIE ISLAND?

A. Prairie Island itself uses a certain amount of hydrogen as part of its normal operations, so "in-house" production at the plant would eliminate our need to purchase hydrogen from a third party. Hydrogen also has the potential to transform the transportation industry, as vehicles transition away from fossil fuels. Additionally, the Company's fossil fleet—particularly its combined cycle combustion turbines—could someday be converted to using hydrogen as a fuel source, enabling those plant to generate carbon-free energy.

Q. IS THERE A POTENTIAL FOR THE COMPANY TO DO ADDITIONAL WORK IN THIS AREA IN THE FUTURE?

A. Yes. We are proposing a pilot to DOE for implementation of a high temperature electrolysis project at one of our nuclear plants.

Q. WHAT ISSUES DO YOU BELIEVE ARE MOST CRITICAL FOR THE NUCLEAR ORGANIZATION TO ADDRESS IN THE NEXT FEW YEARS?

A. We need to continue to work with the DOE to resolve long-term fuel storage and disposal issues at a reasonable cost.[3] We also need to ensure we maintain a stable, qualified workforce given the industry's staffing challenges. Additionally, as part of moving towards a carbon-free generation fleet by 2050, we are working on increasing our operational flexibility so that we can ramp down our plants during periods of high transmission congestion and low prices, such as times when abundant renewable resources are available on our system. This includes our efforts to demonstrate our units' ability to participate in the MISO Day Ahead market, which will help with the Company's efforts to integrate its continuing renewable additions.

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[3] The costs of dry cask storage are the subject of a settlement with the DOE, which resulted from DOE's breach of the Standard Contract established in 1998 for the disposal of spent nuclear fuel. Under that settlement agreement, DOE is obligated to reimburse the Company for costs incurred due to DOE's failure to begin removing spent nuclear fuel from commercial power plant site nationwide beginning in January 1998. Pursuant to various Commission Orders, these DOE reimbursement dollars are typically refunded to customers by means of a base rate refund, though the Company has occasionally been ordered to apply the DOE reimbursement dollars to the Nuclear Decommissioning Trust (NDT).

Currently, we have moved beyond the pilot stage, with Monticello and Prairie Island 1 currently in the market and Prairie Island 2 slated to enter the market after completion of its Fall 2019 refueling outage. Finally, during the period of this rate case, we will begin the work on relicensing our Monticello plant. Although the Monticello license will not expire until 2030, relicensing is a lengthy process. The NRC is currently considering subsequent relicensing of three plants as part of a pilot program intended to pave the way for efficient processing of relicensing applications in the 2020s. The Company will comply with the five-year "safe harbor" requirement by submitting its application in advance of 2025.

D. Key Nuclear Strategies for the Long Term

Q. HOW DOES NUCLEAR PROPOSE TO ADDRESS THE KEY ISSUES AND TRENDS DISCUSSED ABOVE?

A. We have already begun this work and are seeing the results. As I discussed earlier, the Company's investments in its nuclear plants over the past six years have factored into our industry-leading performance. As a result of this performance, the Company's nuclear operation is becoming a benchmark for other nuclear utilities. This success allows us to focus on issues such as providing leadership in identifying a permanent fuel storage solution, working on pipeline issues related to workforce, and improving the Company's ability to integrate additional renewable resources into its system by increasing operational flexibility.

Q. PLEASE DISCUSS THE COMPANY'S EFFORTS WITH REGARD TO STORAGE OF SPENT FUEL.

A. With the Yucca Mountain proposal on hold, and no apparent alternative permanent storage facility, we continue to rely on interim dry cask storage for the near term. And while continued investment in dry cask storage remains a necessity, at the same time, the Company is working with other industry leaders on developing alternative interim and permanent solution to address the storage of spent nuclear fuel. For example, in May of this year, I testified before the United States Senate Committee on Environment and Public Works on this topic, addressing the ongoing need for a permanent repository for nuclear fuel and in support of developing interim consolidated storage sites. We will continue to participate in discussions on this issue and actively support both the development of a permanent repository and consolidated interim storage sites.

Q. PLEASE DISCUSS THE COMPANY'S EFFORTS WITH RESPECT TO WORKFORCE PLANNING.

A. Through the use of Nuclear's retention program, we have created robust internal succession plans and have achieved significant depth in our staffing. Maintaining a qualified and engaged workforce, however, remains an ongoing priority, and one that all high-performing nuclear organizations view as critical to maintenance of the industry's high standards of performance and safety. As a result, the Company must continue to create staffing pipelines that sustain the supply of qualified licensed-required positions such as operators, chemistry technicians and radiation protection technicians. Since the extended time for training to meet regulatory qualification expectations for these roles can be up to two years, these pipelines have to be in active hiring mode continuously each year. While capital and operational improvements have allowed for some reduction in headcount at Prairie Island, a continuing pipeline is needed to replace experienced employees that depart either due to retirement or attrition.

Q. HOW DOES THIS RATE REVIEW RELATE TO THE STRATEGIC INITIATIVES AND TRENDS OUTLINED ABOVE?

A. In order to sustain our high level of performance and continue our leadership in the areas of risk-informed programming, the Company must continue to make capital investments as well as incur O&M expenses to support the ongoing operation, safety, and reliability of the Company's nuclear power plants. Nuclear is at a point where the majority of significant modifications needed to operate both plants until the end of their licenses have been made, and the Company's focus is now on maintaining the plants and implementing risk-informed programs.

Our culture is rooted in the idea of continuous improvement, and nuclear will continue to focus on efficient ways to deliver high levels of performance and safety while also lowering costs to customers.

III. CAPITAL INVESTMENTS

A. Overview and Trends

Q. FOR THIS CASE, DO THE NUCLEAR CAPITAL INVESTMENTS FOR THE 2020 TO 2022 TIME PERIOD CONTINUE TO BE PRESENTED IN THE CAPITAL BUDGET GROUPINGS THAT YOU DISCUSSED IN THE COMPANY'S LAST CASE?

A. Yes. For long-range planning purposes, Nuclear continues to group projects around a common theme to assist in the analysis of budget plans, assignment of project management resources, and benchmarking across the industry. The Company now uses the term "Major Category" to describe these groups, and I will use that terminology in the remainder of this Testimony. These major categories enable the application of common practices among similar projects. The groupings (excluding fuel loads) can be described as follows:

- *Dry Cask Storage* is work associated with on-site dry spent fuel storage and loading campaigns, including the Independent Spent Fuel Storage Installation (ISFSI) and related NRC-mandated aging management programs given the lack of a permanent federal repository for spent fuel.
- *Mandated Compliance* includes regulatory, security, and license commitment activities required by Federal or state regulators (normally the NRC), including industry commitments made to the NRC, as well as projects that require NRC approval.
- *Reliability* activities improve equipment reliability or reduce maintenance activities, and include life cycle management programs and projects.
- *Improvements* include activities that improve system and equipment performance and operation (for example: digital upgrades), and can reduce O&M costs.
- *Facilities & Other* includes facility work such as building improvements, roof replacements, road repairs and general plant additions such as small tools and equipment.

Q. AND FOR THE YEARS 2016-2018, CAN YOU PROVIDE A SUMMARY OF HOW YOUR INVESTMENTS FELL INTO THOSE MAJOR CATEGORIES?

A. Yes. Table 1 below provides a summary of Nuclear's capital additions by major category (in millions) for the years 2016-2018.

Table 1

NSPM Electric Utility Nuclear	2016	2017	2018
Dry Cask Storage	$19.8	$13.5	$68.4
Mandated Compliance	40.0	41.2	78.1
Reliability	64.8	79.3	138.0
Improvements	5.5	3.2	6.9
Facilities & Other	4.3	0.5	0.8
Subtotal – Projects	134.4	137.7	292.2
Nuclear Fuel	67.7	148.8	82.1
Total Nuclear Additions	$202.1	$286.5	$374.3

Q. CAN YOU FURTHER DISCUSS THESE CATEGORIES AND WHAT MAY DRIVE INVESTMENTS IN THEM IN ANY GIVEN YEAR?

A. Each of the nuclear major categories now in use has a strategic driver that can change the need for investment year by year.

- The Dry Cask Storage category addresses the need to safely store old/used fuel on-site until a federal repository is established.
- Mandated Compliance is driven by the requirements of the NRC or other regulators as a condition of maintaining our license to operate the plants.
- Reliability is driven by the fact that the Company's nuclear plants are over 45 years old and require ongoing capital investment to maintain reliable operation through equipment upgrades and replacement to address aging and obsolescence issues.

- Improvement enables us to capture opportunities for improved output or operational performance and efficiency, which can provide a payback for the investment through higher output or lower operating cost.
- Facilities and Other includes ongoing activities to maintain plant building and properties, and provide small tools and equipment to support normal plant operation.
- Fuel is necessary to operate the reactors and provide the steam to generate power.

Although we have reduced our capital forecast relative to earlier forecasts such as the 2015 resource plan, we recognize that the capital investment made to date and required in the future for our nuclear plants is substantial. However, we believe that investment is warranted given the value of safe, carbon-free, reliable, generation that these plants deliver, providing the power for more than one million customer homes. More importantly, capital investments cannot be viewed in isolation, as the level of capital investments may impact O&M expenditures and vice versa. Only a full review of both capital investments and O&M expenses can provide an accurate view of the overall cost of any business or business area, including Nuclear Operations. Our long-term capital investment plan balances regulatory requirements, equipment risk, funding capabilities, and customer benefit and cost.

Q. WHAT ACTIVITY HAS OCCURRED WITH RESPECT TO THESE MAJOR CATEGORIES SO FAR IN 2019?

A. As of July 2019, Nuclear forecasted to add projects in 2019 in the amount of $1.4 million in Dry Cask Storage, $3.8 million in Mandated Compliance, $77.2

million in the Reliability Grouping, $11.1 million in Improvements, and $0.9 million in Facilities & Other. Also, Nuclear was forecasted to add $156.3 million of fuel in connection with refuelings at Prairie Island Unit 2 and Monticello.

Q. LOOKING AHEAD, WHAT ARE YOUR CAPITAL FORECASTS FOR 2020-2022 BY MAJOR CATEGORY?

A. Table 2 below provides a summary of Nuclear's budgeted capital additions for the years 2020-2022.

Table 2
Nuclear Capital Additions 2020-2022
Including AFUDC ($ in millions)

NSPM Electric Utility Nuclear	2020 Budget	2021 Budget	2022 Budget
Dry Cask Storage	$14.1	$14.70	$29.2
Mandated Compliance	10.7	4.6	1.0
Reliability	28.9	65.5	62.0
Improvements	18.1	10.1	0.7
Facilities & Other	1.6	0.6	1.3
Subtotal – Projects	73.5	95.4	94.3
Nuclear Fuel	84.5	152.7	74.6
Total Nuclear Additions	$158.0	$248.1	$168.8

Q. WHAT KEY PROJECTS WILL YOU BE INVESTING IN OVER THE TIME PERIOD 2020-2022?

A. We will be investing in a number of projects that I discuss below. Fuel is always a key capital investment in any year and for the 2020 to 2022 multi-year rate plan time period accounts for more than 50 percent of the total capital additions for Nuclear. Beyond fuel and dry cask storage, we intend to invest in a security system upgrade at Prairie Island, cooling tower rebuilds at Prairie Island and cooling tower upgrades at Monticello and process control systems replacements at Prairie Island.

Q. WHAT OTHER PROJECTS DO YOU EXPECT TO DRIVE YOUR INVESTMENTS OVER THESE YEARS?

A. Overall, we anticipate future investments in projects in each of the capital budget categories. Table 3 below summarizes nuclear capital expenditures by major category (excluding AFUDC) for the test years 2020-2022 in comparison to actuals for 2016-2018 and the forecast for 2019.

Table 3

Actual 2016-2018 and Forecasted 2019-2022 Capital Expenditures
Excluding AFUDC - $ in millions

NSPM Electric Utility Nuclear	2016 Actual	2017 Actual	2018 Actual	2019 Fcst	2020 Budget	2021 Budget	2022 Budget
Dry Cask Storage	$13.6	$10.2	$26.4	$11.0	$24.1	$23.3	$13.9
Mandated Compliance	43.8	41.3	21.7	4.1	7.4	13.7	16.7
Reliability	82.8	82.3	109.6	45.6	36.8	64.9	73.4
Improvements	2.0	4.5	10.7	14.7	18.7	15.5	14.2
Facilities & Other	3.2	0.7	0.5	0.9	1.8	0.9	3.9
Subtotal – Projects	$145.4	$139.0	$168.9	$76.3	$88.8	$118.3	$122.1
Nuclear Fuel	114.6	113.6	62.7	125.7	54.5	102.4	88.5
Total Nuclear Cap Ex	$260.2	$252.6	$231.6	$202.0	$143.3	$220.7	$210.6

These expenditures accumulate as projects progress, AFUDC is added, and the total costs are placed in service as capital additions, as discussed in the next section of my testimony. As illustrated in Table 3 above, Nuclear's capital expenditures are expected to trend significantly downward relative to the 2016-2018 time period, and are expected to remain within an approximately $76-120 million range (excluding fuel) for each year between 2019 and 2022.

Q. ARE THERE ANY TRENDS YOU'D LIKE TO HIGHLIGHT THAT ARE DEMONSTRATED BY TABLE 3?

A. Yes. Nuclear capital expenditures in the Mandated Compliance category show a significant decline after 2018. This is primarily driven by the completion of Fukushima-related requirements and Emergency Diesel Generator (EDG) Tornado Missile Protection work at both sites, and the wind down of the NFPA 805 Fire Model and Modification work at Prairie Island.

Q. PLEASE EXPLAIN THE COMPANY'S NUCLEAR CAPITAL ADDITIONS.

A. Table 4 below summarizes nuclear capital additions by major category for the years 2020-2022 in comparison to actuals for 2016-2018 and the forecast for 2019. The additions in Table 4 include both capital expenditures and accrued AFUDC.

Table 4

Actual 2016-2018 and Forecasted 2019-2022 Capital Plant Additions Including AFUDC - $ in millions							
NSPM Electric Utility Nuclear	**2016 Actual**	**2017 Actual**	**2018 Actual**	**2019 Fcst**	**2020 Budget**	**2021 Budget**	**2022 Budget**
Dry Cask Storage	$19.8	$13.5	$68.4	$1.4	$14.1	$14.7	$29.2
Mandated Compliance	40.0	41.2	78.1	3.8	10.7	4.6	1.0
Reliability	64.8	79.3	138.0	77.2	28.9	65.5	62.0
Improvements	5.5	3.2	6.9	11.1	18.1	10.1	0.7
Facilities & Other	4.3	0.5	0.8	0.9	1.7	0.6	1.3
Subtotal – Projects	$134.4	$137.7	$292.2	$94.4	$73.5	$95.4	$94.2
Nuclear Fuel	67.7	148.8	82.1	156.3	84.5	152.7	74.6
Total Nuclear Additions	$202.1	$286.5	$374.3	$250.7	$158.0	$248.1	$168.8

While capital additions are directly affected by our capital expenditures, the capital additions trend may not mirror the capital expenditure trend. The capital expenditure trend reflects the progress of the project's spend through the months, whereas the capital addition trend reflects the total cost at the conclusion of the construction or implementation process when the asset is placed in service. The difference between capital expenditures and capital additions reflects the varying lengths of time required to complete different projects.

Q. WHAT KINDS OF CHANGES COULD OCCUR THAT MAY LEAD TO A RE-PRIORITIZATION OF YOUR CAPITAL INVESTMENT NEEDS AND CHANGE THE PERCENTAGES THAT YOU INVEST IN EACH MAJOR CATEGORY?

A. There are several reasons why we may need to reprioritize capital investments in any given year or over the course of several years.

Management does its best to predict the progression in which projects are completed, which ones will be completed in each year, and how much in additions will flow into rate base for the test year. However, given new regulatory requirements, emergent equipment issues, changing business priorities, and constraints on corporate funding availability, it is difficult to plan precisely in advance which individual projects will be completed in each future year. In addition, complications in engineering and design, challenges in vendor bidding or performance, and constraints for resource scheduling can cause the timing and cost of individual project additions to change in any year from that assumed in the budget. That said, the 2020 to 2022 capital budgets are our current best estimate of the capital work needed in the coming years. Even if the individual projects making up the budgets may change slightly, these budgets remain reasonably representative of the capital investment needed for Nuclear Operations in 2020 to 2022.

Q. WHY IS THE ABILITY TO CHANGE THE MIX/MAKEUP OF MAJOR CATEGORIES FOR NUCLEAR IMPORTANT TO THE COMPANY AND YOUR CUSTOMERS?

A. At any given time, it is the Company's responsibility to ensure we are investing in our Nuclear generation wisely on behalf of customers. It would not be prudent to invest in a project that is no longer needed, or to delay a project that becomes essential, simply to align with a capital plan that was developed before circumstances changed. This is particularly true as safety, mandated compliance, or plant reliability needs change over time.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW CHANGING CIRCUMSTANCES IMPACT CAPITAL INVESTMENT DECISIONS?

A. Yes. In 2018 Prairie Island was scheduled complete a project to replace several valves on the Cooling Water Header which had degraded and could not be relied upon to provide an adequate isolation boundary. Through additional analysis, we were able to determine a more cost-effective maintenance strategy to address the valve degradation that did not necessitate valve replacement. Because we did not need to expend capital funds on valve replacement, we were able to reallocate those funds to complete the EEQ Computer Model project, which resolved several NRC Non-Cited Violations related to the Equipment Qualification Program. This project also reduced future O&M expense and capital equipment replacements by providing refined analysis methods that extended the environmentally-qualified life of several key pieces of plant equipment.

Q. SHOULD CUSTOMERS OR THE COMMISSION BE CONCERNED THAT SPECIFIC CAPITAL PROJECT PLANS EVOLVE?

A. No. It is in our customers' and regulators' interests that the Company applies the funding available to the risk-significant projects prioritized from most to least risky. We make changes to the specific projects we implement during the course of a year to address emerging issues or perform like-kind replacements for previously planned projects. In this way, we better serve our business and our customers' most pressing needs in a cost-effective way. When the need arises to accelerate a project, we assess the situation to make sure we are doing so for the right reasons and in a prudent manner. Similarly, we assess potential project delays or cancellations to make sure we are still meeting business and customer needs in a reasonable way.

While we may sometimes have to shuffle the list of projects to accomplish that, this is a normal part of managing our business.

Q. EVEN IF YOUR INVESTMENT GROUPING PERCENTAGES CHANGE FROM THE CURRENT FORECAST, WILL NUCLEAR STILL MANAGE ITS OVERALL CAPITAL INVESTMENTS TO ITS OVERALL BUDGET?

A. Yes. We are committed to meeting our performance goals while staying within our overall capital budget.

Q. SO WHAT DO YOU CONCLUDE ABOUT NUCLEAR'S 2020-2022 CAPITAL INVESTMENT FORECASTS?

A. I conclude that our capital forecasts represent an accurate and reasonable picture of our necessary investments planned over these years. Therefore, these forecasts can be relied on to set just and reasonable rates for our customers.

B. Capital Budget and Investment Planning Process

1. Reasonableness of Overall Capital Budget

Q. PLEASE MAKE THE BUSINESS CASE FOR THE NUCLEAR CAPITAL PROGRAM.

A. Nuclear generation provides the Company's customers with carbon-free generation to combine with sources like gas and renewable sources like wind and solar. Our nuclear fleet's high capacity base production allows renewable resources – which cannot be expected to run consistently given their intermittent nature – to be optimized for customers through a diverse portfolio of competitive, carbon-free energy.

Operating our nuclear plants requires capital investments to meet the needs for fuel management, comply with NRC license requirements, and replace/upgrade equipment so that the units can function reliably in normal operations, deal appropriately with any unusual situations, and provide adequate safety protections. The cost of these investments is estimated, benchmarked for industry comparability, and leveraged though vendor procurement sourcing, with the objective to deliver the best value to customers.

In addition, to gain an accurate picture of the overall costs of any business, capital investments must be viewed together with O&M expenses, since timely and prudent capital investment can lead to lower O&M expenses going forward. For example, the Security Physical Upgrades Phases I & II projects at Monticello directly reduced the number of Security Officers required onsite, which reduced the plant's O&M costs. The Security Physical Upgrades Phase I, completed in 2017, had an annual cost savings of $1.1 million. The Security Physical Upgrades Phase II, completed in 2018, has an annual cost savings of $2.5 million.

Q. HOW DOES THE NUCLEAR AREA ESTABLISH A REASONABLE CAPITAL BUDGET FOR EACH YEAR?

A. Nuclear's capital investment requirements are identified and established through development of a long-term asset strategy. Due to the complexity of executing projects for an operating nuclear power plant, they are typically identified many years in advance. Our plans are subdivided into the categories discussed previously to help understand the priorities. In addition, we look at capital needs through the end of each unit's current operating license (or in the case of Monticello, also considering a planned license extension). This long-term view helps ensure that the overall planning and timing of our capital investments support safe, compliant, and reliable operation. Each year we re-evaluate our capital needs during the annual budget cycle.

The appropriate annual capital budget for Nuclear is based on a partnership between corporate management of overall finances and the business needs we identify for our constituents. Company witness Mr. Gregory J. Robinson explains how the Company establishes overall business area capital spending guidelines and budgets based on financing availability, specific needs of business areas, and overall needs of the Company.

Nuclear employs a "bottom-up" approach to capital budget development, meaning that we look at the needs and potential needs of our plant and then assess how much it would cost to address each of them. We listen to our nuclear employees – engineers, operators and maintenance staff – and strive to address the issues they raise by getting their input and plotting a course of action. The decision-making on capital investments needs is undertaken by the Nuclear executive management team, in collaboration with Xcel Energy governance processes, and ultimately approved by the Board of Directors of the Company.

As noted previously, our capital budgeting process evaluates and balances requirements, risks, opportunities, and funding capabilities. It includes four major elements:

- Identification of NRC license requirements, including regulations and inspection findings;

- Evaluation of equipment and plant health issues to meet business plan operational goals (such as safety system availability, generation capacity, forced loss rate, fuel reliability and chemistry control);
- Prioritization of potential capital projects based on risk and urgency considering factors such as age of equipment, operating risk and need, and regulatory risks; and
- Consideration of the relative funding available from the corporation given the needs and requirements of all business units and stakeholders.

A number of governance and oversight functions exist to support these capital budget development efforts at both the Nuclear department and corporate Xcel Energy level. They include:

- Technical Review Board (TRB) at each plant site;
- Plant Health Committee (PHC) at each plant site;
- Long Range Planning (LRP) process;
- Long Range Planning Committee;
- Central Project Review Group (PRG) with members from each plant site and the fleet; and
- Executive PRG for the nuclear fleet (for projects in excess of $3 million);

Ultimately, these processes appropriately balance the needs of our nuclear plants with the need for cost-effective electric generation for our customers, arriving at a reasonable budget for Nuclear in each year. I explain this governance and oversight process in more detail below.

2. Nuclear Capital Planning Process & Governance

Q. PLEASE DESCRIBE THE PROCESS TO EVALUATE NRC LICENSE REQUIREMENTS, AND POTENTIAL CAPITAL PROJECTS NEEDED TO ADDRESS THEM.

A. NRC license requirements are entered into the Corrective Action Process (CAP) and evaluated regularly by the Engineering and Regulatory Affairs functions. CAP is an NRC-mandated license compliance program. The evaluations include not only plant license requirements but also the NRC's new rules and regulations, Regulatory Issue Summaries, Task Interface Agreements, and other communications. The CAP program is quite extensive and complicated. About one-half of our engineering resources are dedicated to the CAP program, reviewing safety licensing documentation so the plant can operate in compliance with NRC requirements.

If deviations from NRC requirements are identified, and capital funding is required to resolve the deviation, then a project request is initiated using Nuclear's "Project Review and Approval Process" procedures. The request is also added to the long-range plan using Nuclear's LRP process within our Project Review and Approval Process procedures, as I discuss later.

Q. PLEASE DESCRIBE THE PROCESS TO EVALUATE EQUIPMENT AND PLANT HEALTH ISSUES, AND POTENTIAL CAPITAL PROJECTS NEEDED TO ADDRESS THEM.

A. Equipment and plant health issues are also entered into the CAP, which establishes how we document and track resolution of conditions deviating from desired plant performance levels. The CAP ensures that deviations from performance expectations are promptly identified, evaluated, and corrected through actions commensurate with safety significance, and verified as a closed issue.

The PHC is the cornerstone for addressing equipment reliability issues. The PHC is an industry best practice developed from INPO's excellence standards. The PHC's primary focus is to understand the site's existing equipment reliability issues, prioritize these issues and ensure that the site resources are aligned to support resolution consistent with their priority. The process ties together material condition evaluations, work identification and approval, and the business planning process. One output of the PHC is providing inputs to the LRP, which outlines current and future project expenditures as I describe later.

PHC inputs are forwarded to the PRG for consideration. The PHC recommends projects to PRG, which then ensures that capital projects are properly ranked and thus re-evaluates priorities of previously authorized capital projects, as required.

Q. PLEASE DESCRIBE THE PROCESS TO PRIORITIZE POTENTIAL CAPITAL PROJECTS IDENTIFIED, BASED ON RISK AND URGENCY.

A. Capital projects are prioritized in accordance with Nuclear's *Prioritization Guidelines*, which provide guidance for ranking projects based on various criteria for risk and urgency. The prioritization guideline is integrated into the planning, implementation, and budgeting processes for capital projects. For the current year, the prioritization guideline works to manage capital spend to the approved budgets, to evaluate the impact of emergent issues, and to communicate these impacts to the affected process owner. For future years, the procedure works to formulate project budgets and to identify potential adjustments to optimize whenever possible. The PHC validates[4] or assigns the prioritization ranking for capital projects in accordance with Prioritization Guidelines. As I noted earlier, the PRG reviews the risk and urgency rankings of all recommended projects for the nuclear fleet, and continually re-evaluates priorities of previously authorized projects, as required, to allocate (and re-allocate) available capital funding for the nuclear fleet.

Q. PLEASE DESCRIBE THE PROCESS TO CONSIDER AND ASSIGN FUNDING TO NUCLEAR CAPITAL PROJECTS BASED ON CORPORATE NEEDS, REQUIREMENTS, AND FINANCING CAPABILITY.

A. The LRP establishes a multi-year baseline project plan for the plant based on the plant's strategy and prioritization of work through the end of current license. A phased funding approach is used to develop project cost estimates and further classify the projects on the LRP as Study, Design, or Implementation Phase expenditures. A project must be identified on the LRP to be included in the annual capital budget. During creation of the annual budget, the PRG uses the LRP to determine which capital projects will be proposed for a given year. The PRG ensures proposed projects are subjected to effective business evaluations and management review at key decision points prior to committing significant resources and ensures projects meet corporate financial objectives. At the time of the annual budget creation, the fleet-wide Executive Project Review Group (EPRG) reviews and approves the LRP for the combined fleet for the five-year budget period, which is then

[4] Each plant has a Technical Review Board (TRB) which reviews proposed modifications to improve plant health, identify best alternatives, establish issue priority ranking per Prioritization Guidelines and report the results of the TRB to the plant's PHC.

submitted for corporate review and approval by Xcel Energy through the Investment Review Committee and/or Finance Council.

Ultimately, the collective process operates as an effective decision making function of the Company's leadership team. The PHC determines the appropriate technical solution for issues raised; the PRG assesses risk and determines the appropriate cost alternatives for the issues, and the EPRG looks at broader business area and Company risk and makes a final decision to approve capital spending (subject to corporate funding constraints). This process creates an independent view from each site for oversight of safety and cost.

Q. PLEASE DESCRIBE THE PROCESS TO BUILD THE BUDGETS FOR SPECIFIC CAPITAL PROJECTS, IN-SERVICE DATES, AND AMOUNTS OF CAPITAL ADDITIONS BY YEAR.

A. We have a well-defined, tactical process for capital budgeting, along with strategic oversight and decision-making accountability.

From a process standpoint, project requests that are approved by the PHC are assigned a Project Manager. The Project Manager develops or revises the initial project estimate as described in *Project Management Institute Manual* procedures. Cost estimating is based on industry standards[5] included in PRG procedures. These standards provide for varying levels of estimates as a project proceeds. through the three-phase funding approach, comprised of

[5] AACE International, formerly the Association for the Advancement of Cost Engineering, prepares professional practice guides (PPG) for engineers such as PPG#7, *Cost Engineering in the Utility Industries*. *See* ACEE INTERNATIONAL, www.aacei.org (last visited Oct. 21, 2015); the Project Management Institute (PMI) provides guidance on project management procedures. *See* PROJECT MANAGEMENT INSTITUTE, www.pmi.org (last visited Oct. 25, 2019).

study, design and implementation phases. The PRG reviews the initial cost estimate and approves or rejects the project for LRP addition. The LRP includes the annual project cash flows.

Project Management procedures align with industry practices including the development of a Project Management Plan. The Project Management Plan preparation should start in time to permit initial approval by the milestone date identified in the standard project milestones table of Project Management procedures. The standard project milestones are used as an input to establish the in-service dates. The Project Management Plan defines how the project will be implemented, monitored, controlled and closed. Included in the Project Management Plan are Cost and Funding, as well as an Implementation Strategy. The Cost and Funding section of the Project Management Plan estimates costs and resource impacts; including: design implementation, materials, internal resources, procedure updates, simulator updates, disposal costs, NERC compliance requirements, and NRC fees. The Implementation Strategy section of the Plan provides what will be required to accomplish the project scope and achieve the desired deliverable. The Implementation Strategy should include all preparations and restraints, and identified resources, vendors, and other experts.

Project planning also uses benchmarking and performance contracts with vendors to more effectively predict and control project costs. Throughout the nuclear industry we frequently use benchmarking with other utilities to compare scope, align on technical aspects of project design and execution, and better identify and mitigate risks. Our benchmarking of project costs within the nuclear industry is typically limited to higher level order of magnitude figures due to the sensitivity and confidentiality of detailed financial information. However, this higher level benchmarking has provided valuable insights in aligning our Fukushima program costs with what other companies were experiencing with similar work. We also utilized this type of benchmarking on the Reactor Coolant Pump replacement at Prairie Island in 2016. Internal to Xcel Energy, we have engaged in detailed cost benchmarking for projects like our Cooling Tower Refurbishment Projects at both Monticello and Prairie Island. We have also been able to drive better cost predictability through the negotiation of long-term construction and maintenance agreements. These agreements have allowed us to negotiate better rates, implement cost incentives and penalties for contracted work, and more effectively leverage resources to avoid in-processing costs. We also work with our vendors on larger projects like the Electric Generator Replacement at Prairie Island to build in performance milestones and liquidated damages to hold them accountable for the quality, cost, and timeliness of their work. After the capital expenditure budgets by project are prepared and expected in-service dates are established, all of the projects are accumulated by month and year, and the aggregate capital budgets are reviewed by the Nuclear management team in the governance process discussed previously. The combination of project-specific reviews and approvals, and overall alignment with strategic decision making, provides accountability for a reasonable level of capital investment for Nuclear.

Q. HOW DOES THIS PROCESS TIE BACK TO THE OVERALL COMPANY BUDGET?

A. Once individual capital projects are developed using the processes and procedures I have described, they are rolled up to total budgeted capital costs by major categories. Often, the desired initial fleet capital budget request exceeds the Company's spending guidelines, which then requires review meetings with functional managers, directors, and vice presidents to assess the requested budget and determine the appropriate course of action given funding availability. These leaders evaluate the risks of options available and make judgments on the course of action to take.

Because this happens throughout the Company for all business areas, a higher or lower percentage of the Company's overall resources may be allocated to Nuclear in any given year, depending on the priority of needs throughout the Company. Once the balancing and budgeting process is completed, Nuclear may be able to maintain the list of projects "as is," or may need to adjust the capital investment plan within the established budget thresholds.

Q. DO YOU BELIEVE THAT NUCLEAR'S PROCESS RESULTS IN CAPITAL BUDGETS FOR 2020-2022 THAT REPRESENT A REASONABLE LEVEL OF COSTS FOR CUSTOMERS TO INCUR?

A. Yes. This process results in a reasonable budget that is representative of the capital investment needed to meet Nuclear's prioritized requirements and plant needs for the test year. In each year, Nuclear capital additions are reasonable and necessary to maintain the stability, safety, reliability, and compliance of our nuclear plants in service of our customers. The capital budgets for this period are reasonable given the life cycle status of our plants (in particular Prairie Island), based on industry comparisons with costs of similar projects, and considering inputs of independent validations of the need for these projects.

3. *Capital Budget Updates & Oversight of Emergent Work*

Q. IS IT POSSIBLE TO PLAN PRECISELY FOR ALL INDIVIDUAL PROJECTS THAT WILL NEED TO BE DONE IN FUTURE YEARS?

A. Not entirely. As I discussed previously, the capital budgeting process identifies a list of potential projects that must be prioritized based on risk and urgency. This list is continually updated, and given the fact that the budget is prepared six to eighteen months prior to the budget period, priorities can certainly change in that timeframe. For example, many projects have long lead times for engineering, design, scoping, resource appropriation and scheduling, and consequently the timing of the final work can shift between the budget preparation and project completion.

In addition, new priorities can arise, from emerging regulatory requirements (like the Fukushima program earlier this decade) or equipment issues, such as the identification of a turbine oil pump and motor skid that was degrading. In that situation, an emergent project was initiated to correct the degraded condition by replacing the affected equipment to meet current industry standards. Another emergent project was initiated when a heat exchanger that supports a site emergency diesel generator showed signs of degradation. These changing priorities require Nuclear to continually reassess the relative ranking of risk and urgency for all projects, and new priorities can rank ahead of previously identified ones. When total corporate funding capabilities are limited, which they usually are, that can mean that some projects are delayed to make room for the new priority projects that are identified after the budget was prepared. Accordingly, while the total capital spend for Nuclear may stay close to constant, the individual projects funded in a particular year can change over time as new priorities arise.

Q. HOW DOES NUCLEAR MANAGE ITS OVERALL CAPITAL BUDGET WHEN PRIORITIES CHANGE?

A. LRP procedures establish the process to systematically plan for capital expenditures for long-term operation of the Xcel Energy Nuclear plants. It supports making operation, resource allocation, and risk management decisions to maximize fleet value to stakeholders, while maintaining and improving safety and reliability for the public and plant staff. The LRP process works in conjunction with the PRG and Prioritization Guideline procedures. Periodically, it may be necessary to reallocate and reforecast capital expenditures, as unforeseen problems encountered are difficult to fix, and often require final implementations that differ from initial conceptual plans. When new projects arise, the site PRG will initially perform the reallocation of plant prioritization and will update the capital forecast with the new funding information. Before the funds are authorized to reallocate capital spend, however, the Site Vice President and the Vice President, Nuclear Capital Projects must concur with the PRG recommendations and approve the revised capital forecast. The sites are accountable to the Nuclear leadership team via EPRG, and the Nuclear leadership team is accountable to the Company's Financial Council. These accountabilities effectively reallocate resources as part of managing our business.

Q. WHAT DOES NUCLEAR DO TO MANAGE CAPITAL COSTS WHEN THEY EXCEED ORIGINAL BUDGETS, OR WHEN UNPLANNED PROJECTS BECOME CRITICAL PATH?

A. We have a process that tracks changes in individual projects, but also provides overall governance with accountability to total capital investments made.

From a process standpoint, when changes are identified that will impact project budget, scope, schedule or quality, the resolution and approval are documented on Project Impact Notice/Project Scope Change Request form in accordance with Project Management Manual procedures. If the change is significant, PRG procedures require that a change to the project funding authorization be prepared and submitted to PRG for approval. If at any time during a project's execution the total cost is projected to exceed an authorization threshold requiring additional corporate review and approval, then the responsible Project Manager shall ensure the project is presented to Nuclear EPRG, or Xcel Energy corporate Investment Review Committee, or Finance Council for approval as governed by corporate policies/procedures. Project Impact Notice/Project Scope Change requests that are attributable to a vendor are analyzed against the vendor's contract and the vendor will be held accountable to said contract requirements.

We also work closely within our internal governance process and with our regulatory group to ensure appropriate communications with stakeholders and the Commission when large project costs exceed initial estimates.

4. *Major Capital Projects*

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

A. It is my understanding that the MYRP statute in Minnesota requires a utility to "provide a general description of the utility's major planned investments over the plan period." To comply with this requirement, we have identified the major nuclear capital projects we believe fall under this category of investments, and describe those projects below.

Q. HOW DID NUCLEAR IDENTIFY THE PROJECTS THAT FALL WITHIN THIS CATEGORY OF INVESTMENTS?

A. For purposes of ratemaking, we define "major capital projects" that contribute to our overall major planned investments as unique projects that will require a greater than normal quantity of Nuclear resources to complete.

Q. WHAT MAJOR CAPITAL PROJECTS DOES NUCLEAR ANTICIPATE COMPLETING OVER THE PERIOD OF THIS MULTI-YEAR RATE PLAN?

A. We anticipate undertaking 16 major capital projects during the period 2020 through 2022. These projects, depicted in Table 5 below, include:

Table 5

Major Capital Projects

Capital Grouping	Project	Number of Major Projects		
		2020	2021	2022
Dry Cask Storage	Dry Fuel Storage Loads	1		1
	PI ISFSI Expansion		1	
Mandated Compliance	PI Control Cluster Assembly Replacement	1	1	
	PI Modification of Switchgear Control Circuits	1		
	Monticello Security Pathway and Opening Modifications	1		
Reliability	PI Cooling Tower Rebuilds	1		
	Monticello Cooling Tower Upgrade		1	1
	PI Process Control System Replacement	1		
	PI Intake Traveling Screen Replacement			1
	PI Transformer Replacement			1
Improvements	Monticello Risk Informed Engineering Program		1	
	PI Purification Modification	1		
	PI Risk Informed Engineering Program		1	
Facilities & Other		-	-	-

Some of these projects span multiple years, with portions of the project placed in-service as they are put into use each year. The major capital projects we expect to complete during the plan period, as well as the additional key projects we anticipate completing in 2020-2022, are discussed in more detail under each plan year, below.

C. 2020 Capital Additions

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NUCLEAR CAPITAL ADDITIONS BUDGET FOR 2020.

A. The total NSPM Nuclear 2020 capital additions are budgeted to be $73.5 million for projects and $84.5 million for fuel. Table 6 below sets forth the anticipated capital additions for 2020 by major category:

Table 6

2020 Nuclear Major Categories	Total NSPM 2020 Additions Including AFUDC ($ in millions)
Dry Cask Storage	$14.1
Mandated Compliance	10.7
Reliability	28.9
Improvements	18.1
Facilities & Other	1.7
Subtotal – Projects	$73.5
Nuclear Fuel	84.5
Total Nuclear Additions	$158.0

Q. WHAT ARE THE PRIMARY DRIVERS OF THE 2020 CAPITAL ADDITIONS PLACED INTO SERVICE BY THE NUCLEAR OPERATIONS BUSINESS UNIT?

A. Project additions include dry cask storage loading at Prairie Island, Prairie Island Control Cluster Assembly Replacement, and a cooling tower rebuild and Process Control Systems Replacement project also at Prairie Island.

1. Dry Cask Storage

Q. WHAT ARE DRY CASK STORAGE PROJECTS?

A. Dry Cask Storage projects are associated with on-site dry spent fuel storage and loading campaigns, such as the ISFSI. Because the Federal Government has not yet identified a permanent, long-term spent fuel storage facility, the Company must store spent fuel on-site in the interim. The timing of spent fuel storage is also designed to enable a full core offload for each unit at any time, compliant with the Commission's Certificate of Need requirements. Because of the longer on-site storage now required, we will need to implement several aging management programs for the storage casks, including continued/extended licenses from the NRC.

Q. PROVIDE AN EXAMPLE OF A DRY CASK STORAGE PROJECT NUCLEAR OPERATIONS ANTICIPATES PLACING IN SERVICE IN 2020.

A. The only Dry Cask Storage project Nuclear anticipates placing in-service in 2020 relates to the loading and placement of TN-40 HT casks 45, 46 and 47 at the Prairie Island plant.

Q. WHAT IS THE 2020 TEST YEAR BUDGET FOR CAPITAL ADDITIONS FOR THIS PROJECT?

A. The Nuclear Operations business unit has established a budget of $14.1 million for this Dry Cask Storage project addition during the 2020 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. Earlier in my testimony I discussed the capital budgeting process and how we identify, prioritize, and assign funding to specific projects, and estimate expenditures and in-service dates by year.

With respect to this specific project, the budget for additions represents the accumulated capital expenditures and AFUDC incurred for these casks.

Q. WHAT ARE THE TRENDS IN DRY CASK STORAGE PROJECT ADDITIONS OVER THE LAST THREE YEARS, AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, Dry Cask Storage project additions have ranged from $1.4-68.4 million per year in 2016 to 2019. Cask additions were $19.8 million in 2016 and $13.5 million in 2017. Substantial dry cask work was completed in 2018 for $68.4 million. Forecasted additions for 2019 are $1.4 million. The budget for Dry Cask Storage additions in 2020 is about $14 million.

Q. WHAT IS DRIVING THESE VARIATIONS BY YEAR IN CASK ADDITIONS?

A. Dry Cask Storage project additions are different each year based on the specific needs for fuel storage at each site as refueling outages are completed, the spent fuel storage pools are filled, and ISFSI licensing approvals and activities proceed. As noted, the 2020 additions relate to the loading and placement of three TN-40HT casks at the Prairie Island ISFSI.

Q. DO YOU EXPECT SOME LEVEL OF VARIATIONS TO CONTINUE?

A. Yes, because the level of work required to complete dry storage installations will continue to vary each year. The dry storage containers authorized by the Commission will continue to be loaded periodically in order to support nuclear plant operations at Monticello and Prairie Island. The licenses for the dry storage installations will also have to be periodically amended in order to continue to comply with NRC regulations. The Prairie Island ISFSI license was renewed in 2015 and imposed Aging Management Programs (AMP) for dry cask storage at Prairie Island. The Monticello license has also been renewed and will require implementation of AMP sometime prior to 2028. Periodic dry cask storage licensing activities will continue at Prairie Island for activities such as ISFSI expansion to store up to 64 casks as previously authorized by the PUC, and the addition of new fuel types being used at Prairie Island, to the TN40HT license.

In addition to NRC requirements, another Certificate of Need will be required from the Commission to add the additional storage capacity necessary to support plant decommissioning, assuming dry cask storage is still required. In the most recent Triennial Decommissioning Accrual docket, the Commission approved the current annual accrual, finding this accrual was appropriate to support safe spent fuel management for 60 years after plant shutdown. We will continue to take all required actions to ensure the continued safe operation of these fuel storage facilities are compliant with NRC licenses and Commission requirements. The activities needed to meet these requirements will cause varying amounts of dry cask additions over the years.

a) Key 2020 Dry Cask Storage Project: Prairie Island TN40HT Cask Placement

Q. PLEASE DESCRIBE THE PROJECT.

A. This project includes the manufacture, delivery, loading and placement at the Prairie Island ISFSI of nine (9) TN-40HT casks, #39-47. The specific activities in 2020, leading to the capital addition budgeted, will be the loading and placement at the ISFSI of Casks #45, 46, and 47.

Q. DESCRIBE THE CASK LOADING PROCESS.

A. During a nuclear plant refueling, spent (used) fuel is removed from the reactor core and placed in the spent fuel pool for temporary storage. The spent fuel pool has limited capacity, and fuel must eventually be removed from the pool to make room for the next refueling. The plant is required to keep enough room in the spent fuel pool to accommodate a full reactor core offload. Fuel removed from the pool is loaded into metal dry shielded canisters, which have two lids that are installed one on top of the other. The canister loading process is facilitated by a specialized transfer cask that the canister is placed in during loading. The transfer cask is procured from our vendor AREVA. Inert gases are injected into the sealed casks to prevent degradation of the spent fuel during interim storage. The casks are loaded and sealed in the reactor building, and then transported to, and inserted into the ISFSI storage module located outside the plant. Ultimately, the loaded casks are to be moved off-site by the DOE once a permanent Federal storage site is approved and available. Until then, the spent fuel is stored on-site in casks in the ISFSI storage facility.

Q. PLEASE DESCRIBE THE PROJECT COSTS IN MORE DETAIL.

A. The 2020 capital addition for this project is $14.1 million, including AFUDC. The project costs include employee labor, outside contractors, materials and equipment, employee travel expenses associated with the project, and other costs such as equipment rental. The additions placed in service include AFUDC accrued during the project's duration. The budgeted capital addition for 2020 represents the costs associated with the management, oversight, loading and placement of Casks #45-47.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. This project supports Prairie Island Unit 1 and Unit 2 operations through the end of the current license, 2033 and 2034 respectively. As discussed previously, the Prairie Island plant continues to be a safe, reliable, and carbon-free source of energy for our customers and a cornerstone of our fleet. This project is part of the dry cask storage expansion approved by the Commission in 2009 in Docket No. E-002/CN-08-510.

2. *Mandated Compliance*

Q. WHAT PROJECTS ARE INCLUDED IN THE MANDATED COMPLIANCE GROUPING?

A. Mandated Compliance projects include regulatory, security, and license commitment activities required by federal or state regulators (normally the NRC), including industry commitments made to the NRC. They are driven by the requirements of the NRC or other regulators as a condition of maintaining our license to operate the plants. Mandated Compliance work is intended to implement new NRC regulations for the industry, often with a safety implication (such as fire protection).

Q. PLEASE PROVIDE EXAMPLES OF KEY MANDATED COMPLIANCE PROJECTS SCHEDULED TO GO IN SERVICE DURING THE 2020 TEST YEAR.

A. The three key Mandated Compliance projects with 2020 additions are work on the Prairie Island Unit 1 reactor control rods, continued implementation of fire protection modifications at Prairie Island, and modification of certain security pathways at Monticello. I discuss these 2020 project additions in more detail in the next set of questions in my testimony.

Q. WHAT IS THE 2020 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $10.7 million for Mandated Compliance project additions during the 2020 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. Earlier in my testimony I discussed the capital budgeting process and how we identify, prioritize, and assign funding to specific projects, and estimate expenditures and in-service dates by year.

Overall, the budget for additions represents the culmination of capital expenditures incurred over time for various Mandated Compliance projects that are expected to be completed and placed in service during 2020. We first establish scope, estimate cost, and build an activity schedule for each project, many of which span over several years. The cost estimates are used as a budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project revised, the cost estimate can be updated over the period the project is progress. The capital additions budget for 2020 represents the total of expenditures incurred, and AFUDC accrued over the project duration, that are expected to be completed and placed in-service during the year 2020.

Q. WHAT ARE THE TRENDS IN MANDATED COMPLIANCE PROJECTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, Mandated Compliance project additions ranged from $40-80 million per year in 2016 through 2018, with $3.8 million in forecasted additions for 2019. The 2020 budget for Mandated Compliance additions of $10.7 million is significantly lower than prior years, and currently expected to decrease further in 2021 and 2022.

Q. WHAT IS DRIVING THESE TRENDS?

A. The 2020 additions are largely related to completing the last outage for NFPA 805 modifications at Prairie Island, addressing compliance with NEI 09-05 security requirements, and compliance with regulations related to control rod component replacement. Each of these Mandated Compliance projects is explained in more detail below. The 2016-2019 timeframe shows a declining trend in Mandated Compliance Projects. The major drivers for this downward trend are completion of the Fukushima and EDG Tornado Missile Protection work at both sites and the wind down of the NFPA 805 Fire Model and Modification work at Prairie Island. In the 2016-2019 timeframe, the Mandated Compliance Projects placed into service included: Open Phase Detection Modifications at both stations (Byron Open Phase Event), the Hardened Vent Modifications at Monticello, the security protective strategy modifications at Monticello, and NFPA 805 modifications at Prairie Island (AFW Train Separation for both Units, Incipient Fire Detection Modification, CT11 and CT12 Bus Source Modifications). The downward trend in

Mandated Compliance is expected to continue in the 2020-2022 timeframe due to the completion of the NFPA 805 modifications and the lack of significant regulatory changes that would drive plant modifications.

a. Prairie Island Unit 1 Reactor Control Cluster Assemblies

Q. PLEASE DESCRIBE THE PROJECT.

A. This project replaces the active neutron absorbing portion of reactor control rods required to safely control and shutdown the reactor.

Q. WHAT ARE THE BENEFITS OF PROCEEDING WITH THIS PROJECT?

A. It is necessary to ensure compliance with NRC requirements. Control rods have a 15-year life that need to be replaced to continue operation of Unit 1.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The capital addition planned for 2020 is $3.2 million (including AFUDC). The project costs include engineering, materials, transport and storage, and installation.

Q. HOW WAS THE BUDGET FOR THIS PROJECT DEVELOPED?

A. The budget for control rod replacement is based on an estimate from the OEM, Westinghouse. The actual price paid for each control rod assembly will be based on the prices of silver and indium (constituent elements of the control rods) at the time of fabrication.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. No. The existing control rod cluster assemblies are at the end of their design life and require replacement to maintain compliance with our existing licensing basis. Because there is no change to our license basis or the design or function of the control rod assemblies, NRC approval is not required.

b. Fire Protection Program at Prairie Island

Q. PLEASE DESCRIBE THE PROJECT.

A. Nuclear's fire protection requirements under operating licenses are codified in Federal regulations (referred to as Appendix R). However, Appendix R provides some requirements that cannot readily be met regarding the separation of safety related equipment in the event of a fire. As this became an industry issue, the NRC offered nuclear operators a choice to comply with fire protection standards under one of two alternatives, at the operator's option. One option is the deterministic model under Appendix R. The other option is following the risk-informed, performance-based approach established by the National Fire Protection Association (NFPA) under its Standard No. 805. Implementation of an NFPA 805 program requires an NRC License Amendment Request (LAR). Implementation of all approved LAR projects is a condition of maintaining an operating license in good standing. The NRC has granted extensions of fire protection program compliance under NFPA 805 without regulatory findings (for non-compliance with Appendix R). The NRC compliance process for fire protection under NFPA 805 is then defined with the LAR approval schedule.

We evaluated the options for each of our sites. With respect to Monticello, the Company decided to proceed with Appendix R requirements as its fire protection program. As to Prairie Island, the Company elected to meet NFPA 805 requirements to provide more time to resolve Prairie Island's fire protection risk issues, and avoid potential non-compliance and NRC findings during the time it would take to comply fully with the Appendix R program. The NFPA 805 project scope at Prairie Island includes development of a fire protection model (evaluating risk to reactor core damage) and performance of a number of plant modifications to implement fire protection elements, which will be completed and put into service in stages through the final project close-out in 2021. This NFPA 805 modeling complies with NRC regulations for fire protection.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. The NRC allowed the choice of fire protection programs under either Appendix R or NFPA 805. Our analysis determined that the NFPA 805 risk-informed approach was more cost effective to mitigate the risks of reactor core damage frequency and large early radiation release, and to ensure the safe shutdown of the Prairie Island plant in the event of a fire. Using an Appendix R at Prairie Island would be cost prohibitive and uneconomical to address pending fire protection nonconformances (now being addressed throughout the NFPA 805 program) through the NRC's significance determination process. Risks associated with the consequences of a fire have been significantly reduced. The overcurrent protection systems are enhanced to maintain function as much as possible to critical Safety Related Power Sources that feed critical equipment that may be called upon to safely shutdown the reactor in case of an event.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2020 capital addition for this project is $3.2 million, including AFUDC. The project costs include employee labor, outside contractors, materials and equipment, employee travel expenses, and other costs associated with regulatory compliance. The costs include engineering and construction work for fire model development and implementation, and regulatory compliance activities for LAR preparation and submittal.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. Industry operating experience and benchmarking of NFPA 805 pilot plants were initially used for high level project cost estimates. Vendor estimates, additional industry operating experience, and our own experience, were used to refine the initial estimates and determine the program budget for the LAR preparation, submittal, fire model development, and administrative implementation costs. As each modification approaches implementation, the cost estimates will be further refined as specific scope and resource needs are finalized to meet NRC requirements for fire protection. The project duration and scope has expanded over time as the NRC has reviewed our implementation plans, issued requests for additional information, and provided additional guidance on their compliance expectations for fire protection. We continue to monitor the fire protection modifications made and costs incurred by other nuclear utilities to ensure our project costs are in line with the industry.

Q. WERE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. Yes. Satisfactory responses to the NRC's information requests have resulted in NRC approval through the NRC's Safety Evaluation Report, which occurred on August 8, 2017. Since the issuance of that Safety Evaluation Report for the NFPA 805 fire program, the NFPA 805 Transition License Condition has been in effect. This license condition allows a transition period to implement programmatic changes and facility modifications.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. We continue to proceed on our implementation timetable, putting phases of the fire protection project into service as completed. Programmatic changes were completed by August 8, 2018, within one year after issuance of the Safety Evaluation Report for the NFPA 805 fire program, as required. Facility modifications are underway and on track to conclude prior to the commitment dates and the plant operating license conditions (by November 2022 on Unit 1 and November 2021 on Unit 2), two complete refueling cycles after August 8, 2017 (the date of the NRC's issuance of the Safety Evaluation Report).

c. Monticello Security Compliance Project

Q. PLEASE DESCRIBE THE PROJECT.

A. The purpose of this project is to modify certain security pathways at Monticello to comply with NEI 09-05, "Guidance on the Protection of Unattended Openings that Intersect a Security Boundary," which provides approaches and methodologies that the NRC has found to be acceptable for use to meet the requirements of 10 CFR 73.55 for unattended openings that intersect a security boundary.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. This project will allow Monticello to comply with the requirements set forth in NEI 09-05 relating to protection of two-dimensional openings and three-dimensional pathways in security barriers at nuclear power reactor facilities. Current conditions at several locations were determined to be non-compliant with NEI 09-05. As a result, compensatory measures are currently in place to maintain compliance with the pathways regulation. Upon completion of the modifications, the compensatory measures can be removed.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2020 capital addition for this project is $2.1 million, including AFUDC. The project costs for the NEI 09-05 Securities Pathways project includes employee labor, outside contractors, and materials and equipment.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The budget for this project was developed by benchmarking similar construction projects that have been performed at the Company's Monticello and Prairie Island plants. This information was used to prepare the estimates which include engineering, field construction and oversight costs, as well as materials and overhead costs. Initial pricing was developed from engineering estimates and construction walkdowns. Estimates were refined as additional information was developed.

Q. WERE/ARE NRC APPROVALS NEEDED FOR THIS PROJECT?

A. No. As noted above, the intent of this project is to come into compliance with NEI 09-05 requirements for pathways. The NRC has already determined that compliance with NEI 09-05 complies with NRC regulations and allows for the elimination of compensatory measures, so no further approval is needed.

3. Reliability

Q. WHAT ARE RELIABILITY PROJECTS?

A. Reliability projects enhance equipment and generation reliability by reducing safety system unavailability and forced losses in production output, reducing the need for maintenance activities, and implementing life cycle aging equipment management/ replacement programs. They are driven by the fact that the Company's nuclear plants are all over 40 years old and require ongoing capital investment to maintain reliable operation through equipment upgrades and replacement. In effect, these projects are intended to, consistent with our NRC license obligation, make the plants "like new" under the renewed/extended operating licenses to 2030 for Monticello and 2033-2034 for Prairie Island, as well as the planned license extension at Monticello.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY RELIABILITY PROJECT SCHEDULED TO GO IN SERVICE DURING THE 2020 TEST YEAR.

A. The only large Reliability project with 2020 additions is a multi-year program to replace the Digital Feedwater Control System and Anticipated Transient Without Scram (ATWS) Mitigation System Actuation Circuitry system (Process Control Systems project). I discuss this 2020 project addition in more detail later in my testimony.

Q. WHAT IS THE 2020 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $29 million for Reliability project additions during the 2020 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. Earlier in my testimony I discussed the capital budgeting process and how we identify, prioritize, and assign funding to specific projects, and estimate expenditures and in-service dates by year.

Overall, the budget for additions represents the culmination of capital expenditures incurred over time for various Reliability projects that are expected to be completed and placed in-service during 2020. Our budget allotment to Reliability projects comes first from our strategy to meet operating performance goals set consistent with excellence standards from the NRC and INPO, as I discussed earlier.

For specific projects, we first establish scope, estimate cost, and build an activity schedule for each project, many of which span over several years. The cost estimates are used as a budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project revised, the cost estimate can be updated over the period the project is progress. The capital additions budget for 2020 represents the total of expenditures incurred, and AFUDC accrued over the project duration, that are expected to be completed and placed in-service during the year 2020.

Q. WHAT ARE THE TRENDS IN RELIABILITY PROJECTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, Reliability project additions have fluctuated from year to year based on the specific projects undertaken in each year. The 2020 budget for Reliability additions of $29 million is lower than the forecasted 2019 additions of $77 million and lower than the additions of $65 million in 2016, $80 million in 2017, and $138 million in 2018. As will be discussed later in my testimony, the budgeted Reliability additions are higher in both 2021 and 2022.

Q. WHAT IS DRIVING THESE TRENDS?

A. Reliability Projects makeup our largest project grouping. Annual reliability project spend for the 2016-2018 period was $80-110 million with reliability projects at Prairie Island making up a majority of that spend. Major projects in the category in the 2016-2018 timeframe for Prairie Island include the Unit 1 Generator Replacement, the Reactor Coolant Pump Rebuild, Refurbishment of the 124 and 123 Cooling Towers, Unit 1 Fan Coil Unit Face and Header Replacement, and the FW/AMSAC Process Controls Project. Major projects at Monticello during that time period include the Plant Process Computer Replacement (PPCS/DAS), Recirc MG Set Replacement, and Intermediate Range Nuclear Instrumentation Replacement (IRM).

Reliability projects in 2019 account for $46 Million with major projects including the Unit 2 FW/AMSAC Process Controls Replacement at Prairie Island, the 1R Transformer Replacement at Prairie Island, and Cooling Tower Refurbishments at both sites. Spend remains at the lower end of this range in 2020 ($37 Million) with an uptick in 2021 and 2022 driven by additional Cooling Tower Rebuilds at both sites, CT11 and CT12 Transformer Replacements at Prairie Island, and Replacement of the 121-128 Intake Traveling Screens at Prairie Island. The trend in the nuclear industry towards committing more capital investment to equipment reliability through replacement and refurbishment continues, as this work is needed to achieve performance excellence and cost efficiencies. High production output of 90 percent of capacity or more is consistent with top quartile operations. Our reliability commitment to achieve and maintain output to those levels ensures the delivery of 1700 megawatts of clean carbon-free energy to our customers, and leverages our cost per MWh over a larger base of production output.

Q. PLEASE DESCRIBE THE PROCESS CONTROLS REPLACEMENT PROJECT.

A. The existing Prairie Island Feedwater Control System is based on an older technology called WDPF (Westinghouse Distributed Processing Family). It is obsolete and is no longer supported by the vendor. There have been increasing equipment failures during the last several years on this system. This system controls feedwater flow from the condenser to the Steam Generators. A failure could result in a unit trip. This system also controls the ATWS Mitigation System Actuation Circuitry (AMSAC). Both the Feedwater Control System and the AMSAC are over 25 years old and are becoming obsolete.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. The project will lead to a significant number of reliability benefits. These include mitigating the obsolescence of the WDPF equipment and field equipment, as well as increasing the level of redundancy in a number of systems. Given the age of the current system, replacing it with more current technology will also provide new features that are not part of the existing system, such as error detection, self-checking, and system diagnostics. Overall, the reliability improvements will reduce reactivity events and operator burdens. The project will also provide functional control enhancements, such as better control algorithms that will improve dynamic response for control at varying power levels and control features such as anti-windup and bump-less transfers. The upgraded systems will allow for alternate control strategies and additional automated functions, as well as provide an improved operator interface with graphical displays providing better access to key system information.

This project will allow the plant to replace an obsolete system with a well-vetted, common platform with demonstrated history of reliable operation in many commercial nuclear plants. The vendor, Westinghouse, has committed to long-term support of this platform.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2020 capital addition for the Unit 1 Process Controls Replacement Project is $14.3 million, including AFUDC. The project costs include employee labor, outside contractors, materials and equipment, and some employee travel expenses associated with the project.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The detailed project estimate was developed based on vendor proposals for contracted services and materials, and underwent detailed management review and challenges to confirm accuracy.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. This change was evaluated under the 10 CFR 50.59 process, and does not require prior NRC approval. That said, given the operational significance and regulatory changes surrounding digital modifications at nuclear facilities, tabletop reviews were held with the NRC and key digital and regulatory experts from the industry in connection with this project.

4. Improvements

Q. WHAT ARE IMPROVEMENT PROJECTS?

A. Improvement projects improve system and operational performance and operation (for example, digital upgrades), and can reduce O&M costs. They enable us to capture opportunities for improved output or operational performance and efficiency, which can provide a payback for the investment through higher output or lower operating cost.

Q. HOW MUCH IS BUDGETED FOR CAPITAL ADDITIONS RELATED TO IMPROVEMENT PROJECTS IN THE 2020 TEST YEAR?

A. $18.1 million of capital additions are budgeted for Improvement projects.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. Earlier in my testimony I discussed the capital budgeting process and how we identify, prioritize, and assign funding to specific projects, and estimate expenditures and in-service dates by year.

Overall, the budget for additions represents the culmination of capital expenditures incurred over time for various Improvement projects that are expected to be completed and placed in-service during 2020. We first establish scope, estimate cost, and build an activity schedule for each project, many of which span over several years. The cost estimates are used as a budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project revised, the cost estimate can be updated over the period the project is progress. The capital additions budget for 2020 represents the total of expenditures incurred, and AFUDC accrued over the project duration, that are expected to be completed and placed in service during the year 2020.

Q. WHAT ARE THE TRENDS IN IMPROVEMENT PROJECTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, Improvement project additions can fluctuate from year to year based on the specific projects undertaken in each year. The 2020 budget for Improvement additions exceeds the entirety of the expenditure on Improvement projects from 2016-18.

Q. WHAT IS DRIVING THESE TRENDS?

A. The nature of Improvement projects is that while they are valuable projects that result in improved efficiency, Improvement projects are lower priority than projects in the Mandated Compliance and Reliability categories. As a result, they are completed as opportunities to improve arise and have funding capability given other priorities. In 2016-2017, when fewer Improvement projects were completed, other projects had higher priority in our balancing of risk and opportunity, most notably certain Reliability projects and Fukushima compliance work. Now that some of these larger Reliability projects and the Fukushima work has been completed, there is more room in the capital budget for Improvement projects. In 2018 and 2019 we undertook larger improvement projects with higher relative priority. In 2018 we completed the Turbine Supervisor Instrumentation upgrade at Prairie Island. In 2018 and 2019 both sites continued projects to update surveillance testing frequencies and engineering programs to a risk informed approach based on Probabilistic Risk Assessments (PRA). In 2019, we began a security project at Prairie Island that will strengthen the site's security strategy, and result in a reduction in staffed security posts. Prairie Island also implemented a project to tie the RHR system on Unit 2 to the purification system in 2019, which shortens outages by reducing the time required to clean up activity in the Reactor Coolant System. The Maintaining the Plant and the Fleet Excellence Plans both focus on maintaining and improving existing equipment rather than modification of the plants, which leads to an increase in Improvement projects.

Q. PLEASE DISCUSS THE KEY IMPROVEMENT PROJECTS BUDGETED TO GO IN SERVICE DURING THE 2020 TEST YEAR.

A. The most significant Improvement project addition budgeted in 2020 is the Security Strategy Upgrade at the Prairie Island plant, budgeted at $12.3 million for 2020. This project will design, procure, and install protective features that will increase the effectiveness of the Physical Security Plan (PSP) and reduce station O&M cost annually by reducing security posts.

The Security Strategy Upgrade at Prairie Island Nuclear Generating Plant (PINGP) will include physical and material upgrades and analysis upgrades. The physical and material upgrades will include: the installation of five (5) Bullet/Blast Resistant Enclosures (BBRE) with cameras; the extension of the Northwest corner of the Protected Area (PA); the installation of delay barriers at designated locations within the PA; the installation of barriers to protect Condensate Storage Tanks (CST); the installation of vehicle barriers near the Cooling Towers; and the establishment of firearm sights. The analysis upgrades will include updates to engineering calculations, associate analyses and plant drawings, as well as updates to the PSP and the Safeguards Contingency Plan.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT AT THIS TIME?

A. This project will allow a reduction in security posts, which will reduce O&M costs while also providing a robust protective strategy.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2020 capital addition for this project is $12.3 million, including AFUDC. The Security Strategy Upgrade at PINGP will design, procure, and install protective features that will increase the effectiveness of the Physical Security Plan (PSP) and reduce station O&M cost annually by reducing security posts. Key upgrades being installed by the Project include the addition, detection and delay features, technology improvements, and the installation of Bullet and Blast Resistant (BBRE) enclosures.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. An external vendor was commissioned to perform a Project Study to identify the optimal strategy that maximizes both cost benefits and protective feature enhancements to harden the PSP. The Project budget was an output of the Study and was developed through the combination of analogous estimating and direct vendor quotes for expected services and commodities. Xcel Energy supplemented the external vendor performing the Study with independent nuclear security experts, Xcel Energy security analysts, engineers, and project management resources.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. No NRC approval is required for this project. The Engineering Change was screened per the 10 CFR 50.59 process, and no LAR was required. The project will submit an updated Security Contingency Plan per the requirements of 10 CFR 50.54(p).

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. The Project has completed the initial design phase and executed the long-lead procurement for the BBRE enclosures. Construction activities are planned to begin in 2019 and complete in 2020. Project construction, training, and testing activities will be completed in time to support the NRC's Force-on-Force (FOF) inspection that is planned for the late 2020.

Q. IS THERE AN ADDITIONAL MAJOR IMPROVEMENT PROJECT BUDGETED TO HAVE CAPITAL ADDITIONS IN 2020?

A. Yes. The Purification Modification project at Prairie Island is budgeted to have a $2.3 million capital addition in 2020.

Q. PLEASE DESCRIBE THE PROJECT.

A. This project will install a pipe route from the discharge of the residual heat removal (RHR) pumps to the chemical volume control system (CVCS).

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT AT THIS TIME?

A. This project will expedite reactor coolant system (RCS) cleanup during a plant shutdown, which will reduce outage critical path duration by approximately 24 hours. Each unit will have approximately 200 feet of 2" piping installed in the Auxiliary Building. This will lead to savings due to reduced outage duration.

Q. PLEASE DESCRIBE THE PROJECT COSTS.

A. The 2020 capital addition for this project is $2.3 million, including AFUDC. The primary project costs are design engineering, field construction, and materials.

Q. HOW WAS THE BUDGET FOR THE PROJECT DEVELOPED?

A. The budget was developed based on a formal estimate produced by the projects department. The project estimate included cost inputs from engineering and construction which, in turn, were based on field walkdowns of the propose pipe route.

Q. IS NRC APPROVAL REQUIRED FOR THIS PROJECT?

A. No. This project was evaluated under the 10 CFR 50.59 process. The screening of the changes under the 10 CFR 50.59 process determined that the modification does not require prior NRC approval.

Q. WHAT IS THE CURRENT STATUS OF THE PROJECT?

A. Unit 2 will be completed in October of 2019, and Unit 1 will be completed in the summer of 2020.

5. Facilities and Other

Q. WHAT ARE FACILITIES AND OTHER PROJECTS?

A. The Facilities and Other grouping includes facility work such as building improvements, roof replacements, road repairs, and general plant additions such as small tools and equipment. They are ongoing activities to maintain plant buildings and properties, and provide small tools and equipment to support normal plant operation.

Q. WHAT IS THE 2020 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $1.7 million for Facilities and Other project additions during the 2020 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. Earlier in my testimony I discussed the capital budgeting process and how we identify, prioritize, and assign funding to specific projects, and estimate expenditures and in-service dates by year.

Overall, the budget for additions represents the culmination of capital expenditures incurred over time for various Facilities and Other projects that are expected to be completed and placed in-service during 2020. We first establish scope, estimate cost, and build an activity schedule for each project, many of which span over several years. The cost estimates are used as a budget for project management. If scope or schedule change, emergent issues arise, or resources used for the project revised, the cost estimate can be updated over the period the project is progress. The capital additions budget for 2020 represents the total of expenditures incurred, and AFUDC accrued over the project duration, that are expected to be completed and placed in service during the year 2020.

Q. WHAT ARE THE TRENDS IN FACILITIES AND OTHER PROJECTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, Facilities and Other project additions have fluctuated from year to year based on the specific projects undertaken in each year. The 2020 budget for Facilities and Other additions of $1.7 million is lower than the 2016 additions of $4.3 million, but higher than the 2017 additions of $0.5 million, 2018 additions of $0.8 million and forecasted 2019 additions of $0.9 million.

Q. WHAT IS DRIVING THESE TRENDS?

A. In general, Facilities and Other additions tend to be the smallest capital project grouping, except when significant projects are a priority. In general, Facilities and Other additions tend to be the smallest capital project grouping, except when significant projects are a priority. Excluding significant projects, during the 2016-2019 timeframe the Facilities and Other additions have been consistent between $750K- $1.7M per year. In 2016, three significant facilities projects were completed. At Monticello the parking lot was repaved and the PAB and EDG Building Roofs were replaced. At Prairie Island the Turbine Building Crane was upgraded. These three significant projects made up three quarters of the Facilities additions in 2016.

Q. ARE ANY MAJOR FACILITIES AND OTHER PROJECTS BUDGETED TO HAVE CAPITAL ADDITIONS IN 2020?

A. No. The total 2020 capital additions for Facilities and Other projects is just $1.7 million, so there are no individual major projects for the 2020 test year.

6. Fuel

Q. WHAT ARE FUEL PROJECTS?

A. Fuel capital additions relate to the nuclear fuel loaded into the reactor to provide the heat energy that turns the turbine and powers the plants' generators. In fossil plants, fuel such as coal is delivered to the plant, stored on-site as inventory, and then loaded in the plant to burn. For nuclear plants, we contract with outside vendors to purchase uranium (called yellowcake), convert the uranium to a gaseous state, enrich and fabricate the uranium gas into fuel pellets and assemblies usable in the reactor, and install the fuel assemblies during refueling outages. In-house fuel engineers also design the fuel process at each site, working to optimize the type of fuel, configuration of assemblies, and reloading plans.

Because this process takes almost two years from beginning to end, and because the fuel lasts for multiple years until it is fully used up, nuclear fuel expenditures are considered capital work. The various fuel expenditures are accumulated in CWIP, AFUDC is accrued, and the fuel is considered placed in-service when loaded in the reactor during the unit's refueling outage. Fuel is then consumed over approximately three refueling cycles, and one-third of the fuel assemblies are removed and replaced in each refueling outage. Fuel is amortized over the period it is loaded in the reactor, which for three refueling cycles would be 4.5 to 6 years (based on cycles of 18 to 24 months, respectively). Each unit's fuel is loaded as an addition every other year, so with three units we would alternate years with two fuel projects when Monticello and Prairie Island both have a refueling, with years with one project when only Prairie Island has a refueling.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FUEL PROJECT SCHEDULED TO GO IN-SERVICE DURING THE 2020 TEST YEAR.

A. The test year 2020 has only one fuel project with capital additions, the reload for Prairie Island Unit 1.

Q. WHAT IS THE 2020 TEST YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $84.5 million for the PI Unit 1 fuel project addition during the 2020 test year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. The budgeting for nuclear fuel additions is different than the process described earlier in my testimony for other capital projects. The costs incurred for uranium purchase, conversion, and enrichment are tracked using segregated units of measure and applied to refueling loads using an average cost methodology. Engineering and fabrication costs are accounted for on a project-specific basis.

See additional details in Exhibit___(TJO-1), Schedule 3, regarding the nature of capital fuel expenditures, the process used to estimate and track nuclear fuel costs, the number of assemblies in each fuel reload, and the specific types of fuel costs included in budgets for capital fuel expenditures and additions over various periods including the test year 2020.

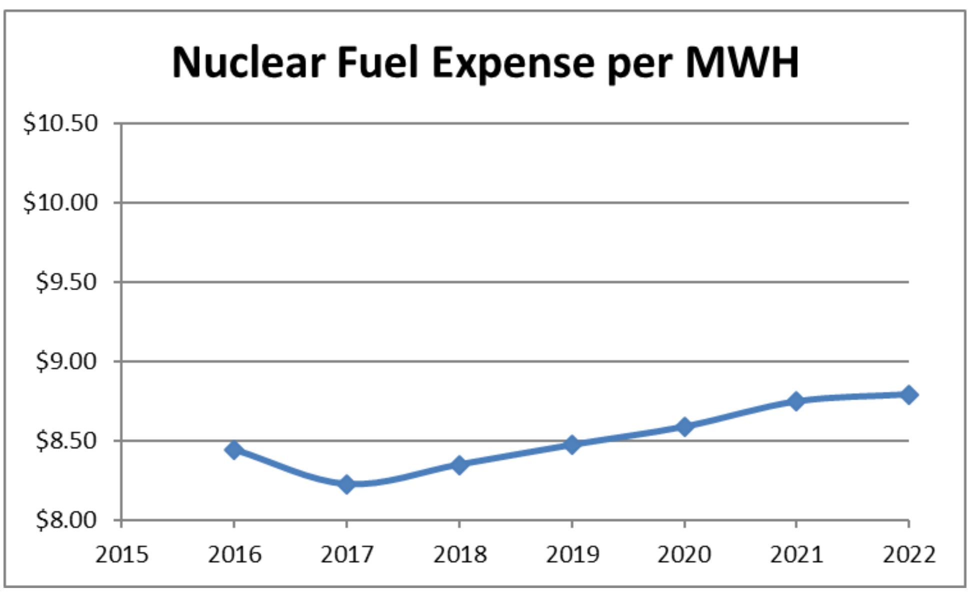
Q. WHAT ARE THE TRENDS IN FUEL PROJECT ADDITIONS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 4 from earlier in my testimony shows, fuel project additions fluctuate from year to year largely based on whether they include a refueling for a single unit or for two units. Comparing single refueling years, the 2020 budget for fuel additions of $84.5 million is higher than 2016 additions of $68 million but only slightly higher than 2018 additions of $82 million.

Q. WHAT IS DRIVING THESE TRENDS?

A. Each fuel load varies as to the number of assemblies installed in the reactor. In addition, the increase in 2017 is reflected by the transition to fuel supplied by AREVA (now Framatome) for the Monticello Reload for Cycle 29 of $17M and the increase in 2018 is reflected by the GAD/IFBA project for Prairie Island Unit 1 Reload for Cycle 31 of $6.5M. The GAD/IFBA project consisted of a combination of burnable absorbers, Gadolinia and Integral Fuel Burnable Absorber, in the fuel design that allowed the movement to 24-month cycles and eliminating two refueling outages over the life of the plant. Figure 1 below summarizes our amortized cost of capital fuel additions, expressed as fuel expense per MWh, over the periods 2016-2018 (actual), 2019 (forecast), 2020 (budget) and 2021-2022 (preliminary budget).

Figure 1



We continue to monitor industry initiatives and search for opportunities to reduce the cost of nuclear fuel. There are a number of ongoing industry initiatives that we are following and, as appropriate, participating in that will help to reduce the cost of nuclear fuel. These include a number of advanced nuclear fuel initiatives such as increasing the burn-up limits and enrichment levels for nuclear fuel. Both will allow more efficient use of the fuel by reducing the number of fuel assemblies necessary to support each reload.

We are also actively pursuing the use of the next generation of fuel assemblies at our Monticello plant. These new fuel assemblies provide for greater efficiency in the use of the uranium.

Finally, a number of our long-term nuclear fuel supply contracts are ending within the next five years. We are evaluating the current market conditions and the long-term market forecasts provided by several industry consultants to enhance our strategy for contracting for future nuclear fuel commodity supply.

See additional details in Schedule 3, regarding the nature and specific types of fuel costs included in capitalized fuel expenditures, additions and amortized costs over various periods including 2020.

Q. ARE NRC APPROVALS NEEDED FOR FUEL PROJECTS?

A. Yes. As noted above, the fuel fabrication supplier for our Monticello plant has introduced a new fuel design that is more efficient than our current fuel design and we are pursuing using this new fuel design at our Monticello plant to reduce fuel costs. The use of this new fuel design will require NRC approval prior to use. The work to obtain approval will occur from 2020 – 2023, with the first use of the fuel planned for the 2023 refueling.

D. 2021 Capital Additions

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NUCLEAR CAPITAL ADDITIONS BUDGET FOR 2021.

A. The total NSPM Nuclear 2021 capital additions are budgeted to be $95.4 million for projects and $152.7 million for fuel.

Q. WHAT ARE THE PRIMARY DRIVERS OF THE 2021 CAPITAL ADDITIONS PLACED INTO SERVICE BY THE NUCLEAR OPERATIONS BUSINESS UNIT?

A. Project additions include approximately $14.6 million for the Prairie Island ISFSI expansion project, $10.5 million for a Cooling Tower rebuild at Prairie Island, and $9.5 million for a cooling tower upgrade at Monticello. Fuel additions are an ongoing capital requirement over the refueling cycles of each plant, and in 2021 we will have two refueling; one at Monticello and one at PI Unit 2.

1. Dry Cask Storage

Q. WHAT IS THE 2021 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The 2021 budget for capital additions for Dry Cask Storage is $14.7 million. This is primarily a single project, the Prairie Island ISFSI Expansion.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2020 Dry Cask Storage projects.

Q. PLEASE DESCRIBE THIS PROJECT.

A. The Prairie Island ISFSI Expansion Project will increase the capacity of the

ISFSI from 48 to 64 TN-40 HT casks.

Q. WHAT IS THE BENEFIT OF THIS PROJECT?

A. The Prairie Island ISFSI Expansion Project supports the continued operation of Prairie Island Units 1 and 2 through the end of their current licenses, in 2033 and 2034, respectively. These units continue to provide critical efficient and reliable carbon-free resources for our customers.

2. *Mandated Compliance*

Q. WHAT IS THE 2021 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $4.6 million for Mandated Compliance project additions during the 2021 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2020 Mandated Compliance projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY MANDATED COMPLIANCE PROJECT PLANNED TO GO IN-SERVICE DURING THE 2021 PLAN YEAR.

A. Nuclear has budgeted about $3.3 million in capital additions in 2021 to replace the active neutron absorbing portion of reactor control rods at Prairie Island Unit 2, that are required to safely control and shutdown the reactor. I previously described this project in my testimony as the same work will be done at Prairie Island Unit 1 in 2020. None of the remaining 2021 additions for Mandated Compliance are considered key on their own. Of course, continued compliance with NRC requirements is important and we will continue work in that regard.

Q. WHY IS THIS PROJECT BEING UNDERTAKEN IN 2021?

A. This is a required project. These control rods have a 15-year life and must be replaced to continue operation of Unit 2.

3. *Reliability*

Q. WHAT IS THE 2021 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $65.5 million for Reliability project additions during the 2021 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2021 Reliability projects.

Q. PLEASE DESCRIBE THE KEY RELIABILITY PROJECTS PLANNED TO GO IN-SERVICE DURING THE 2021 PLAN YEAR.

A. The two largest Reliability project capital additions are the Prairie Island 122 Cooling Tower Rebuild and the Monticello Cooling Tower Upgrades Phase II project.

a. *Prairie Island Cooling Tower 122 Rebuild*

Q. PLEASE DESCRIBE THE PROJECT.

A. There are four cooling towers at the plant site, and this is a multi-year program with Cooling Tower 122 planned for 2021 and Cooling Tower 121 planned for 2022. The project addresses long-term material degradations and restores the condition of the Prairie Island cooling towers to support continued plant operations. The objectives of this project are to: (1) ensure cooling water compliance with state environmental regulations under National Pollutant Discharge Elimination System (NPDES) permits issued by the Minnesota Pollution Control Agency; and (2) facilitate adequate cooling water availability to continue operation of the plants at 100 percent of output capacity.

The project includes (1) replacement of the horizontal structural members, fill supports, and fill; (2) replacement of the flow distribution headers, valves, and supports; (3) replacement of the hot-water deck and associated supports; (4) partial replacement of the fan deck and supports, (4) replacement 8 fan-motor drive units; (5) replacement of the Outside Louvers; (6) replacement of drift eliminators; (7) replacement of Cooling Tower Lighting; and (8) installation of upper plenum walkway extensions.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. This project is essential to ensure compliance with our NPDES permit requirements, which is necessary for the Company to maintain compliance with state and federal environmental laws. This project will also improve cooling equipment reliability for plant operations, eliminate the risks of de-rating the unit in the event of cooling issues from equipment failures, and reduce maintenance repairs that would continue to be necessary without this project. In short, this project keeps us environmentally responsible and puts our cooling equipment in good working condition for the long run.

Q. DID NUCLEAR CONSIDER OTHER OPTIONS, RATHER THAN A REBUILD?

A. Yes. In fact, in our 2015 rate case, I discussed our then current plan to replace the Cooling Towers at Prairie Island. However, based on the results of inspections and the results of our Cooling Tower 124 project, we determined that the most cost effective manner of achieving the goals outlined above was through a rebuild, rather than full replacement or other options such as a partial refurbishment.

Q. HOW DID NUCLEAR DEVELOP THE BUDGET FOR THIS PROJECT?

A. The 2021 capital addition for this project of approximately $10.5 million reflects the employee labor, outside contractors, materials and equipment, and other costs such as tool/equipment rentals necessary to complete this work. The project's work scoping document was created and reviewed by Nuclear management. The approved scoping document was used to develop detailed requests for quotes and proposals from multiple vendors for tower header replacement (services and materials). Internal labor cost estimates were developed using inputs from each of the responsible work groups supporting the project and historical operating experience. The in-service dates were developed to support and align with the allowable out of service windows for our Cooling Towers based on applicable NPDES permit requirements.

We have done internal benchmarking of similar cooling tower work performed on the Company's Sherco and King coal plants, in addition to incorporating lessons learned and actual costs from the 124 and 123 Cooling Tower refurbishments at Prairie Island. We also had the vendor for the Prairie Island materials procurement and construction project provide an order of magnitude cost estimate for the complete structural overhaul of our cooling towers. Data from those sources was used to prepare the detailed estimates for this project's total costs, including site/contract engineering, field oversight, management and administrative overheads, and contingencies.

b. Monticello Cooling Tower Upgrades, Phase II

Q. PLEASE DESCRIBE THE PROJECT.

A. The project will rebuild Cooling Tower 11CT at Monticello. The 2021 capital addition for this project of approximately $9.5 million reflects the employee labor, outside contractors, materials and equipment, and other costs such as tool/equipment rentals necessary to complete this work. The project will tear down the existing cooling tower and rebuild with all new structure and components. This is a multi-year program with Cooling Tower 11CT planned for 2021 and Cooling Tower 12CT planned for 2022. The Monticello Project to rebuild the cooling towers will take place over the next 3 years, 2019 - 2022.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. Like the cooling tower rebuild at Prairie Island, this project is needed to maintain compliance with our NPDES permit. These cooling tower rebuilds will ensure structural integrity for continued operation. Without refurbishing or replacement, these cooling towers will not make it to the end of license. Both towers are currently supported by temporary shoring, so the plant is able to operate them. Additionally, improvements in materials and equipment will also reduce the amount of annual maintenance the towers currently require. Another benefit is that the rebuilds will ensure that the life of the cooling towers can extend to end of plant life.

Q. DID NUCLEAR CONSIDER OTHER OPTIONS, RATHER THAN A REBUILD?

A. Yes. The other option considered for the cooling tower project was cell-by-cell refurbishment. Initial estimates indicated that this option was not as cost effective as the rebuild option. In addition, the refurbishment option would not include all new equipment and would not result in reduction of annual project maintenance that the fiberglass towers will bring.

Q. HOW DID NUCLEAR DEVELOP THE BUDGET FOR THIS PROJECT?

A. The budget for this project was based on other cooling tower rebuilds/refurbishments done by Xcel Energy, as well as vendor proposals for the same work scope. We have done internal benchmarking of similar cooling tower work performed on the Company's Sherco and King coal plants. We also had the vendor for the Prairie Island materials procurement and construction project provide an order of magnitude cost estimate for the complete structural overhaul of our cooling towers. Benchmarking data from those two sources was used to prepare the high-level estimates for this project's total costs, including site/contract engineering, field oversight, management and administrative overheads, and contingencies.

4. Improvements

Q. WHAT IS THE 2021 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $10.1 million for Improvement project additions during the 2021 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2020 Improvement projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY IMPROVEMENT PROJECT PLANNED TO GO IN-SERVICE DURING THE 2021 PLAN YEAR.

A. There are two key Improvement Projects slated for 2021. These projects implement the RIEP project at Monticello and Prairie Island and the RICT project, also at Monticello and Prairie Island. The projected capital addition is $5.3 million for RIEP and $1.4 million for RICT. For the RIEP, the project will install a program that allows risk analysis of select systems where components are re-categorized into high or low risk; and if low risk, exemption from certain program requirements is permitted. For the RICT project, we will install a program that will allow changes in Limiting Condition of Operation (LCO) durations consistent with the risk of extending the LCO time.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. The RIEP project will result in estimated savings of $1 million per year due to cost savings on parts exempted from programs. The RICT will result in estimated savings of $250,000 per year due to more efficient operation.

Q. HOW DID NUCLEAR DEVELOP THE BUDGET FOR THIS PROJECT?

A. The Project was initiated with a study to determine the most cost effective strategy for implementation. Once the study was approved, the detail necessary to carry out program implementation was defined using project management method outlined in the project management manual. These activities were logically arranged and detailed costs developed for each activity. The overall costs were derived from the summation of individual activities.

5. Facilities and Other

Q. WHAT IS THE 2021 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS CATEGORY?

A. The Nuclear Operations business unit has established a budget of $0.6 million for Facilities and Other project additions during the 2021 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2020 Facilities and Other projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FACILITIES AND OTHER PROJECT PLANNED TO GO IN-SERVICE DURING THE 2021 PLAN YEAR.

A. The total amount of Facilities and Other project additions in 2021 is only $0.6 million for both sites, and thus no individual projects are considered key for that year.

6. Fuel

Q. WHAT IS THE 2021 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS TO THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $152.7 million for Fuel project additions during the 2021 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2020 Fuel projects. See additional details in Schedule 3, regarding the nature of capital fuel expenditures, the process used to estimate and track fuel costs, the number of assemblies in each fuel reload, and the specific types of fuel costs included in budgets for capital fuel expenditures and additions over various periods including 2021.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FUEL PROJECT PLANNED TO GO IN SERVICE DURING THE 2021 PLAN YEAR.

A. During 2021 we plan to complete two large outage refueling projects, one at Monticello and one at Prairie Island Unit 2.

E. 2022 Capital Additions

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NUCLEAR CAPITAL ADDITIONS BUDGET FOR 2018.

A. The total NSPM Nuclear 2022 capital additions are budgeted to be approximately $94.3 million for projects and $74.6 million for fuel.

Q. WHAT ARE THE PRIMARY DRIVERS OF THE 2022 CAPITAL ADDITIONS PLACED INTO SERVICE BY THE NUCLEAR OPERATIONS BUSINESS UNIT?

A. Project additions include $62.0 million for equipment reliability and $29.2 million for dry cask storage work. The principal reliability additions relate to Phase III of the Monticello Cooling Tower Upgrades, replacement of intake traveling screens at Prairie Island and the replacement of the CT 11 Transformer and CT 12 Transformer at Prairie Island. Fuel additions are an ongoing capital requirement over the refueling cycles of each plant, and in 2022 we have one fuel reloading at Prairie Island Unit 1.

1. Dry Cask Storage

Q. WHAT IS THE SIGNIFICANT DRY CASK STORAGE PROJECT FOR THE 2022 PLAN YEAR?

A. The significant dry cask storage project Nuclear anticipates placing in service in 2022 relates to the loading and placement of casks 48 to 50 at the Prairie Island plant. This is a multi-year project that will is forecasted to continue through 2032.

Q. WHAT IS THE 2022 TEST YEAR BUDGET FOR CAPITAL ADDITIONS FOR THIS PROJECT?

A. The Nuclear Operations business unit has established a budget of $28.1 million for this Dry Cask Storage project addition during the 2022 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2020 Dry Cask Storage projects.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. The project supports the continuing operation of Prairie Island Units 1 and 2 through the end of the current licenses, 2033 and 2034, respectively.

2. Mandated Compliance

Q. WHAT IS THE 2022 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $1.0 million for Mandated Compliance project additions during the 2022 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2020 Mandated Compliance projects.

Q. CAN YOU PROVIDE AN EXAMPLE OF A KEY MANDATED COMPLIANCE PROJECT PLANNED TO GO IN SERVICE DURING THE 2022 PLAN YEAR.

A. The total amount of Mandated Compliance project additions in 2022 is only $1.0 million, thus I do not discuss any individual Mandated Compliance project.

3. Reliability

Q. WHAT IS THE 2022 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $62.0 million for Reliability project additions during the 2022 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2020 Reliability projects.

Q. PLEASE DESCRIBE THE KEY RELIABILITY PROJECTS PLANNED TO GO IN-SERVICE DURING THE 2022 PLAN YEAR.

A. The three largest Reliability project capital additions are Phase III of the Monticello Cooling Tower Upgrades, replacement of intake traveling screens at Prairie Island and the replacement of the CT11 Transformer and the CT 12 Transformer.

a. *Monticello Cooling Tower Upgrade, Phase III*

Q. PLEASE DESCRIBE THE PROJECT.

A. This project is similar to Phase II of this Project, which is slated for 2021, but will rebuild Cooling Tower 12CT at Monticello. Like the cooling tower rebuild at Prairie Island, this project is needed to maintain compliance with our NPDES permit. I discussed this project earlier in my testimony in connection with 2021 capital additions.

b. Replacement of Intake Traveling Screens at Prairie Island

Q. PLEASE DESCRIBE THE PROJECT.

A. This Project will replace all eight Intake Traveling Screens, which have reached the end of their design life and are experiencing structural degradation of the track support and guide assemblies as well as the concrete foundation for the lower track support.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. A. Like the cooling tower rebuilds I discussed earlier, this project is needed to comply with our NPDES permit. The existing screens will be replaced with an improved design that will extend the life of the screens to the end of plant life, improve overall reliability and performance, and also reduce annual maintenance costs.

Q. DID NUCLEAR CONSIDER OTHER OPTIONS RATHER THAN REPLACEMENT?

A. Yes. Another strategy would be to continue with the current maintenance strategy. However, continued structural deterioration and parts obsolescence make this strategy less effective. As noted above, the intake traveling screens must be operational for Prairie Island to remain in compliance with our NPDES Permit.

Q. HOW DID NUCLEAR DEVELOP THE BUDGET FOR THIS PROJECT?

A. Benchmarking was performed at another Xcel site while in the construction phase of replacing similar screens. Project scoping considered the option for equivalent screens and an alternate option for an updated design screen. The most cost effective option is being selected based on project costs and ongoing O&M costs.

c. Replacement of the CT11 Transformer and CT12 Transformer at Prairie Island

Q. PLEASE DESCRIBE THE PROJECT.

A. This Project will replace the CT11 Transformer and CT12 Transformer at Prairie Island, based on EPRI and estimated service-life of transformers. Replacement transformer upgrades include automatic load tap changer and dissolved gas in oil monitor.

Q. WHAT IS THE BENEFIT OF PROCEEDING WITH THIS PROJECT?

A. Replacement of transformers that have been degraded by age reduces the likelihood of failure of these transformers. Failure of the transformers impacts cooling tower capability and reliability of power to safety buses.

Q. DID NUCLEAR CONSIDER OTHER OPTIONS RATHER THAN REPLACEMENT?

A. No. Overhaul of transformers to achieve acceptable reliability and performance is not cost effective.

Q. HOW DID NUCLEAR DEVELOP THE BUDGET FOR THIS PROJECT?

A. The budget estimate was based on actual costs for recent comparable auxiliary transformer (2M and 1R) replacement projects at Prairie Island with adjustments for scope differences, cost escalation, and contingency. For example, the CT11 and CT12 transformers are smaller and replacement is less complex than 1R. Thus, the base estimate for each CT transformer was reduced from that of 1R. As described above, the budget was then adjusted for installation of both transformers, engineering, inflation, and contingency.

4. *Improvements*

Q. WHAT IS THE 2022 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $0.7 million for Improvement project additions during the 2022 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2020 Improvement projects.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY IMPROVEMENT PROJECT PLANNED TO GO IN SERVICE DURING THE 2022 PLAN YEAR.

A. The total amount of Improvement project additions in 2022 is only $0.7 million for both plant sites. Thus, I do not discuss individual projects in my testimony.

5. Facilities and Other

Q. WHAT IS THE 2022 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $1.3 million for Facilities and Other project additions during the 2022 plan year, using the same capital project budgeting process I discussed earlier in my testimony for 2020 Facilities and Other projects. Since the total amount of Facilities and Other project additions in 2022 is only $1.3 million for both sites, I have not discussed individual projects in my testimony.

6. Fuel

Q. WHAT IS THE 2022 PLAN YEAR BUDGET FOR CAPITAL ADDITIONS IN THIS GROUPING?

A. The Nuclear Operations business unit has established a budget of $74.6 million for fuel project additions during the 2022 plan year.

Q. HOW DID YOU ESTABLISH THAT BUDGET?

A. We used the same capital project budgeting process I discussed earlier in my testimony for 2020 Fuel projects. See additional details in Schedule 3, regarding the nature of capital fuel expenditures, the process used to estimate and track fuel costs, the number of assemblies in each fuel reload, and the specific types of fuel costs included in budgets for capital fuel expenditures and additions over various periods including 2022.

Q. PLEASE PROVIDE AN EXAMPLE OF A KEY FUEL PROJECT PLANNED TO GO IN-SERVICE DURING THE 2022 PLAN YEAR.

A. During 2022 we plan to complete only one fuel project, a refueling at Prairie

Island Unit 1 during its scheduled outage that year. All of the budgeted fuel additions for 2022 relate to this project.

IV. NON-OUTAGE O&M BUDGET

A. Overview and Trends

Q. HOW IS YOUR TESTIMONY ORGANIZED IN THIS SECTION?

A. I first provide a discussion of the overall request for our non-outage O&M expenses and briefly describe the initiatives that we are taking in an attempt to reduce our cost growth (with a goal of keeping costs flat on an average annual basis) while at the same time improve safety, reliability, and performance. I then discuss the major cost categories included in the test year with a discussion of the drivers behind any changes. The O&M expenses related to our planned maintenance/refueling outages are discussed in Section V of my testimony.

Q. WHAT IS INCLUDED IN YOUR O&M BUDGET?

A. We split non-outage O&M items into two general cost categories associated with operating our nuclear plants: Workforce costs and Non-Workforce costs. Non-outage Workforce costs include employee labor, non-employee contractors and consultants, and security contractors. Non-Workforce costs consist of material costs, employee expenses, nuclear-related fees, and other expenses.

Q. HOW DOES THE COMPANY SET THE NON-OUTAGE O&M BUDGET FOR THE NUCLEAR OPERATIONS BUSINESS UNIT?

A. As an Xcel Energy business area, Nuclear Operations follows the budget process established by the corporate Financial Performance and Planning group, as discussed in the testimony of Company witness Mr. Greg Robinson. The starting point for that area developing the O&M spending guidelines is the most recent five-year financial forecast. Specifically, the starting point for the 2020-2024 Budgets was the most recent five-year (2019-2023) forecast. The Financial Council reviews this information, considering Xcel Energy's business plans and a number of other factors. After considering this information, the Financial Council establishes overall growth target guidelines for the new five-year O&M budgets, which each business area is expected to meet.

Once overall O&M spending guidelines are determined and communicated, the Nuclear Operations budgets are built from the "bottom up" by individual components, such as employee labor, contract labor, consulting costs, and materials expense by budget managers. In the example of labor, current salary and headcount data is fed from our payroll system to our budgeting system. Planned headcount additions over the five-year period are added to the budget system based on current workforce plans; projected merit increases are applied by the corporate budgeting group, based on the assumptions provided in the corporate budget instructions, and approved by Human Resources.

The budgets are built in detail, and not based simply on prior year costs, to which an inflation factor could be applied. However, the corporate budget instructions provide cost escalation factors to apply, if needed, for those costs to which inflation-based growth is appropriate to apply. The Nuclear Operations business area reviews the budgets submitted by department managers at each of the three sites with the responsible Vice President. As part of our effort to meet corporate targets, adjustments are usually made after the site reviews before being submitted for review with the Chief Nuclear Officer.

Q. DOES THE NUCLEAR OPERATIONS BUSINESS UNIT EVER NEED TO CHANGE THE COMPOSITION OF O&M AMONG NON-OUTAGE CATEGORIES, OR BETWEEN OUTAGE AND NON-OUTAGE DURING THE FINANCIAL YEAR?

A. Yes. Since the budgets are prepared about eight months in advance of the budget year, emergent items routinely arise that require a reprioritization of authorized spend levels. Examples of these emergent O&M items are forced outages and extensions to planned outages. In the Nuclear Operations area, a budget manager completes a form to request approval to spend money on an unbudgeted item. The manager can propose to use budgeted dollars from a different line item in his/her own budget, or ask for help in identifying savings from another department to cover the emergent cost. For a more costly unforeseen event such as a forced outage, there may be a need to find budget savings on a broader scale, such as in other departments at that site, or across the entire Nuclear Operations business area.

When planned outage costs rise, Nuclear Operations is still expected to manage to its overall O&M target/budget, including both non-outage and outage costs. Thus, in the event that planned outage costs vary from budget, we may need to reprioritize and adjust non-outage costs in order to meet our

O&M commitments for the year. In general, the corporate expectation is that each business unit (including Nuclear) should offset or absorb unplanned O&M costs and in so doing hold our cost levels to the budgeted targets used to determine customer rates.

Q. PLEASE EXPLAIN HOW THE NUCLEAR OPERATIONS BUSINESS UNIT MONITORS NON-OUTAGE O&M EXPENSES AFTER THE BUDGET IS CREATED.

A. Like all business areas, Nuclear is accountable for managing to its O&M budget for the year. The budget managers in each department are required to evaluate their ability to meet their budget as part of the monthly forecast process, with the help of the Nuclear Finance staff. This allows the business area to compare the approved budget with updated forecasts of spend, including actuals to date and estimates through end of year, that reflect changes in business operations that could not have been anticipated at the time the budget was first approved. Each site holds monthly financial meetings where budget managers describe the results for the current month compared to the forecast, any changes to expected year-end results, and risks (of higher costs) or opportunities (for lower costs) that have not yet been reflected in the forecast. In addition, I hold a monthly meeting with my direct reports to review the status of financial performance of the entire Nuclear business area, and to assess what actions may be needed to manage to the overall O&M budget.

Q. HOW DOES THE COMPANY DETERMINE ITS FORECAST OF CHANGES NEEDED FROM THE NON-OUTAGE O&M BUDGET?

A. The Company's ongoing financial governance process allows a business area to adjust, on a continuing basis, its business plans and financial forecasts.

For example, a business area (such as Nuclear) may face cost increases or new items not anticipated at the time the budget was created, or may need to reduce, delay, or accelerate spending in response to emerging new priorities, or unforeseen or changed circumstances. The monthly forecasting process allows those changes to be properly reflected in our business plans and forecasts. However, each business area is responsible for managing to their original O&M budget as approved, so when unforeseen costs occur, the business area makes every attempt to absorb them within their budget by reprioritizing other work. If they are unable to do so, the business area can request to increase their O&M forecast. Variances and updated forecasts are reviewed monthly with the Xcel Energy Financial Council. Generally speaking, it is expected that each business area do their best to manage to its approved budget levels.

Q. HOW DOES THE COMPANY'S NON-OUTAGE O&M BUDGET PROCESS AND GOVERNANCE COMPARE TO INDUSTRY PRACTICE?

A. Based on the experience of our financial staff with other companies, and our interactions with other companies within and outside of the utility industry, we believe our budget process and governance is consistent with the financial governance in practice for large companies in the United States. The five-year planning horizon, annual budget cycle, monthly forecasting process, and corporate oversight are typical elements of a well-controlled budgeting and financial governance process.

Q. WHAT IS THE COMPANY'S NON-OUTAGE O&M BUDGET FOR THE 2020 TEST YEAR?

A. As shown in Table 7 below, our 2020 test year non-outage O&M expenses are budgeted at $250.3 million, lower than our actual 2018 actual costs by

$4.4 million, or 1.7 percent. This represents a 0.9 percent average annual decrease over the two-year period.

Table 7
Nuclear Operations Non-Outage O&M Costs
($ in millions)

$ in millions	2016 Actual	2017 Actual	2018 Actual	2019 Fcst	2020 Test Year Budget	2021 Test Year Budget	2022 Test Year Budget	Avg Chg per Year 2016 to 2018	Avg Chg per Year 2018 to 2020	Avg Chg per Year 2016 to 2022
Workforce Costs										
A. Internal Labor	$ 143.6	$ 139.2	$ 135.1	$ 135.9	$ 139.4	$ 143.2	$ 146.9	-3.0%	1.6%	0.4%
B. External Labor (Contractors & Consultants)	31.7	23.3	27.9	28.1	19.9	25.4	22.6	-3.3%	-14.3%	-3.1%
C. Security	34.0	33.0	31.2	31.2	31.1	30.1	30.4	-4.2%	-0.2%	-1.8%
Subtotal Workforce Costs	209.3	195.4	194.3	195.2	190.4	198.7	199.8	-3.6%	-1.0%	-0.7%
Non-Workforce Costs										
D. Materials & Chemicals	18.0	13.7	15.4	11.8	13.4	13.4	13.3	-5.6%	-4.9%	-3.6%
E. Employee Expenses	3.5	3.2	3.3	3.2	3.5	3.5	3.5	-2.7%	3.2%	0.1%
F. Nuclear-related fees	35.8	34.1	34.0	36.8	37.1	37.5	37.9	-2.5%	4.5%	1.0%
G. Other	6.0	6.5	7.7	6.5	5.9	5.9	6.0	13.4%	-12.0%	0.7%
Subtotal Non-Workforce Costs	63.2	57.6	60.4	58.3	59.9	60.2	60.7	-2.0%	-0.3%	-0.6%
Total Non-Outage O&M	**$272.5**	**$253.0**	**$254.7**	**$253.5**	**$250.3**	**$258.9**	**$260.5**	**-3.2%**	**-0.9%**	**-0.7%**

Q. HOW ARE THE COMPANY'S LONG-TERM NON-OUTAGE O&M COSTS TRENDING?

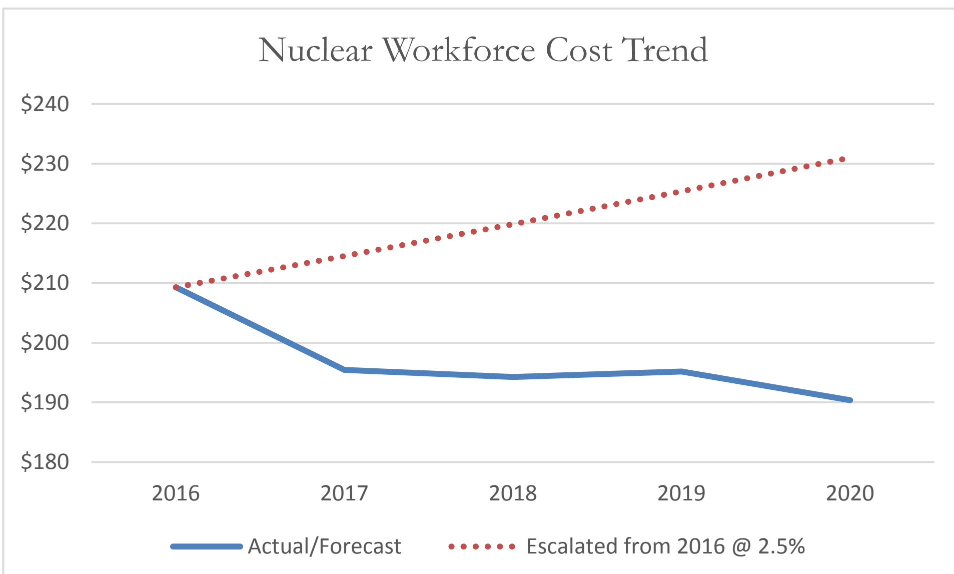
A. From 2016 through the 2022 budget, our non-outage O&M expenses are decreasing by an average of 0.7 percent annually. The calculated percentage changes by year, and average annual percentage changes over various two- and four- year periods, for non-outage O&M expenses is attached as Exhibit___(TJO-1), Schedule 4.

However, these expenses decreased by an average annual rate of 3.2 percent per year from 2016 to 2018, and are decreasing by an average of 0.9 percent per year from 2018 to 2020. In those same periods, non-outage workforce costs decreased by an average of 3.6 percent per year in 2016-2018 and are declining by 1.0 percent per year from 2018-2020. Non-workforce costs (primarily materials and fees) decreased by an average of 2.0 percent per year in 2016-2018 and are projected to decrease 0.3 percent per year in 2018-2020.

Q. WHAT IS DRIVING THESE TRENDS?

A. The decrease in total non-outage costs since 2016 has been primarily driven by a drop in overall workforce expenses and material costs. In 2017, Nuclear saw improvements from its work with external consultants and INPO using a systematic review of the organization and utilization of products jointly developed by the nuclear industry, NEI, and INPO. In 2016, industry executives, INPO, and NEI aligned on an initiative, "Delivering the Nuclear Promise" (DNP), which I discuss earlier in my testimony, to both improve performance and reduce operating costs across the industry. Over a two-year period, the DNP initiative published sixty-four (64) Efficiency Bulletins (EB) that were each sponsored by an industry executive and co-approved by NEI and INPO. Each EB was also prioritized for implementation based on the relative industry wide impact. The expectation was for Xcel Energy Nuclear to implement all required Efficiency Bulletins (red and blue priority) and implement the optional bulletins (green priority) where it made sense. The 2019 Forecast and 2020 Budget include decreasing non-outage labor costs as the cost management effort under the project will continue throughout 2019 and into 2020, primarily related to DNP EB 17-23 "Transform the Maintaining the Plant Organization," which I discussed previously. Our work has focused on process development and refinement and the integration of technology to achieve efficiencies. Focused improvement of process as well as behaviors has the benefit of driving down costs while at the same time improving plant performance. In addition to the strides we've made in managing employee labor costs, we've significantly reduced security contractor costs as well. In 2017-2018 we made innovative staffing changes, in 2018-2019 we saw staffing reductions from capital strategy improvements at Monticello, and we expect to see similar savings from our Prairie Island capital project implemented in the final quarter of 2020, with full annual savings in 2021. In the Figure below, Nuclear workforce costs from 2016 to 2020 are compared to a more normal trendline beginning with 2016 actual workforce costs escalated at 2.5% per year through 2020. Figure 2 below shows a savings of about $40 million over that four-year period.

Figure 2



A review of total O&M costs over the past 9 years further demonstrates the Company's success in O&M reduction. We had O&M costs of $302 million in 2011. If we had escalated the $302 million in 2011 at a conservative rate of 2% per year, we would predict $361 million in O&M costs in 2020. This would total to cumulative O&M spend of about $3 billion over the 9 years from 2011-2020. Instead, we spent only $2.92 billion over that 9-year period, saving about $80 million. The Company's proposed total O&M spend for Nuclear in 2020 is $300 million, which is essentially the same level as 2011.

Further, our overall total non-outage O&M costs in 2020 are actually budgeted to be less than actual 2018 levels. This is consistent with the Xcel Energy's long-term strategic goal of "bending our cost curve" and keeping costs flat on an average annual basis.

Q. DO YOU ANTICIPATE THAT NUCLEAR WILL BE ABLE TO CONTINUE TO ACHIEVE INCREMENTAL O&M REDUCTIONS?

A. In light of the changes already made to reduce O&M, and the impact of governmental fees, the nuclear group likely will not have substantial ability to make additional significant reductions in the future.

Q. WHAT CHANGES HAS THE COMPANY MADE TO REDUCE O&M?

A. As I mentioned earlier in my testimony, the two main drivers of cost reductions to date involved centralizing support functions at the fleet level. This provides the opportunity to compare processes and select best practices, utilize resources across peaks at both sites, and reduce supervision. The non-outage support functions include Security, Performance Improvement, Emergency Preparedness, Nuclear Oversight, Regulatory Services, Engineering, and Projects.

We also have centralized responsibility for outage duration and cost improvements. Our efforts with respect to outages have included negotiation of longer-term contracts at reduced prices with major outage vendors, along with other groups within Xcel Energy, for greater purchasing power. These contracts cover refueling, generator and turbine services, and outage supervision and craft. We have also benchmarked our outage duration and cost against the industry, and have implemented some of the specific techniques at the Company that we observed while visiting other sites. Our submission of risk-based LARs will lower costs by reducing the frequency of inspections required during outages.

Q. HOW DOES THE TREND IN NUCLEAR-RELATED FEES IMPACT THE COMPANY'S ABILITY TO CONTINUE TO REDUCE NUCLEAR O&M?

A. The ongoing increases in certain nuclear-related fees presents a significant obstacle to additional O&M reductions. Total O&M from 2016 to 2022 is declining, while government-based payments, which include certain O&M costs like NRC fees and state emergency preparedness fees, are rising and/or mandated by government. As discussed below, the Company has little or no control over these government-imposed costs.

Q. DO YOU HAVE ANY CONCLUDING REMARKS ON THE COMPANY'S ABILITY TO CONTINUE TO REDUCE NUCLEAR O&M COSTS DURING THE PERIOD COVERED BY THIS RATE REVIEW?

A. Yes. While we will continue to cultivate an organization with a competitive mindset and continuous improvement culture, we must always balance safety, reliability, and cost simultaneously. With this background in mind, and the magnitude of reductions we've achieved over the last several years, we anticipate that the rate of cost reductions will be much slower going forward than in the last few years, and will offset inflationary increases at best.

B. Non-Outage O&M Budget Categories – 2020 Test Year

1. Employee Labor

Q. PLEASE DISCUSS THE NON-OUTAGE EMPLOYEE LABOR INCLUDED IN THE NUCLEAR BUSINESS UNIT'S O&M TEST YEAR.

A. Non-outage employee labor expenses included in the test year are approximately $139.4 million and include all regular pay for Nuclear employees, including base pay, premium pay, and overtime consistent with applicable bargaining agreements. It does not include annual incentive pay.

Q. WHAT ARE THE MAJOR TRENDS IN EMPLOYEE LABOR OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As shown in Table 7 above, internal labor costs decreased 3.1 percent from $143.6 million in 2016 to $139.2 million in 2017, and decreased another 2.9 percent to $135.1 million in 2018. Beginning in 2019, internal labor costs are forecast to increase much less than the normal merit increase, with a 0.6 percent increase forecasted to $135.9 million, and are budgeted to increase by 2.6 percent to $139.4 million in 2020.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. Labor decreased over the period 2016-2018 mainly due to a reduction of headcount achieved through cost management initiatives, with the majority of reductions coming from the consolidation of support functions at the fleet level, rather than at the plant level.

Increases observed in labor beginning in 2019 are driven by merit pay increases offset by continuing cost management initiatives and, beginning in 2020, our plan to increase headcount through the addition of new, multi-skilled union positions that are designed to streamline work processes at the plants.

Q. PLEASE EXPLAIN THE DIFFERENCE IN EMPLOYEE LABOR FROM 2018 ACTUAL COSTS TO THE 2020 TEST YEAR BUDGET IDENTIFIED ABOVE IN TABLE 7.

A. The labor budget in 2020 is increasing $4.3 million or 3.2 percent from 2018 levels, an annual average increase of 1.6% per year. The majority of labor cost increases from 2018 to 2020 are merit pay increases earned by employees at an average of 3.0 percent in each of those years. The average headcount in 2020 is budgeted to increase by about 17 FTE over year-end 2018 levels.

Q. PLEASE DESCRIBE THE CHALLENGES THE NUCLEAR ORGANIZATION FACES WITH RESPECT TO MAINTAINING ITS EMPLOYEE WORKFORCE.

A. Maintaining a skilled and engaged workforce is one of the Company's top priorities as it impacts cost, performance, and safety. It remains a significant challenge to recruit and retain technically experienced nuclear employees. The compensation levels necessary to recruit and retain experienced nuclear employees is ever increasing based on the limited number of nuclear plants in the United States and the highly competitive practices employed by other nuclear companies in pursuit of the same experienced personnel.

The supply of possible nuclear employees is becoming more limited as well. With the industry being more than 50 years old, many experienced nuclear personnel are well along in their careers and will be in a position to retire in the next five to ten years.

Further, the lack of clear long-term public policy support for nuclear energy in the United States is limiting the entry of new employees into the industry. We are doing our part to attract new, younger employees to nuclear through our internship, "pipeline," and rotational programs, particularly in the operations and engineering areas.

Finally, given the nuclear industry's openness in sharing issues and their resolution, plants with new performance issues are able to identify and recruit personnel who have worked at other plants who have successfully resolved issues. Our plants are performing at historic levels, which makes our employees desirable candidates to other utilities that are seeking to improve their performance, as our employees have demonstrated ability to operate successful plants. These other companies are offering signing bonuses and retention incentives to attract and retain experienced employees from other nuclear companies. We need to ensure that we are providing adequate pay, training, and opportunities to attract and retain the caliber of workers that we need to continue to operate at our current high level. Talent development, including fostering a culture of continuous improvement, is a constant focus for the Nuclear organization, and an essential element to achieve our performance objectives for our stakeholders.

Q. IN PAST RATE CASES, THE COMPANY HAS SOUGHT RECOVERY OF THE NUCLEAR EMPLOYEE RETENTION PROGRAM COSTS. IS THE COMPANY SEEKING TO RECOVER THE COSTS OF THIS PROGRAM IN THIS CASE?

A. No. To limit the number of contested issues, we are not seeking recovery of Nuclear retention program costs in this case.

Q. DOES THE COMPANY PLAN TO CONTINUE TO USE A RETENTION PROGRAM?

A. Yes. However, because we've achieved many of the goals the program was designed to attain, use of the program will be limited. This program has been successful; over the last few years, we have built a succession plan that will ensure that Nuclear continues to have employees with the necessary skills to safely and efficiently operate our plants going forward. As a result, we have scaled back the scope of our retention plan, and deploy it only in specific circumstances on a case-by-case basis.

We have successfully reduced turnover, and as discussed previously, overall performance at both plants has continued to improve, resulting in record high performance in safety, reliability, and capacity. We have now incorporated other retention provisions in our employee agreements to help attract and retain qualified personnel and have taken other steps to attract and retain the right skilled workforce at our plants; including the planned development of new, multi-skilled union positions. The benefits of maintaining our employee base are clear both on an operational basis and a cost basis as we avoid the costs related to recruiting and training replacement employees or hiring additional contractors to fill the gaps.

2. Non-Employee Contractors and Consultants

Q. PLEASE EXPLAIN THIS BUDGET CATEGORY.

A. Contractors can be a cost-effective resource in some circumstances. We use contract labor (managed by site employees) for peak projects. Also, where we are unable to complete permanent hires to meet certain needs (or find it uneconomic to do so), we bring in contractors to supplement our ongoing work and fill in gaps until permanent positions can be filled. Contractors are used primarily to perform O&M project studies, engineering support and design, preventative maintenance studies, and regulatory project studies. We find the specialized expertise that contractors bring cheaper to buy than to qualify and maintain internally. Examples of specialty expertise include HVAC (heating, ventilation and air conditioning), heavy equipment servicing, certain engineering analysis, and reactor core fuel design.

Q. WHAT ARE THE MAJOR TRENDS IN NON-EMPLOYEE CONTRACTORS AND CONSULTANTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 7 above shows, contractor/consultant costs decreased from $31.7 million in 2016 to $23.3 million in 2017, increased to $27.9 million in 2018, and are forecasted to increase slightly to $28.1 million in 2019. For 2020, costs are budgeted to decrease substantially to $19.9 million.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. There were a number of larger projects and other one-time, or unusual activities, in 2019 that required contract labor at both plants. At Monticello, those included 10-year preventative maintenance; while at Prairie Island, work on the diesel generator and cooling towers required additional contract labor. In addition, cost management initiatives related to reduction of contractor use that were not fully implemented in 2019 will lead to further reductions in 2020. We group Internal Labor and External Labor together intentionally as Workforce Costs because when significant attrition occurs, we may need to hire external labor to get work accomplished. Conversely, when attrition slows we may not need to use external help as much as we've done in the past.

3. Security Costs

Q. WHAT ARE SECURITY COSTS?

A. Security costs reflect the contract labor workforce we procure to meet the security post requirements of the NRC along with the Xcel Energy labor costs necessary to provide governance and oversight of the contract security force. Posts are manned 24 hours per day / 7 days a week. This has resulted in Security being the largest single functional workforce in the Nuclear organization. The number of security officers manning each post is based on coverage requirements set by the NRC. The specific logistics of each plant must be mapped to the NRC's requirements, and coverage levels must be maintained at all times. If any unusual security issues are noted, additional "compensatory" posts may be required on a temporary basis until a permanent security remedy can be designed and implemented, subject to NRC approval. The Security workforce item excludes the internal security management team that oversees the contract workforce. (The internal team costs are included in the Internal Labor line item.) The workforce costs are paid to an outside security firm based on the number of officers required per post and the contracted labor and benefit rates agreed to with the Company.

The NRC's security requirements under our operating license are quite extensive and unique to nuclear plants. Our plants must file a security plan that addresses those requirements, including provisions for various contingencies (such as hostile threats or radiological emergencies) and compensatory actions when appropriate. The security plan has to provide a satisfactory response to real and potential threats, and must be able to operate concurrent with a nuclear radiological emergency should that occur.

The NRC requires self-assessment of security effectiveness, and also performs inspections. Issues found from either self-assessments or inspections must be remedied initially through compensatory measures, and followed up with a longer term permanent remedy. Our goal is to comply with requirements but seek cost-effective means to do so, which can involve capital modifications to reduce compensatory measures where feasible.

Q. WHAT ARE THE MAJOR TRENDS IN SECURITY COSTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 7 above shows Security Contractor costs have decreased each year, decreasing by 3 percent in 2017, 5 percent in 2018, and forecasted to remain relatively flat in 2019 and 2020.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. As mentioned previously, a number of cost management initiatives have been undertaken related to security contractor costs: in 2016-2018 we implemented innovative staffing changes; in 2017-2018 we realized O&M benefits at Monticello related to our capital security strategy project and we expect to see similar benefits from our Prairie Island capital security project beginning in the last quarter of 2020. Table 8 below shows the major components that are driving the decreases in security costs from actual 2018 to test year 2020.

Table 8

Security Increase Breakdown:

2018 Actuals to 2020 Test Year *($ in millions)*

2018 Actual Security Contractor Costs	**$31.2**
[PROTECTED DATA BEGINS…	
	...PROTECTED DATA ENDS]
2020 Test Year Security Contractor Costs	**$31.1**

The trend toward consistent increases in security costs over time is expected to return in the future as the impact of the cost management initiatives will no longer be available to offset the annual merit increases of the officers. We expect a continuing national concern over the enhanced security of nuclear plants, not only to provide protection for external events post-Fukushima, but also for hostile threats to plant and public safety. Of course, with a mindset toward continuous improvement, we will stay abreast of industry and technological advances in this area for any opportunities to reduce costs and be more effective.

4. Materials Costs

Q. PLEASE EXPLAIN THIS BUDGET CATEGORY.

A. Materials costs include tools, equipment and other resources to maintain and operate our nuclear generating facilities. They include items such as chemicals used in the nuclear generation process, radiological supplies, overhaul supplies not meeting capitalization thresholds, computer supplies, intake screen parts, boiler fuel oil, and ammunition used by on-site security personnel. The materials costs included in O&M are generally those consumed in the operating process or small in amount, and are in addition to materials capitalized in construction projects.

A key element of materials for nuclear utilities is the regulatory scrutiny and rules for equipment components and parts in use at our plants. Replacement and repair parts must meet regulatory qualification requirements for safety tolerances. Given the fact that most nuclear plants are 40+ years old, the original equipment manufacturers (OEM) may no longer be in business or produce the same components. The availability of replacement OEM components from vendors, or the time needed to qualify new components as acceptable, can create plant licensing basis and shutdown risks due to non-conformance with requirements.

Q. WHAT ARE THE MAJOR TRENDS IN MATERIALS COSTS OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 7 above shows, materials costs varied between 2016-18 from $13.7 million to $18.0 million. We are forecasting/budgeting lower costs of about $11.8 million to $13.4 million in 2019 and 2020.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. With consistent plant operation of three nuclear units, many of the chemicals, supplies, and inventoried parts and materials needed to operate our three nuclear units remain constant over time and represent a base level of cost that does not fluctuate notably.

The increase from 2019 to 2020 is largely due to diesel generator work scheduled for Prairie Island in 2020.

5. *Employee Expenses*

Q. PLEASE DISCUSS WHAT EMPLOYEE EXPENSES ARE INCLUDED IN THE NUCLEAR OPERATION BUSINESS UNIT'S 2020 TEST YEAR O&M BUDGET.

A. Employee expenses are comprised mainly of the costs for Nuclear employees to travel both within and outside the Company's service territory for business reasons. The most common need for travel is for: staff travel (by car) between plant sites and fleet headquarters to provide support and oversight; meetings with regulatory and oversight agencies such as NRC and INPO; meetings and initiatives with industry groups such as NEI, EEI, and USA; performing industry benchmarking with and quality reviews (including INPO) for other nuclear utilities; and vendor oversight for quality assurance (which can involve international travel). We critically review employee expenses and are working hard to optimize the benefit of such travel in consideration of the associated costs.

Q. WHAT ARE THE MAJOR TRENDS IN NUCLEAR EMPLOYEE EXPENSES OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 7 above shows, employee expenses fluctuated from 2016-2018 between $3.2 million and $3.5 million. Beginning in 2020, expenses are anticipated to increase to $3.5 million.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. A base level of employee expenses is necessary for staff travel between sites, as part of interacting with regulators (NRC) and industry oversight functions

(INPO), and to participate in industry groups and initiatives. The base level can fluctuate upward with more fleet headquarters staff or cross-site support, with increased levels of regulatory and industry oversight activity, and with increased participation in industry groups and initiatives.

As noted above, as part of our overall cost management and best practices initiatives, nuclear has adopted a "one fleet" approach with respect to support functions. As a result, we anticipate slightly more staff travel between sites for this support in 2020 and beyond. Providing this cross-site support has improved performance and reduced our reliance on contractors – one of our strategies as I discussed earlier, when we can supplement site resources with help from our other sites. We have also found targeted travel to visit our stakeholders and regulators to anticipate, understand, and potentially influence regulation is helping improve our cost and performance, so we intend to increase the level of this activity in 2020 and beyond.

6. Other Expenses

Q. PLEASE DISCUSS WHAT OTHER EXPENSES ARE INCLUDED IN THE NUCLEAR OPERATION BUSINESS UNIT'S 2016 TEST YEAR O&M BUDGET.

A. "Other" O&M expenses are comprised mainly of information technology and support costs (such as software licensing and hardware maintenance), utility costs (i.e. electricity and gas used by the sites), rents (for equipment and facilities), facility and site maintenance costs, fleet vehicle transportation costs, permits, office supplies and printing costs.

Q. WHAT ARE THE MAJOR TRENDS IN OTHER O&M EXPENSES OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Table 7 above shows, Other O&M Expense costs were increased from $6 million in 2016 to $7.7 million in 2018. The forecast show costs dropping again to 2017 levels in 2019, and budgeted costs in 2020 decrease yet again to just under $6 million. Approximately $1.1 million of costs classified as "other" in 2018 represented some unusual items at Monticello such as $600,000 renovation of 40- and 50-year old bathrooms/showers (24) in two buildings serving approximately 530 workers; $120,000 for carpeting in the training center, and $360,000 for site paving repairs. Absent those unusual items, costs in the "other" category have remained, and will continue to remain, relatively constant.

7. Nuclear-Related Fees

Q. WHAT ARE INCLUDED IN NUCLEAR-RELATED FEES?

A. Nuclear fees include industry specific fees and dues. Fees are assessed by the industry's Federal regulatory oversight agency (NRC), by the industry's operational oversight organization (INPO), by governmental emergency preparedness and management agencies (Federal Emergency Management Agency (FEMA) and various state agencies), and consistent with agreements with the Prairie Island Indian Community (PIIC). Dues are assessed by various industry organizations and groups. Table 9 depicted below lists out the various components of Nuclear Fees and the changes by year.

Table 9

Nuclear Fees

$ in millions	2016 Actual	2017 Actual	2018 Actual	2019 Fcst	2020 Test Year Budget	2021 Test Year Budget	2022 Test Year Budget	Avg Chg per Year 2016 to 2018	Avg Chg per Year 2018 to 2020	Avg Chg per Year 2016 to 2022
NRC	19.0	17.1	18.0	19.3	19.2	19.4	19.6	-2.5%	3.4%	0.6%
FEMA / State EP	6.3	6.2	6.6	7.6	7.6	7.7	7.8	2.6%	7.7%	3.8%
INPO	3.2	3.0	3.0	3.1	3.1	3.1	3.2	-2.2%	1.1%	0.0%
EPRI	2.8	2.4	2.4	2.4	2.6	2.6	2.7	-5.6%	2.6%	0.0%
PI Indian Community	2.5	3.1	1.9	2.5	2.5	2.5	2.5	-7.5%	16.7%	3.1%
NEI & Other Industry Groups	2.1	2.3	2.1	1.9	2.1	2.1	2.2	1.7%	0.8%	1.2%
Total Nuclear Fees/Dues	35.8	34.1	34.0	36.8	37.1	37.5	37.9	-2.4%	4.5%	1.0%

Q. WHAT ARE THE MAJOR TRENDS IN NUCLEAR-RELATED FEES OVER THE LAST THREE YEARS AND THROUGH THE TEST YEAR?

A. As Tables 7 and 9 above show, Nuclear Fees decreased from $36 million in 2016 to $34 million in 2017 and 2018; are forecasted to increase to nearly $37 million in 2019; and are budgeted to slightly increase to about $37.1 million in 2020. Overall, fees and dues in the test year 2020 are increasing an average of 4.5 percent per year from actual 2018 levels.

Q. WHAT ARE THE DRIVERS BEHIND THESE TRENDS?

A. Both NRC fees and FEMA/state emergency preparedness (EP) fees have fluctuated in various years, with NRC fees accounting for most of the decrease overall in 2016 to 2017 and the 2018 to 2019 increase. Fluctuations in other categories create slight changes in the overall fees. PIIC fees are constant at an average of $2.5 million per year. The 2020 increase is driven by higher fees for NRC and FEMA/EP.

Q. PLEASE EXPLAIN THE DIFFERENCE IN NUCLEAR-RELATED FEES FROM 2018 ACTUAL COSTS TO THE 2020 TEST YEAR BUDGET IDENTIFIED ABOVE IN TABLES 7 AND 9.

A. Two areas are driving increases in fees and dues from 2018 to 2020: NRC fees and FEMA/state emergency preparedness fees. All other fees and dues are increasing an average of 2.7 percent or less annually. I will explain the drivers for the larger changes in the next set of questions in my testimony.

Q. PLEASE EXPLAIN THE VARIATIONS IN NRC FEES OVER THE YEARS, IN PARTICULAR THE INCREASE IN 2020 FROM ACTUAL 2018 LEVELS.

A. NRC fees consist of two components, NRC Reactor fees which are fixed fees assessed on a per-reactor basis, and NRC Inspection fees, which vary based on work the NRC does for each operator. NRC Reactor fees are based on total NRC budgeted resources less the costs billed for inspections (which are recovered through NRC Inspection fees) and allocated equally amongst total operating reactors under the NRC's purview. Table 10 below summarizes the changes in these two components from 2018 to 2020.

Table 10
Nuclear Fees – NRC

$ in millions	2016 Actual	2017 Actual	2018 Actual	2019 Fcst	2020 Test Year Budget	2021 Test Year Budget	2022 Test Year Budget	Avg Chg per Year 2016 to 2018	Avg Chg per Year 2018 to 2020	Avg Chg per Year 2016 to 2022
NRC Reactor Fees	14.4	13.2	13.6	14.8	14.8	14.9	15.1	-2.7%	4.2%	0.8%
NRC Inspection Fees	4.6	3.9	4.4	4.5	4.4	4.5	4.5	-1.6%	0.7%	0.0%
Total NRC Fees	19.0	17.1	18.0	19.3	19.2	19.4	19.6	-2.5%	3.4%	0.6%

Q. PLEASE EXPLAIN THE VARIATIONS IN NRC REACTOR FEES.

A. The variations in NRC Reactor fees are dependent on total NRC budgeted resources and the offsetting costs billed for inspections. The 8 percent decrease in 2017 in NRC Reactor fees from 2016 is primarily due to the reduction of total NRC budgeted resources. This reduction was attributable to a need for fewer resources to reduce the NRC's licensing actions backlog and to conduct other work, such as the Fukushima-related rulemaking.

Because NRC's budgeted resources in 2018 did not change from 2017 levels and the number of total operating reactors remained at 99, NRC Reactor fees in 2018 only increased 3 percent. In 2019, NRC's budgeted resources stayed relatively consistent with 2018 levels despite the reduction in total operating reactors and inspections due to the shutdown of the Oyster Creek reactor at the end of 2018. As a result, the per-reactor fees increased almost 9 percent (one fewer reactor over which to spread the NRC costs). As the NRC continues to maintain its budgeted resources at 2017 levels in 2019 despite the reduction in operating reactors, per-reactor fees are projected to continue to increase.

The 2020 test year budget for NRC Reactor fees assumes that the NRC continues to maintain its budgeted resources at 2017 levels despite the reduction in operating reactors and their associated inspections and as such per-reactor fees will increase as each fiscal year progresses. The NRC's fiscal year ended September 30. We assume that reactor fee levels will increase for the fourth quarter of 2019, and again in the fourth quarter of 2020, at 1 percent each year.

We base our assumed level of 1 percent annual increases in reactor fees on the best information available, considering NRC communications, history and experience. However, the NRC's assessed reactor fees are intended to cover all of their agency costs other than those funded by inspection fees, and when NRC budgets include unique drivers (such as one-time programs like Fukushima, or expected staffing increases), past history is not necessarily predictive of future fee changes. Further, planned shutdowns of Pilgrim and Three Mile Island reactors during FY 2019 may increase the per reactor fee as the total allocable licensed power reactors would decrease from 98 in 2019 to only 96 in 2020.

Q. PLEASE EXPLAIN THE TREND IN NRC INSPECTION FEES FROM 2018 TO THE TEST YEAR.

A. The 2020 test year fees for NRC inspections are budgeted to continue at the current levels we are being billed in 2019. This level represents an annual average increase from actual inspection fees in 2018 of only 0.7 percent. Our current level of inspection billings in 2019 is slightly higher than 2018 actuals and we project the same level of inspections to continue into 2020. That said, because the NRC may conduct inspections in 2020 that have not yet been scheduled or requested, the 2020 inspection schedule could possibly include more inspections than current 2019 levels.

Q. DOES THE COMPANY SEE ANY OPPORTUNITY TO DECREASE NRC FEES?

A. Potentially. While the NRC fees are largely beyond the Company's control, the Company will work with industry and oversight agencies such as NRC and INPO to leverage advances in technology to streamline certain processes. If such measures gain acceptance in the future, they could possibly lower the cost of NRC and INPO oversight.

Q. PLEASE EXPLAIN THE VARIATIONS IN FEMA/EP FEES, IN PARTICULAR THE INCREASE EXPECTED FROM 2018 ACTUALS TO 2020.

A. There are four main elements of emergency planning fees: one at the national level, Federal Emergency Management Agency (FEMA); and three at the state and local levels, Minnesota Department of Public Safety (Homeland Security and Emergency Management), Wisconsin Radiological Emergency Planning Program, and Pierce County in Wisconsin (Office of Emergency Management). We base our assumed level of annual increase/decrease in these costs on the best information available, which typically includes communications directly from the applicable agency, historical rates of increase, and any knowledge of unique drivers such as one-time programs or expected staffing increases. The 2020 increase can be summarized as shown in Table 11 below.

Table 11

Nuclear Fees – FEMA/Emergency Preparedness (EP)

$ in millions	2016 Actual	2017 Actual	2018 Actual	2019 Fcst	2020 Test Year Budget	2021 Test Year Budget	2022 Test Year Budget	Avg Chg per Year 2016 to 2018	Avg Chg per Year 2018 to 2020	Avg Chg per Year 2016 to 2022
FEMA	1.2	1.1	1.1	1.1	1.2	1.2	1.2	-5.1%	6.8%	0.9%
Minnesota EP	4.1	4.3	4.6	5.8	5.4	5.5	5.5	5.6%	10.1%	5.5%
Wisconsin EP	0.9	0.7	0.9	0.6	0.9	0.9	0.9	0.6%	5.3%	2.3%
Pierce County WI EP	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-5.1%	3.9%	-0.4%
Total Nuclear Fees/Dues	6.3	6.2	6.6	7.6	7.6	7.7	7.8	2.6%	7.7%	3.8%

The primary driver of the increase seen in 2019 is the $1.2 million increase in Minnesota EP fees. The increase in Minnesota EP fees are driven by additional regulatory rules and training requirements for emergency planning and preparedness. The NRC requires communities supporting nuclear plants to perform regular drills to practice preparedness for hostile actions (such as an attack on the plant) and responses to external events (such as flooding or tornado threats).

The current budget set by the Minnesota Department of Public Safety (Homeland Security and Emergency Management) is $5.4 million for the state budget period of July 1, 2019 through June 30, 2020. This is $1.2 million higher than the final state bill for the period of July 1, 2017 through June 30, 2018. The budget level provides is our best indication of the amount of fees the Department anticipates billing for that year.

Q. PLEASE DESCRIBE THE PIIC FEES.

A. Minnesota legislation passed in 2003 (Statute 216B.1645, subdivision 4, *Settlement with Mdewakanton Dakota Tribal Council at Prairie Island*) states in part:

> The commission shall approve a rate schedule providing for the automatic adjustment of charges to recover the costs or expenses of a settlement between the public utility that owns the Prairie Island nuclear generation facility and the Mdewakanton Dakota Tribal Council at Prairie Island, resolving outstanding disputes regarding the provisions of Laws 1994, chapter 641, article 1, section 4. The settlement must provide for annual payments, not to exceed $2,500,000 annually, by the public utility to the Prairie Island Indian Community …

Under this statutory provision, the Company paid the PIIC various levels of fees, depending on their nature as recurring or non-recurring, under the settlement agreement.

The average payment since 2016 has been $2.5 million and is expected to remain at that level going forward. As noted in Table 9 above, $3.1 million was booked in 2017; and as a correction, only $1.9 million was booked in 2018. This was a one-time accounting error, and does not reflect a change in fees.

Q. HOW DO NUCLEAR'S OVERALL O&M COSTS COMPARE TO OTHER COMPANIES IN THE INDUSTRY?

A. As discussed above, the total O&M costs at Prairie Island and Monticello continue to compare favorably to other facilities across the United States. The EUCG charts set forth at Schedule 5 provides comparison charts for total operating costs in 2018 for single unit sites like Monticello and dual unit sites like Prairie Island. Total operating costs include all of our O&M, including non-outage and outage. This data is provided by the EUCG based on surveys of industry companies, including the Company. These comparisons show the cost of our plants to be lower than most plants on a total dollar basis for operating costs.

C. Multi-Year Rate Plan Non-Outage O&M Costs

Q. WHAT IS THE LEVEL OF O&M EXPENSE NUCLEAR SEEKS TO RECOVER FOR THE 2021 AND 2022 PLAN YEARS?

A. As shown in our 2021 and 2022 supporting information, provided in Volume 6 of our Initial Filing, Nuclear is forecasting changes in its non-outage O&M expenses for Plan Year 2021 in the following areas:

- An increase in labor of $3.8 million (2.7 percent) due largely to annual merit increases in base pay.
- An increase in external labor (including Security) of $4.5 million (8.8 percent) due to 10-year inspections, aging management, surveillances and other maintenance work in

Nuclear is also forecasting changes in its non-outage O&M for Plan Year 2022 in the following areas:

- An increase in labor of $3.7 million (2.6 percent) due largely to annual merit increases in base pay
- A decrease in external labor (including Security) of $2.5 million (4.6 percent) for additional cost management initiatives not fully implemented in prior years

These forecasted increases for 2021-2022 are comparable with the relatively consistent level of annual increases in merit pay and nuclear fees for 2020, as discussed earlier in my testimony.

V. PLANNED OUTAGE O&M BUDGET

A. Overview and Trends

Q. HAS THE COMPANY MADE ANY CHANGES TO HOW IT HANDLES OUTAGES SINCE ITS LAST RATE CASE?

A. Yes. As noted above, as part of the cost management and best practices initiatives, Nuclear has centralized outages on a fleet-wide basis under a single leader. When planning outages, the Company targets a desired duration and cost per day for each outage. In addition, the Company has entered into a number of long-term contracts with its outage contractors in order to negotiate better prices for outage services. Also, during the 2018 outage at Prairie Island Unit 1, we implemented a new fuel design that will allow that unit to operate for 24 months between refueling instead of 18 months. The same fuel design will be implemented at Prairie Island Unit 2 during the fall 2019 outage.

Q. HAS THE COMPANY SEEN ANY RESULTS FROM THESE CHANGES?

A. Yes. Since centralizing the outage function, both the duration, total outage O&M costs and cost per day of outages has declined, as seen below in Table 12 below.

Table 12

Planned Outage Cost per Day

($ in millions)

Unit	**PI Unit 1**	**MT**	**PI Unit 2**	**PI Unit 1**	**MT**	**PI Unit 2**	**PI Unit 1**
Period	**Fall 2016**	**Spring 2017**	**Fall 2017**	**Fall 2018**	**Spring 2019**	**Fall 2019**	**Fall 2020**
Outage Duration (Days)	37	30	38	35	30	[Protected Data Begins… …Protected Data Ends]	[Protected Data Begins… …Protected Data Ends]
Total Outage O&M Cost	$ 37.6	$ 36.7	$ 32.1	$ 33.2	$ 33.40	[Protected Data Begins… …Protected Data Ends]	[Protected Data Begins… …Protected Data Ends]
Outage Cost per Day	$ 1.016	$ 1.223	$ 0.845	$ 0.949	$ 1.113	[Protected Data Begins… …Protected Data Ends]	[Protected Data Begins… …Protected Data Ends]

In addition, the extension of the refueling schedule at Prairie Island Units 1 and 2 is anticipated to save between $60-$70 million over the next 15 years by eliminating two planned outages over the life of the two units.

Q. HOW ARE THE COMPANY'S LONG-TERM PLANNED OUTAGE O&M COSTS TRENDING?

A. Table 13 below shows the trend for Outage O&M for our nuclear plants from 2016-2020.

Table 13

Net Nuclear Planned Outage O&M Costs

	2016 Actual	**2017 Actual**	**2018 Actual**	**2019 Fcst**	**2020 Test Year Budget**	**Annual Avg % Change: 2018 to 2020**
Planned Outage O&M Costs - Nuclear Operations Spend	$ 38.5	$ 67.0	$ 34.5	$ 63.6	$ 33.7	
Deferral of Current Year Outage O&M Costs	$ (38.5)	$ (67.0)	$ (34.4)	$ (63.7)	$ (33.7)	
Outage O&M Amortization	$ 70.0	$ 62.9	$ 53.2	$ 50.0	$ 49.7	
Net Nuclear Outage O&M	**$ 70.0**	**$ 63.0**	**$ 53.3**	**$ 49.9**	**$ 49.7**	**-3.4%**

Overall outage spend varies by year based on whether one or two outages is performed. Prairie Island generally alternates outages for its Units 1 and 2 each year, resulting in one outage per year at that site, and in odd years (2017 and 2019) Monticello has its outage in addition to Prairie Island's. In addition, spend can be periodically skewed upward when required 5- and 10-year inspections or unusual emergent maintenance occurs.

Outage costs (on a per-outage basis) have ranged from $34 million to $38 million from 2016-2018. With an approximately 24-month amortization process for the spend between outages, that trend has resulted in a decrease in amortized outage costs from $70 million in 2016 to $63 million in 2017 and $53 million in 2018, followed by a decrease down to about $50 million in 2019 and 2020. As discussed in the next section of my testimony, the scope and therefore the cost of each outage is driven by the level of planned maintenance, inspections, emergent work, and construction projects performed during the outages each year.

It should be noted that outage spend in Table 13 above is on an annual cash flow basis for all work done on any outage being planned or performed that year. The outage spend includes pre-outage planning work that is deferred, sometimes into the next calendar year, and is then amortized along with the cost of work performed during the outage.

Q HOW DOES THE COMPANY SET THE PLANNED OUTAGE O&M BUDGET FOR THE NUCLEAR OPERATIONS BUSINESS UNIT?

A. Planned outages refer to regularly scheduled refueling outages during which we also perform off-line maintenance to the plant. The first step in developing the budget for planned outage costs is to identify the scope and schedule of refueling outages. The schedule for a planned outage in a given cycle is determined by the unit's fuel reloading needs; which, as discussed earlier in my testimony, has a target of every other year at each unit. Monticello has historically been on a 24-month fuel cycle and Prairie Island has been on a 22- to 24-month cycle. Recently, we have performed refuelings at Monticello in the spring of odd years. At Prairie Island, we have performed refuelings in the fall of even years for Unit 1 and the fall of odd years for Unit 2. This schedule is based on continuous operation of the plant, and can change depending on unplanned outages and their impact on the fuel operating cycles. The scope of a refueling outage includes recurring activities (the activities completed during every refueling outage), periodic activities (activities that occur on a defined schedule but not necessarily every refueling outage) and other one-time or special activities (such as capital projects).

The specific scope of each refueling outage is driven by both NRC license requirements (such as the plant's Technical Specifications) and industry-defined programs. Industry expert groups such as INPO, NEI and equipment owner groups provide best practices in critical equipment preventative maintenance and safety systems protection, which are key inputs to outage scope. These groups are part of the industry trends and strategies I referred to earlier in my testimony. Another set of inputs comes from plant operating and safety risk needs and reliability preventive measures for cycle-to-cycle operations. All of these activities are estimated individually and then aggregated to create the initial outage budget.

The refueling outage budget process is dynamic, with planning that remains fluid until the day the outage starts, and then adapts to emergent issues that may arise during the outage (typically based on inspections). Initial cost estimates for completion of the work are based on historical estimates, adjusted for labor or material cost changes that are known, or estimated using escalation for inflation. After initial planning, we solicit vendor bids for work scopes with performance criteria.

Activities in the refueling outage scope are controlled internally under our work order process. A work order will define the work to be completed, the resource (internal or contract) responsible to prepare for and complete the work, and the materials needed to support the work. Updated information on estimated labor and material costs are incorporated as the work order progresses through the planning process leading up to the actual refueling outage.

Planned outage budgets are reviewed in Nuclear's financial governance process, with regular (daily/weekly) reviews at the plant site, and monthly reviews through the business area and Xcel Energy corporate forecasting process.

Q. WHEN DOES THE PLANT START THE OUTAGE PLANNING PROCESS?

A. A long-range plan exists which lays out the major activities for each outage for at least six years. The detailed planning process starts two years in advance of the refueling outage and before the prior refueling outage on that same unit has been completed. As an example, as Prairie Island performs its Unit 2 outage in the fall of 2019, the scoping for the Unit 1 outage in the fall of 2020 will be nearing final completion and planning will be commenced to ensure readiness for the 2020 outage. Work performed in the previous refueling outage will help define portions of the work for that unit's next refueling outage via lessons learned for better efficiency and selection of work scope.

We continue to look for ways to improve outage performance to reduce our planned outage duration and cost. For the fall 2019 outage at Prairie Island, we are implementing some of these improvement initiatives, including scaffold design improvements and increased oversight of the efficient use of contractors.

Q. HOW DOES THE PLANT PLAN A SPECIFIC OUTAGE'S WORK SCHEDULE?

A. An overriding consideration in planning every outage is concern for plant shutdown safety and managing the unique outage configuration scenarios. The primary requirement is to ensure continuous nuclear fuel cooling when the nuclear reactor is shut down for an outage. Post-Fukushima, stakeholders have a new focus and a much more conservative perspective on safety and compliance. Accordingly, all outage work is evaluated with safety as the most important concern.

The planning process for outage work activities follows industry best practices and includes numerous planning milestones that are uniquely set for each outage. These include pre-outage work-order planning milestones, identification of major maintenance and projects, a review of scope based on the previous outage, and extensive engineering and project planning milestones. Several of the milestones will result in updated inputs into the final outage budget development. Although efforts are made to maintain budget, scope changes do occur and emergent issues due to plant needs or regulatory requirements arise that require deviations from budget to ensure safety, compliance and reliability are not compromised.

For the non-outage and capital work, we review the requirements for those activities and evaluate how the necessary work will most efficiently fit into the outage schedule. Work activities that can safely be done on-line are performed outside of outage timeframes to minimize the outage duration and cost. There is always some risk of an unintended consequence when performing work while a unit is on-line that could result in unit shutdown. We also consider that doing the work while the unit is shut down can improve the available access to plant equipment and afford the opportunity to reduce radiation doses to the workers while accomplishing the work. All of these factors are considered in developing an outage's work plan.

Q. HOW DOES THE COMPANY PLAN FOR EMERGENT WORK DURING OUTAGES?

A. Starting with our 2015 scheduled outage, the Company incorporated a contingency for anticipated emergent work, based on experience with historical outages. With this contingency, we are expected to remain on schedule and on budget for all outages, even when we encounter emergent work. When we encounter unplanned work, we evaluate the schedule and budget to determine how we can manage to the budget given current work requirements. However, the sites do not compromise on safety or reliability. If emergent equipment issues arise that could directly or indirectly pose a safety risk at the plant, the work will be performed and unplanned costs will be incurred.

Q. CAN YOU PROVIDE AN EXAMPLE OF EMERGENT WORK THAT ARISES DURING AN OUTAGE?

A. Yes. For example, the NRC requires compliance with the American Society for Mechanical Engineers (ASME) code[6] to inspect a certain population of plant components. If an indication is found during these initial inspections, the ASME code requires us to increase the population of components to be inspected. Similarly, we have periodic inspections for specific equipment components required by the NRC and mechanical engineering code at five- or ten-year intervals. Should issues be identified during these periodic inspections, we need to perform work to address the equipment concerns identified.

[6] The American Society of Mechanical Engineers (ASME) develops and issues codes and standards covering a breadth of topics, including pressure technology, nuclear plants, elevators / escalators, construction, engineering design, standardization, and performance testing.

Many ASME inspections involve what is called the military engineering sample approach. In this approach, a small sample of the population is inspected and if failures are found, the sample size is expanded. If further failures are found, the sample size is continually increased until eventually a 100 percent sample may be necessary. Examples of inspections using this approach are those involving snubbers, relief valves, flow accelerated corrosion, and welds.

When equipment failures are identified through inspections, we are bound by the NRC corrective action process, whereby all failures must have an extent of condition determination, with expanded inspection scopes occurring when conditions dictate.

For example, in the Prairie Island Unit 2 Fall 2019 outage, which was in process at the time this testimony was filed, we were required to test out the Main Steam Safety Valves per code. One of the valves did not pass this test, so a scope expansion was required by code. This required us to remove an additional 2 valves, send them to South Carolina for testing, then return them to the site to reinstall. They passed, and the reinstall is planned to be completed without impacting critical path. If one of these additional valves had failed, however, we would have needed to again expand scope to an additional five valves, which would have taken over critical path. This same scenario applies to other types of inspections that we are required to conduct during outages.

Q. HOW DOES THE COMPANY CATEGORIZE COSTS INCURRED DURING A PLANNED OUTAGE?

A. During a planned refueling/maintenance outage, there are three types of costs incurred:

- Outage work, with costs tracked separately via work orders and special codes;
- Capital projects, with costs tracked in separate capital work orders. These projects and their costs are subject to Capital Asset Accounting policies and oversight; and
- Non-outage, non-capital work, which is accounted for as a regular O&M expense.

The Company tracks outage costs consistent with the Commission's requirements for outage cost deferral/amortization. Exhibit___(TJO-1), Schedule 6, which is the Company's Planned Outage Policy, incorporates these requirements.

Costs incurred during an outage can only be included as incremental outage costs if they meet the Commission's deferral/amortization requirements, and can only be capitalized if they meet the Company's capitalization policies (which are based mainly on the requirements of FERC accounting regulations). The Commission has confirmed our method of deferral and amortization of outage costs in the Company's last several general rate cases. All costs not meeting the Commission's outage requirements or the Company's policies using FERC capitalization requirements are accounted for as non-outage O&M expense.

Q. HOW DOES THE COMPANY ADDRESS POTENTIAL CHANGES IN THE PLANNED OUTAGE O&M BUDGET AS THE PLANNING PROCESS PROCEEDS?

A. As I discussed earlier, the initial estimates of work schedule, scope and cost are updated during the outage planning process, right up until the start of the outage, and are impacted by emergent issues encountered during the outage. The planned outage O&M budget is revised periodically during the planning process based on changes needed in maintenance activity scope, the updates to the sequence of outage work activities, and the cost of various resources needed to perform the latest work activities.

After initial planning, potential scope and work changes are considered and the impact on outage duration, schedule, and cost evaluated. Regular challenge boards meet at the site and fleet level to identify opportunities to improve job performance, optimize the work schedule, and redeploy resources with the goal of doing the right level of work with minimal increase to planned outage cost.

We recognize that we need to balance the refueling and maintenance requirements of the plant with our ability to fund those activities given all Nuclear priorities and the limited O&M resources for the Company as a whole. The final outage budget considers both needs and available resources.

Q. PLEASE EXPLAIN HOW THE NUCLEAR OPERATIONS BUSINESS UNIT MONITORS OUTAGE O&M EXPENDITURES DURING THE OUTAGE TIMEFRAME.

A. Once the outage commences, the scope and schedule of outage refueling and maintenance activities are monitored by outage project management personnel to ensure the nature, timing, and sequence of activities are properly understood and appropriately planned. From a cost perspective, we use a daily outage tracking process to monitor the resources in place and planned to be on site, assess which are needed for each day's activities, which can be redeployed to other outage jobs if possible, and which can potentially be put on temporary standby or given days off until their work comes up in the outage queue. This tracking and monitoring enables us to avoid costs of unnecessary contract staff remaining on site when their work is rescheduled, and to avoid outage overtime and premium pay for internal labor when possible.

We oversee the work of contractors in the field, and continually review resource mobilization and demobilization curves for work planned. We use our Nuclear Oversight Services (NOS) group to oversee quality assurance for work performed. We have roving human performance teams to assure safety and compliance. This collective effort is designed to lead to efficiency, productivity, and optimal costs.

Q. HOW DOES THE COMPANY MANAGE INCREASES IN ACTUAL COSTS EXPERIENCED FROM THE PLANNED OUTAGE O&M BUDGETS?

A. Planned outage costs are part of the O&M budget that Nuclear is expected to manage to, as is every other Company business area. When we experience increases in planned outage costs from budget, we need to evaluate what opportunities we have to offset the higher outage costs in order to have overall O&M track with the budget expected for the year. The inclusion of contingency amounts within our outage budget have helped in this regard, as have our cost management efforts to lower the duration and cost of our planned outages.

Q. HOW DOES THE COMPANY'S MANAGEMENT OF ACTIVITIES FOR PLANNED OUTAGES COMPARE TO INDUSTRY PRACTICE?

A. Our scheduled outage planning process follows the industry process through use of standard milestones used to measure progress for planning. These milestones are discussed in our outage procedures and are measured in a "t minus" approach where we plan and oversee progress toward a critical milestone point. Under this approach, off-line maintenance work and capital projects during a planned outage have milestones for scope freeze and design modifications to be completed. Our procedure for outage preparations, Refueling Outage Management, is based on best industry practices shared through INPO as well as the EPRI.[7] Oversight of external contractors used during all projects is achieved through the guidance provided in our Contractor oversight procedure, which is based on industry guidance taken from INPO.

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[7] Electrical Power Research Institute's (EPRI) document 1022952, *Effective Refueling Outages* (www.epri.com).

Q. HOW DOES THE COMPANY'S MANAGEMENT OF COSTS FOR PLANNED OUTAGES COMPARE TO THE INDUSTRY?

A. Like us, all nuclear utilities have regular refueling outages during which they perform off-line maintenance work and construction projects. We regularly have an opportunity to benchmark other nuclear companies' experience with outage costs – formally and informally – through our industry groups, quality reviews, and interaction with peers. We have found two common areas of comparison that drive outage cost, the duration of an outage and the cost per outage day.

Duration – Some companies perform refueling outages every year, and with annual off-line maintenance opportunities and smaller reloads of fuel these companies can reduce outage duration to as low as 20 days. Companies with large fleets of plants with two-year fuel cycles, and centralized outage teams that travel from site-to-site in their fleets can complete outages without significant emergent issues in 30 to 35 days, with industry top quartile durations at 28 to 30 days. All companies experience longer outages when they have emergent issues to address.

Given construction projects with longer critical paths, required inspections and startup testing with likely emergent issues to address, and our small fleet of two sites, we are currently targeting 30 days as an efficient outage, with minimal emergent issues. As I discuss in my testimony later, we are building budgets based on outages of **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** for 2019 and 2020 at Prairie Island.

Cost per Day – In our recent outages without major capital projects (like EPU or steam generator replacement), we have experienced costs of slightly more than $1 million, or a little under $1 million, per planned outage day, with a higher cost per day for the initial portion of the schedule, and a slightly lower cost per day as outages went longer than planned. The reduction in cost per day for extended outages is due to the release of resources not needed to resolve the specific issues being addressed in extended periods beyond the original target schedule. Based on our benchmarking of other companies, we believe that $1 million per planned outage day is exceptional performance for short outages of 30 to 35 days.

The Company's outage amortization process includes pre-outage planning costs in total qualifying outage costs, which generally run $2 to $3 million each outage. In our benchmarking data above, pre-outage planning costs are not included in other companies' "cost per day" measure. Consequently, our total outage costs in comparing to other companies will be approximately $100,000 per outage day higher from including pre-outage planning costs.

As shown in Table 12, our forecast of costs for the fall 2019 outage is **[PROTECTED DATA BEGINS**… …**PROTECTED DATA ENDS]** per day, and the budget for the 2020 outage is **[PROTECTED DATA BEGINS**… …**PROTECTED DATA ENDS]** per day. The two most recently completed outages in 2018 and 19 had costs of $0.949 million and $1.1 million per day, respectively.

In the long term, our objective is to maintain a cost of about $1 million per planned outage day, which we have accomplished already, while working the duration downward through efficiency and effective labor/resource management. The changes we have made in our outage process, as well as the long-term contracts we've entered into with our key outage vendors are helping to drive both duration and overall cost down.

B. Planned Outage O&M Budget Components

Q. WHAT REFUELING OUTAGES IS THE NUCLEAR BUSINESS AREA INCLUDING FOR COST RECOVERY IN THE 2020 TEST YEAR?

A. The Commission has authorized the use of a deferral and amortization process to spread the costs of our scheduled refueling/maintenance outages over the period between outages. Under this approach, four planned refueling outages have costs that are amortized into the 2020 test year. They are the 2018 outage at Prairie Island Unit 1, the spring 2019 outage at Monticello, the fall 2019 outage at Prairie Island Unit 2, and the fall 2020 outage at Prairie Island Unit 1. Table 14 below summarizes the impact of amortization of these outages' costs in 2020.

Table 14

Planned Outage O&M Costs Included in 2020 Amortization Expense

($ in millions)

Unit / *Period*	PI Unit 1 Fall 2018	MT Spring 2019	PI Unit 2 Fall 2019	PI Unit 1 Fall 2020	Total 2020 O&M
Outage Duration (Days	35	30	30	30	
Total Outage O&M Cost	$ 33.2	$ 33.4	$ 32.0	$ 32.0	
Portion included in 2020 Amortization Expense	$ 12.5	$ 16.7	$ 16.7	$ 3.8	$ 49.7

The Company tracks these costs consistent with the Commission's requirements for outage cost deferral/amortization. Schedule 6 is the Company's policy incorporating these requirements and Company witness

Mr. Benjamin Halama explains the amortization of these planned outage costs in his Direct Testimony.

I will now discuss each of those outages affecting the 2020 test year further. Two of the outages were completed prior to summer 2019, and include actual costs through August 2019. The other two will take place in the fall of 2019 and 2020 and are based on estimated costs. Attached as Exhibit___(TJO-1), Schedule 7 (Public) is a detailed breakdown of the actual planned outage costs incurred for the 2018 and spring 2019 outages, and Exhibit___(TJO-1), Schedule 8 (Public) provides an estimate of the planned outage costs for fall 2019 and 2020.

1. Prairie Island Unit 1 – Fall 2018 Outage

Q. PLEASE DISCUSS THE OUTAGE'S DURATION AND TOTAL COST INCURRED.

A. The scope of the 2018 outage at Prairie Island Unit 1 included fuel reloading, a list of off-line maintenance projects and inspections, and several capital projects, including a large motor project, certain equipment upgrades, and replacement of the plant's original generator. In addition, we installed the new fuel design that I discussed previously. There was no significant emergent work identified during this outage. This outage lasted 35 days at a cost of $33.2 million, with the duration primarily driven by the generator replacement. For comparison purposes, the generator replacement at Prairie Island Unit 2, which was done during a 2015 outage, took 50 days, which demonstrates the effects of the improvements we have made in our outage processes.

2. Monticello – Spring 2019 Outage

Q. PLEASE DISCUSS THE OUTAGE'S DURATION AND TOTAL COST INCURRED.

A. The scope of the 2019 outage at Monticello included fuel reloading and a list of off-line maintenance projects and inspections. Specifically, several pieces of equipment were replaced or refurbished and two efficiency measures were implemented – Technical Specifications Task Force (TSTF) 425, which implements the Surveillance Frequency Control Program that I discussed earlier, which places periodic Surveillance Frequencies under licensee control, and TSTF 542, which moves from the concept of operations with a potential for draining the reactor vessel (OPDRVs) to the concept of Reactor Pressure Vessel Water Inventory Control (RPV WIC). These two measures provide additional flexibility in plant operations, with TSTF 425 reducing the work to be done during outages by reducing the frequency of required surveillances. Testing of the equipment identified a few emergent issues that resulted in replacement or repair of some equipment. These issues led to longer duration than planned, but did not lead to a budget overrun.

3. Prairie Island Unit 2 – Fall 2019 Outage

Q. PLEASE DISCUSS THE OUTAGE'S SCOPE, DURATION AND TOTAL ESTIMATED COST.

A. The scope of the fall 2019 outage at Prairie Island Unit 2 includes fuel reloading, a list of off-line maintenance projects and inspections, and certain capital projects. Specifically, we will upgrade the Ovation controls (governing feedwater), conduct NFPA 805 work, implement the Purification Modification I discussed in the Capital Investments section of my testimony, and repair or upgrade additional equipment. We will also implement the modified fuel design currently in place at Prairie Island 1, which will extend the time between refuelings from 18 to 24 months. In addition, we will implement TSTF 425 at this Unit. As of August 2019, the planned outage scope had a critical path schedule of **[PROTECTED DATA BEGINS**…

PROTECTED DATA ENDS]. The forecast for outage costs are $32.0 million, with approximately $2.4 million available for contingencies.

Q. PLEASE DESCRIBE THE SCOPE OF THE 2019 OUTAGE AT PRAIRIE ISLAND UNIT 2 IN COMPARISON TO PRIOR/OTHER OUTAGES.

A. This 2019 outage is forecast to be shorter and about the same cost as the last refueling for this unit in the fall of 2017, which lasted 38 days and had O&M outage costs of $32.1 million. Shorter outages do not necessarily drive reduced costs. For example, reducing the time to complete work can lead to increased labor costs in order to reduce work time. In addition, internal labor premium and overtime rates have increased along with other inflationary increases over the two years.

Q. HOW WERE THE ESTIMATED O&M COSTS FOR THE FALL 2019 OUTAGE DETERMINED?

A. As I noted earlier in my testimony, the workplan for each outage starts at the conclusion of the prior outage for the unit, and captures input from a number of sources (inspections required, equipment age and maintenance needs, risk and reliability analysis, etc.). Using this information, a plan is developed to scope out the work needed and the desired sequence of activities for efficient execution of an outage schedule. Resources needed are estimated in man hours, the use of internal versus external staffing is evaluated, and materials and equipment costs are projected.

Q. WHY IS THIS A REASONABLE ESTIMATE OF THE OUTAGE O&M FOR THIS OUTAGE?

A. The refueling outage budget process is dynamic, and planning remains fluid until the day the outage starts because it needs to adapt to emergent issues that may arise during the outage. The forecast for the fall 2019 outage was based on the best estimate of cost for scheduled activities and included a contingency for emergent issues anticipated as of August 2019. This estimate is consistent with our recent experience with comparable outages, as I noted earlier in my testimony.

4. Prairie Island Unit 1 – Fall 2020 Outage

Q. PLEASE DISCUSS THE 2020 OUTAGE'S EXPECTED DURATION AND TOTAL ESTIMATED COST.

A. The scope of the fall 2020 outage at Prairie Island Unit 1 includes fuel reloading and a list of off-line maintenance projects and inspections, and several capital projects that were safer to schedule while the unit was off-line. These projects include several projects discussed in the Capital Investments section of my testimony -- NFPA 805 work, work on the Process Controls Replacement Project related to the Prairie Island Feedwater Control System, implementation of the Purification Modification and control rod replacement. We will also implement TSTF 425 at Unit 1 during this outage. At this point in the planning process, we anticipate using approximately the same critical path schedule as our fall 2019 outage for Unit 2. The forecast for outage cost is $32 million.

Q. WHAT IS THE CURRENTLY ANTICIPATED SCHEDULE FOR THE 2020 OUTAGE?

A. Commencement of this outage is currently planned for **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**. Our generation production planning schedule assumed the unit would be off-line for **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**.

Q. HOW WERE THE ESTIMATED O&M COSTS FOR THE 2020 OUTAGE DETERMINED?

A. As I noted earlier in my testimony, the work plan for each outage starts at the conclusion of the prior outage for the unit, and captures input from a number of sources (inspections required, equipment age and maintenance needs, risk and reliability analysis, etc.). Using this information, a plan is developed to scope out the work needed and the desired sequence of activities for efficient execution of an outage schedule. Resources needed are estimated in man hours, the use of internal versus external staffing is evaluated, and materials and equipment costs are projected. As of late 2019, outage planning for the Unit 1 outage in 2020 was less developed and detailed than the Unit 2 outage that was commencing in fall 2019. More detailed work planning is to be completed for the 2020 outage at Unit 1 after conclusion of the Unit 2 outage in 2019.

Q. WHY IS THIS A REASONABLE ESTIMATE OF THE OUTAGE O&M FOR THIS OUTAGE?

A. The refueling outage budget process is dynamic and planning remains fluid until the day the outage starts, and needs to adapt to emergent issues that may arise during the outage. This estimate is consistent with our recent experience with comparable outages, as I noted earlier in my testimony, and actually assumes some cost savings in comparison to recent outages.

C. Multi-Year Rate Plan Outage O&M Costs

Q. WHAT IS THE LEVEL OF OUTAGE O&M EXPENSE NUCLEAR SEEKS TO RECOVER FOR THE 2021 AND 2022 PLAN YEARS?

A. Over our last several rate cases, the Commission has approved a method of deferring and amortizing Nuclear Outage O&M expenses between outages. Mr. Halama explains that process in his testimony. The amount of the Nuclear Outage O&M amortization is expected to decline during the course of this MYRP and the Company proposes to use its forecasted amortization amounts for purposes of establishing 2021 and 2022 Outage O&M expense. I support our budgeted annual Outage O&M expenses on an amortized basis, which are summarized below in Table 15.

Table 15

Nuclear Planned Outage O&M Forecasts – 2020-2022

Nuclear Operations Planned Outage O&M Amortization Expense ($ in millions)	**2020**	**2021**	**2022**	**Change 2021 vs. 2020**	**Change 2022 vs. 2021**
Outage O&M - Amortized	$ 49.7	$ 48.1	$ 47.5	-3%	-1%

Q. ARE THERE SPECIFIC DRIVERS THAT YOU HAVE IDENTIFIED FOR NUCLEAR THAT WILL IMPACT THE EXPENSE LEVELS FOR 2021 AND 2022 OUTAGE O&M BUDGETS?

A. Yes. As shown in our 2021 and 2022 supporting information, provided in Volume 6 of our Initial Filing, Nuclear is forecasting changes in its outage O&M expenses for Plan Years 2021 and 2022 in the following areas:

- Our 2021 amortized outage O&M budget is decreasing from 2020 levels due to the effects of the lower cost outage at Prairie Island in 2020 having a higher weighting in 2021 amortization versus 2020. This 2020 outage is occurring in the fall and thus has only a few months' amortization in 2020 versus a full year of amortization in 2021.
- Our 2022 amortized outage O&M is decreasing from 2021 levels due to anticipated lower average costs of planned outages in 2021 and 2022 in comparison to outages amortized into 2021 costs. We anticipate that we will be able to improve our outage planning and execution as I discussed previously, and accordingly have reflected cost decreases in our outage spend budgets for 2021 and 2022.

Q. OVERALL, IS THE COMPANY'S O&M COSTS FOR PLANNED OUTAGES, BOTH THOSE INCURRED AND THOSE FORECASTED FROM 2019-2022, REASONABLE?

A. Yes. Over the past few years, the Company has been able to predict and budget for some level of emergent work in its planned outages. Overall, outage duration and cost is trending down as a result of process changes we have adopted; the Company continues to implement measures that will increase outage efficiency and extend the time between outages.

VI. RESPONSE TO THE FINAL REPORT OF GEWC

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

A. In this section, I address the November 1, 2018 Final Report of Global Energy & Water Consulting LLC (GEWC) to the Department of Commerce regarding Prairie Island (the "Final GEWC Report"). I begin by providing a discussion of what led to the report and my reaction to one of the fundamental premises underlying the report. I then turn to GEWC's specific recommendations and discuss whether I believe each recommendation can reasonably be implemented.

Q. WHAT LED TO THE DEPARTMENT'S RETENTION OF GEWC AND ULTIMATELY TO THE FINAL GEWC REPORT?

A. The Department's retention of GEWC stemmed from both our 2015 Integrated Resource Plan (IRP) (Docket No. E002/RP-15-21) and our 2015 Multi-Year Rate Plan (MYRP) filing (Docket. No. E002/GR-15-826). In October of 2015, we filed Reply Comments in the IRP noting that we believed capital expenditures at Prairie Island would likely need to increase by roughly $600 to $900 million relative to our previous forecasts.

Around the same time, we filed our 2015 MYRP. As part of that case, we sought to recover costs associated with additional capital investments at Prairie Island, for which the Department ultimately recommended disallowance because the costs exceeded what we forecasted for capital expenditures at Prairie Island as part of our 2008 Certificate of Need for Additional Dry Cask Storage (Docket No. E002/CN-08-509).

In April of 2016, while both the IRP and MYRP were pending, the Commission determined that a "thorough analysis of all projected Prairie Island costs is critical to a fair and reasonable outcome in both the resource-plan and rate-case dockets."[8] The Commission therefore asked the Commissioner of Commerce to seek funding for specialized technical professional investigative services under Minn. Stat. § 216B.62, Subd. 8. Following that Order, the Department retained GEWC, which ultimately issued its Final Report on November 1, 2018.[9]

Q. WHAT IS YOUR GENERAL REACTION TO GEWC'S FINAL REPORT?

A. While GEWC's report makes some fair points regarding the challenges faced by the nuclear industry generally and the Xcel Energy nuclear team specifically, the report appears to be based on a mischaracterization of the Company's actual nuclear costs in relation to the forecast we provided as part of our 2008 Certificate of Need. A full and fair comparison of our actual performance to the modeling provided in connection with the 2008 Certificate of Need for Additional Dry Cask Storage demonstrates that we have achieved significant overall cost reductions relative to those forecasts.

Q. CAN YOU PROVIDE MORE CONTEXT REGARDING THE 2008 CERTIFICATE OF NEED AND WHAT THE MODELING FOR THAT CERTIFICATE WAS INTENDED TO DEMONSTRATE?

A. In 2008, we filed a combined application with the Commission for two Certificates of Need. The first certificate (Docket No. E002/CN-08-509) was for an extended power uprate project at Prairie Island that was

[8] E002/GR-15-826, April 15, 2016 Order.

[9] The 2015 MYRP ultimately resulted in a Stipulation of Settlement that resolved all issues in that case and was approved by the Commission on June 12, 2017.

ultimately cancelled following our 2012 Notice of Changed Circumstance. The second certificate (Docket No. E002/CN-08-510) was for additional dry cask storage to facilitate operation of Prairie Island for an additional 20 years beyond its then-licensed life. As part of that dry cask storage filing, we provided economic modeling that compared Prairie Island's cost effectiveness to both a super critical pulverized coal unit and a natural gas CC unit. That modeling incorporated a forecast of capital and O&M to run Prairie Island through 2034. We provided this information in response to Minn. Stat. §216B.243, subd. 3b, which states that "[a]ny certificate of need for additional storage of spent nuclear fuel for a facility seeking a license extension shall address the impacts of continued operations over the period for which approval is sought."

Q. IS THAT KIND OF MODELING TYPICAL OF CERTIFICATE OF NEED APPLICATIONS?

A. No. Typically, Certificates of Need are sought for specific construction projects. As part of those filings, utilities provide a forecasted capital budget that is based on some amount of engineering design and specific cost information for the project at issue. In our 2008 filing for additional storage, by contrast, there was no discrete construction project. Instead, we were seeking authority under Minn. Stat. § 216B.243 for additional spent fuel storage, and the statute required the Company to "address the impacts of continued operations" at Prairie Island. We complied with this requirement by providing a high-level cost estimate that included forecasted capital and O&M expense for the two-unit nuclear plant over a 26-year period and incorporated that data into modeling that demonstrated nearly $2.2 billion of expected benefits (on a present value of revenue requirements basis) compared to alternatives. See Exhibit___(TJO-1), Schedule 10, which is a CD containing Strategist modeling files from our 2008 Certificate of Need filing. This differs substantially from providing a capital budget for a specific construction project and getting approval from the Commission to build that project on the basis of that budget.

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THE COST REDUCTIONS YOU REFERENCED EARLIER?

A. Yes. In our 2008 Certificate of Need filing, we forecasted spending $3.64 billion at Prairie Island between 2008 and 2018 on a combined basis (capital plus O&M). To date, however, we have actually spent $3.24 billion to run the plant during this period, meaning we have reduced total capital and O&M relative to our 2008 forecast by approximately $400 million.

Looking forward to the end of Prairie Island's licenses, we forecasted in our 2008 Certificate of Need filing that we would spend $12.73 billion on a combined basis from 2008 through 2034. And today, we forecast spending several billion dollars less than our 2008 estimate, or $7.6 billion from 2008 through 2034 in combined capital and O&M.

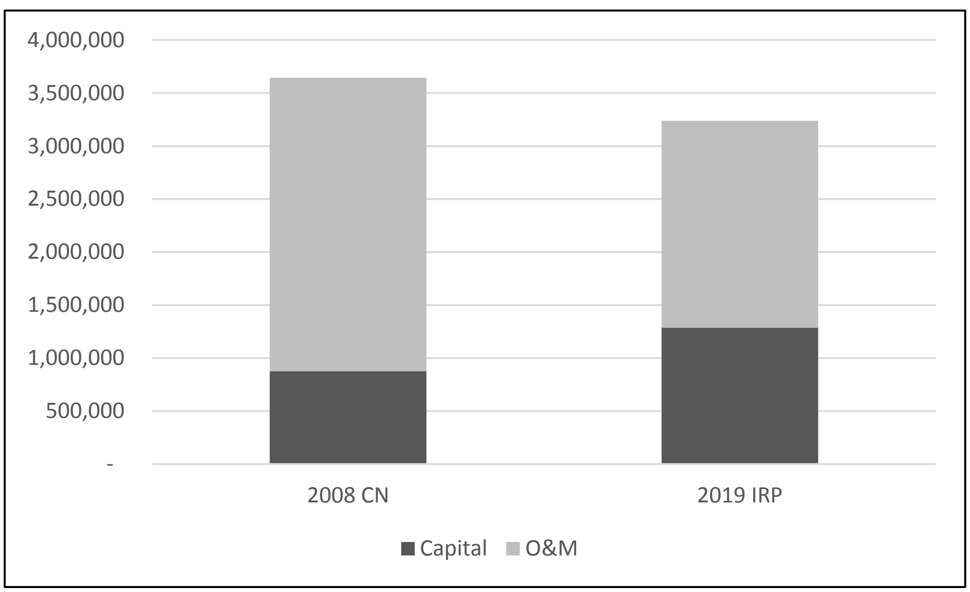
Q. IS GEWC CORRECT IN NOTING THAT XCEL ENERGY HAS EXCEEDED THE CAPITAL IT FORECASTED TO SPEND AT PRAIRIE ISLAND RELATIVE TO THE 2008 CERTIFICATE OF NEED?

A. Yes, we have invested more capital during this period than we anticipated in the 2008 Certificate of Need. At the same time, though, we have achieved more than $800 million dollars in O&M savings relative to our 2008 forecast, which more than offsets the higher capital spend (by the aforementioned $400 million). In other words, our modeling in support of our 2008 Certificate of Need substantially *understated* the benefits associated with the project due to the fact that we estimated higher overall costs than we have actually spent.

Q. CAN YOU PROVIDE A BREAKDOWN OF XCEL ENERGY'S CAPITAL AND O&M SPENDING AT PRAIRIE ISLAND FROM 2008-2018?

A. Yes, the following graph shows the differences between our 2008 forecast of capital and O&M compared and our actual spend through 2018:

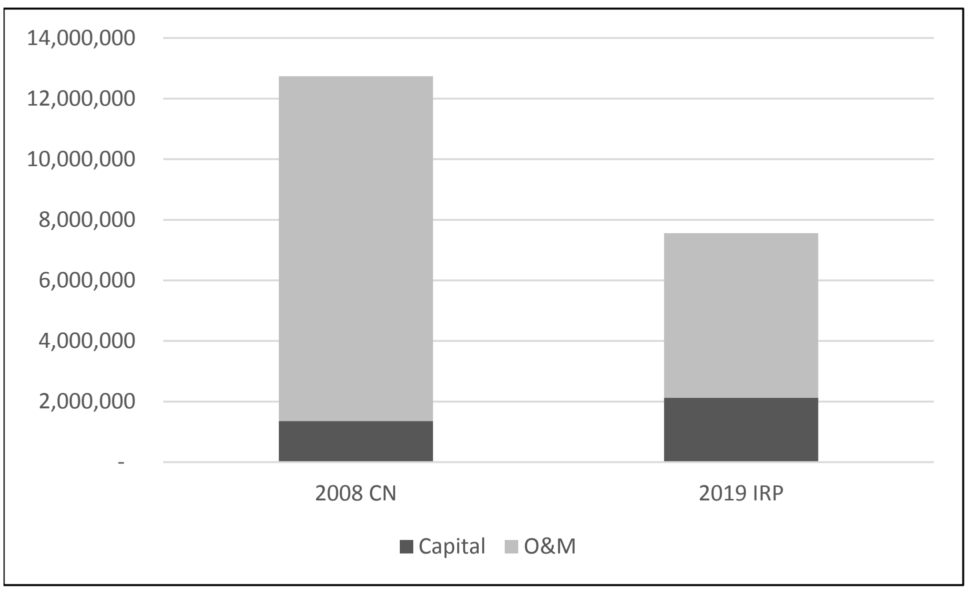
Figure 3
Sum of Costs 2008-2018
(Amounts in $000s)



Q. CAN YOU PROVIDE A BREAKDOWN OF XCEL ENERGY'S PROJECTED CAPITAL AND O&M SPENDING AT PRAIRIE ISLAND THROUGH THE END OF ITS LICENSED LIFE RELATIVE TO THE 2008 CERTIFICATE OF NEED?

A. Yes, the following graph shows the differences between our 2008 forecast and our actual spend plus 2019 IRP forecasted spend from 2008 through the end of Prairie Island's current license:

Figure 4
Sum of Costs 2008-2034
(Amounts in $000s)



Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DATA?

A. The data shows that we substantially understated the benefits associated with extending Prairie Island's license and acquiring additional dry fuel storage in our 2008 Certificate of Need filing. While graphs above show that we currently forecast increased capital expenditures relative to our prior estimates, those additional capital costs are vastly outweighed by significantly lower O&M spending. On a combined capital and O&M basis, we have spent—and project to spend—considerably less than we projected in our 2008 Certificate of Need. And this is the case despite the significant number of mandated compliance capital projects we had to complete after relicensing that we could not have reasonably predicted when we filed the 2008 Certificate of Need. GEWC's report ignores these offsetting O&M savings and, in doing so, unfairly mischaracterizes our overall spending relative to these earlier projections.

Q. DO YOU BELIEVE THERE IS ANY JUSTIFICATION FOR IMPOSING SEPARATE CAPS FOR CAPITAL AND O&M BASED ON THE COMPANY'S 2008 ESTIMATES?

A. No. To, in hindsight, impose an artificial "cap" on capital cost recovery of our investments (as has been previously suggested by the Department), without recognizing the tremendous O&M savings achieved, would penalize the Company for delivering a result that came in *well below* the total cost projection first set forth by the Company in 2008. It is also inconsistent with the purpose underlying our 2008 projections, which was to address the "impacts of continued operations"—not to provide a firm capital budget for a specific construction project. Neither the Certificate of Need statute nor the Commission's Order granting our Certificate of Need specified—or even suggested—the application of a cost cap, let alone a capital-specific cap that did not account for offsetting O&M savings.

Q. HAVE YOU NEVERTHELESS CONSIDERED THE FIVE RECOMMENDATIONS IDENTIFIED IN SECTION 7.0 OF GEWC'S FINAL REPORT?

A. Yes. I have reviewed the five recommendations in detail, and I have considered the feasibility, costs, and benefits associated with each of GEWC's recommendations.

Q. WHAT IS YOUR UNDERSTANDING OF GEWC'S FIRST RECOMMENDATION?

A. GEWC recommends that a mechanism be established requiring the Company to inform the Commission any time the Company discovers a mandated compliance issue. Upon discovery of such an issue, the Company should submit to the Commission a non-binding project description that includes project scope with specifics, compliance criteria, schedule and budget. The Company should then provide annual updates to the Commission as to project scope, compliance criteria, schedule, and budget, unless more frequent updates are warranted due to significant changes. GEWC also suggests that such reporting could be limited to projects that are budgeted for more than $5 million in any one calendar year, or $10 million in total cost. Finally, the burden of proof to demonstrate the recoverability of these costs would remain with the Company and would be adjudicated in a formal rate case.

Q. DOES GEWC SUGGEST ANYTHING FURTHER AS A PART OF THIS RECOMMENDATION?

A. Although GEWC notes that its first recommendation is made with specific reference to mandated compliance projects, GEWC also notes that it would be a good idea if this level of documentation were projected for any nuclear capital project.

Q. HOW DO YOU RESPOND TO GEWC'S FIRST RECOMMENDATION?

A. I find GEWC's recommendation to be reasonable and implementable as it relates to mandated compliance issues and projects that arise from those issues. GEWC is correct that regulatory mandates change over time and that these changes do not always sync with the Company's rate cases or other state regulatory proceedings in a way that facilitates real-time information sharing. GEWC is also correct that these compliance costs are not discretionary because they become a condition of maintaining our operating license.

As such, the Company can implement this recommendation with respect to mandated compliance issues going forward. Specifically, we will commit to making annual compliance filings with the Commission detailing any new or ongoing projects undertaken due to compliance issues. As part of those filings, we will provide initial information regarding project scope, compliance criteria, schedule, and budget. We will then update this information in future annual compliance filings, unless we encounter significant changes to project scope or cost, which we would bring to the Commission's attention on an expedited basis.

Q. WHEN DO YOU PROPOSE TO IMPLEMENT THIS REPORTING?

A. We would implement this reporting during the course of this MYRP following a Commission Order approving the process.

Q. IS THE COMPANY WILLING TO IMPLEMENT THIS REPORTING FOR BOTH PRAIRIE ISLAND AND MONTICELLO?

A. Yes. While GEWC's report relates solely to Prairie Island, I believe this recommendation could be beneficial in relation to both Prairie Island and Monticello.

Q. HOW DO YOU RESPOND TO GEWC'S SUGGESTION THAT THIS REPORTING COULD OCCUR FOR ALL NUCLEAR PROJECTS?

A. I do not believe this recommendation could feasibly be implemented with respect to all nuclear capital projects. In any given year, the Company completes between 40 and 140 nuclear capital projects ranging from the tens of thousands to hundreds of millions of dollars in total expenditures. The Company's rate cases provide adequate documentation for capital projects outside the mandated compliance category. Because the mandated compliance category presents a unique set of circumstances due to emergent and changing regulatory mandates, I believe that the benefit of implementing GEWC's recommendation with respect to mandated compliance capital projects would not extend to projects outside of the mandated compliance category.

Q. WHAT IS YOUR UNDERSTANDING OF GEWC'S SECOND RECOMMENDATION?

A. GEWC recommends a number of modifications to the way the Company presents budgets in connection with Certificates of Need. First, GEWC recommends that the Company's policies and procedures be modified to require it to present initial budget estimates in Certificates of Need only after a minimum of 60 percent engineering design has been completed. Second, GEWC recommends that capital budget estimates have a minimum 50 percent contingency in the budget and that the 50 percent contingency be included in all financial pro formas and planning models. Third, GEWC recommends that the Company be required to file a revised budget if—during the execution of a project—there is a 15 percent change in the budget estimate or a schedule delay that may cause upward pressure on the budget and that any such revised budget should include a full and concise explanation of the causal actions and the resultant impacts.

Q. HOW DO YOU RESPOND TO THE FIRST PART OF THIS RECOMMENDATION—THAT THE COMPANY ONLY BRING FORWARD CERTIFICATES OF NEED AFTER A MINIMUM OF 60 PERCENT ENGINEERING DESIGN HAS BEEN COMPLETED?

A. While I understand GEWC's concern regarding preliminary budgets underlying Certificates of Need, I do not believe the 60 percent engineering design threshold proposed by GEWC is reasonably practicable given the current regulatory framework in Minnesota. Frequently, the detailed engineering required to achieve the proposed 60 percent threshold could comprise a substantial component of the overall project. For example, the engineering component of the Prairie Island Extended Power Uprate (EPU) project (that was ultimately canceled) amounted to more than $12 million in vendor costs. It would not be appropriate for the Company to make these investments for a project that is ultimately subject to the Commission's Certificate of Need requirements without first evaluating the need for the project and bringing the evaluation—including initial cost estimates and economic modeling for the project— before the Commission. That said, much of GEWC's second recommendation—in combination with increased transparency regarding the state of our detailed engineering design work in the context of future Certificates of Need—should largely address GEWC's concerns regarding the uncertainty around large-scale capital projects at our nuclear plants.

Q. HOW DO YOU RESPOND TO THE SECOND PART OF THIS RECOMMENDATION—THAT THE COMPANY INCLUDE A MINIMUM OF 50 PERCENT CONTINGENCY IN CAPITAL BUDGETS FOR CERTIFICATES OF NEED AND THAT THIS 50 PERCENT CONTINGENCY BE INCLUDED IN ALL FINANCIAL PRO FORMAS AND PLANNING MODELS?

A. The appropriate amount of contingency for a particular capital project should vary depending on the specifics of that project, including its complexity, our experience in completing similar projects, our use of outside vendors with expertise in such projects, and the nature of our contract terms with outside vendors for the work in question. Our capital budgets routinely include contingencies that range from 15 percent to 50 percent of the total project budget, depending on the state of our detailed engineering work, and the factors I identified above. This practice is consistent with industry best practices. The consistent use of a 50 percent or more contingency in our capital budgets would tend to overstate a reasonable estimate of the actual costs to complete the project in question, which could bias decision-making against projects that are very likely to be economic and in the public interest. That said, a hybrid approach in line with GEWC's recommendation may be reasonable. Specifically, the continued use of reasonable, project-specific contingencies is appropriate and, together with increased transparency around the use of those contingencies, can assist the Department, Commission, and stakeholders in meaningfully evaluating our budgets and Certificates of Need. Additionally, we are open to the use of capital budget sensitivities, including a 50 percent sensitivity – in our modeling for Certificates of Need can also help accomplish this end.

Q. PLEASE EXPLAIN THE COMPANY'S USE OF CAPITAL BUDGET SENSITIVES IN ITS MODELING AND COMPARE THAT TO GEWC'S RECOMMENDATION THAT THE COMPANY INCLUDE A 50 PERCENT CONTINGENCY IN THE ACTUAL PROJECT BUDGET.

A. For Certificates of Need, the Company provides an estimate of costs to complete the project in question. That estimate includes a certain amount of contingency to reflect the need to complete detailed engineering and the inherent uncertainties of forecasting costs for large-scale nuclear capital projects. The Company's use of such contingencies is consistent with industry standards and best practices, but those contingencies typically do not approach 50 percent of the total project cost, as recommended by GEWC. However, the Company's economic modeling in support of Certificates of Need also typically includes sensitivities that evaluate a spectrum of scenarios and modeling assumptions. Those sensitivities include, among other things, increased capital costs. In effect, these "high capital cost" sensitivities evaluate the economics of capital project with an even greater amount of budget contingency, so the Commission and other parties can evaluate the prudence of a project given the risk of increased capital costs.

Q. IS THE COMPANY WILLING TO INCLUDE MODELING SENSITIVITIES IN FUTURE CERTIFICATES OF NEED THAT—IN COMBINATION WITH ACTUAL BUDGET CONTINGENCIES—EVALUATE THE IMPACT OF A COMBINED 50 PERCENT INCREASE TO TOTAL PROJECT COSTS?

A. Yes. We can commit to identifying the amount of contingency used in future capital budgets underlying Certificates of Need and also to including economic modeling sensitivities that effectively increase those contingencies to a minimum of 50 percent of total project cost. I believe this approach achieves the goals underlying GEWC's second recommendation while preserving the Company's interest in maintaining capital budgets that realistically reflect our best analysis and assumptions of what a project will ultimately cost to complete and put in-service.

Q. HOW DO YOU RESPOND TO THE THIRD PART OF THIS RECOMMENDATION—THAT THE COMPANY BE REQUIRED TO FILE A REVISED BUDGET IF THERE IS A 15 PERCENT CHANGE IN THE BUDGET ESTIMATE OR A SCHEDULE DELAY THAT MAY CAUSE UPWARD PRESSURE ON THE BUDGET?

A. The Company will commit to filing these updates in future Certificate of Need dockets. As part of such filings, we would include a full explanation regarding the drivers or causes of any such changes and how the changes might impact both the economic modeling and the public interest analysis underlying the Certificate of Need.

Q. DO YOU BELIEVE THESE COMMITMENTS WILL IMPROVE THE COMMUNICATIONS, DOCUMENTATION, AND TRANSPARENCY AROUND PROJECT ESTIMATES AND FUTURE CERTIFICATES OF NEED?

A. I do. While it is not reasonably practicable to complete a minimum of 60 percent engineering design prior to filing some Certificates of Need, I believe the remaining portions of GEWC's recommendations—with the slight modifications I propose above—will give the Commission, Department, and other stakeholders, increased visibility into the accuracy of our capital budgets, the amount of contingency we believe is appropriate for a specific capital project, and the impact of capital costs over and above our contingency, up to a minimum of 50 percent of the total project cost. Additionally, the commitment to file revised budgets and analysis in the event of certain changes during the course of a capital project will give the Commission and parties the opportunity to weigh in on the overall project in light of such changes in real time, rather than after the fact in the context of a future rate case.

Q. WHAT IS YOUR UNDERSTANDING OF GEWC'S THIRD RECOMMENDATION?

A. GEWC recommends that if the Company provides any benchmarking study in the future to justify its performance, the Commission should at least require the Company to produce complete copies of such studies and supporting documentation before giving any weight to the information. GEWC also recommends that no benchmarked results should be accepted as accurate or representative without collaboration by the Commission and the Department.

Q. HOW DO YOU RESPOND TO THIS RECOMMENDATION REGARDING THE USE OF BENCHMARKING STUDIES?

A. I do not object to this recommendation. It is common practice in the nuclear industry to benchmark a plant's or team's performance against the industry or a particularly high-performing plant in order to assess performance and incorporate best practices. In fact, Xcel Energy's nuclear fleet has frequently been used as a benchmark for other plants across the industry in recent years due to our strong performance. We nevertheless continue to benchmark our plants and nuclear teams against other operators in order to study best practices and improve our own performance. Oftentimes, those benchmarking studies are conducted pursuant to non-disclosure agreements, so operators can share nonpublic information knowing that the information will be protected from public disclosure. That said, to the extent the Company relies upon any benchmarking study in the future, we can commit to providing the complete analysis and datasets underlying the study, consistent with any confidentiality or non-disclosure obligations that may apply. To the extent we cannot provide the complete analysis due to our confidentiality or non-disclosure obligations, we recognize that the Commission may consider that in evaluating the relative weight to attach to those benchmarking results.

Q. WHAT IS YOUR UNDERSTANDING OF GEWC'S FOURTH RECOMMENDATION?

A. GEWC recommends that the Company address a number of questions in its 2019 Integrated Resource Plan. These questions include: (1) whether a second life extension for some or all of the nuclear generation facilities is the best alternative for the Xcel Energy generation fleet; (2) what alternatives would there be to Prairie Island 1, 2, or both; (3) would the NRC approve another life extension and what analysis and filing requirements would be necessary; (4) what would Xcel Energy need to do to obtain a second license extension; and (5) what issues would need to be addressed locally if there is any additional life extensions requested.

Q. HOW DID XCEL ENERGY RESPOND TO THIS RECOMMENDATION IN ITS 2019 INTEGRATED RESOURCE PLAN?

A. Our 2020-2034 Integrated Resource Plan filing presented a Preferred Plan that includes a license extension at Monticello and the continued operation of Prairie Island through its current operating licenses. We explained in that filing that we are deferring a decision on pursuing license extensions at Prairie Island until subsequent resource plans due to the additional time before the Prairie Island licenses expire and our desire to preserve flexibility to respond to future market conditions. As part of our economic analysis in the resource plan, however, we modeled scenarios that included early retirements, license extensions, and continued operations through current licenses for all three of our nuclear units and compared those outcomes to a variety of other modeling scenarios. While the NRC grants license extensions in 20-year increments, we also explained that we viewed it as prudent to limit our analysis to 10 additional years at this juncture, given the uncertainty of projecting more than 30 years into the future from both a budgeting and resource-planning perspective. Finally, we discussed the NRC relicensing process and assessment criteria, along with our proposal to submit a Certificate of Need with the Commission for additional dry cask storage at Monticello.

In short, the Company is taking a proactive approach to planning for the expiration of our current NRC licenses, and we believe the path laid out in the resource plan is reasonable and provides for a measured and transparent approach to considering the future of our nuclear fleet.

Q. WHAT IS YOUR UNDERSTANDING OF GEWC'S FIFTH RECOMMENDATION?

A. At a high level, GEWC recommends that Xcel Energy maintain a more proactive communications path with the Commission and the Department. GEWC then makes two more specific recommendations. First, GEWC recommends that Xcel Energy identify the components of its estimated $187 million in costs that were avoided due to not proceeding with the EPU in 2012. Second, GEWC recommends that Xcel Energy provide further information to demonstrate that the Company would not have undertaken mandated compliance projects identified in Tables 7 and 9 of GEWC's report but for the NRC requirements stemming from the Fukushima accident. GEWC also recommends that Xcel Energy provide the NRC requirements to support that assertion.

Q. WHAT IS YOUR RESPONSE TO GEWC'S FIFTH RECOMMENDATION?

A. To start, I want to note that I believe the Company has been transparent with the Commission with respect to our nuclear operations over time. Over the course of several rate cases filed with the Commission since 2010, we have detailed our progress in working toward a standard of excellence that today places us at the top of the industry. In our 2013 case (Docket No. E002/GR-13-868), I explained in Direct Testimony that the nuclear industry had improved faster than Xcel Energy's nuclear team and that we had initiated a performance excellence plan to address those shortcomings. I explained that this plan would address equipment issues as well as human performance, leadership effectiveness, and safety culture, and that its overall aim was to bring our plants into the top quartile of industry performance. Today, I am proud to say that we have achieved that goal and more.

Q. DID YOU DISCUSS THE PERFORMANCE EXCELLENCE PLAN IN THE COMPANY'S 2015 CASE AS WELL?

A. I did. In my Direct Testimony in Docket No. E002/GR-15-826, I provided an update on the performance excellence plan and noted that we had added employees that were helping the plants achieve their goals and also helping to reduce our reliance on—and the cost of—external vendors. I also explained that, in 2013, we had some specific needs for contractors to support our efforts in addressing NRC findings related to, among other things, human performance issues at both sites, but that we were successful in reducing reliance on these contractors in 2014. I also noted my disappointment that we did not achieve a third of our scorecard/KPI goals in 2014 because we were below target for equipment performance, regulatory margin, and leadership effectiveness. On the other hand, I explained we were seeing improvement in INPO's measures for tracking operational performance and that our performance excellence plan was proving to be successful.

Q. IN YOUR OPINION, WAS THE PERFORMANCE EXCELLENCE PLAN ULTIMATELY A SUCCESS?

A. Absolutely. As a result of our performance excellence plan, we surpassed our goal of achieving top-quartile performance, and our plants have never operated better. In fact, we are the only nuclear fleet in the industry that has all units in Exemplary Status at INPO, all units in NRC Column 1 Status with all green performance indicators, and all units with no NRC Safety Culture Concerns. At the same time, and as I have already discussed, our production costs per MWh are at their lowest point in over a decade. These performance and cost improvements are the direct result of investments we made in our plants over the past seven years and also the focus we brought to improving human performance and leadership at our plants—all of which was part of our performance excellence plan.

Q. DO YOU, NEVERTHELESS, AGREE WITH GEWC THAT ADDITIONAL PROACTIVE COMMUNICATION WOULD BE BENEFICIAL?

A. I agree that the Company and our regulators can benefit from additional proactive communication, and I believe a number of the commitments already discussed in this section will facilitate greater transparency and information sharing. We welcome the opportunity to increase communication between the Company and our regulators about the operation and performance of our nuclear fleet. I will note that the Company was fully cooperative in responding to GEWC's information requests and accommodating their site visits and employee interviews. And we would welcome additional future site visits by the Department and/or GEWC, as well as regular meetings to engage in information sharing and dialogue regarding our nuclear operations. I believe this kind of informal information exchange would be an efficient and valuable way to keep the Department informed in near-real time regarding our nuclear operations.

Q. WHAT IS YOUR RESPONSE TO GEWC'S SPECIFIC RECOMMENDATION THAT XCEL ENERGY IDENTIFY THE COMPONENTS OF ITS ESTIMATED $187 MILLION IN COSTS THAT WERE AVOIDED DUE TO NOT PROCEEDING WITH THE EPU IN 2012?

A. The Prairie Island EPU would have required modifications to plant equipment to support higher power levels under EPU operations, including changes to feedwater valves, feedwater pumps and motors, pump and motor cooling components, and other instrumentation. Those unique EPU modifications were still in the study phase when the EPU was terminated. After the Commission approved the EPU termination in December 2012, those unique EPU modifications were no longer necessary and further study and implementation of the modifications was abandoned. These unique modifications are the components of the EPU that were avoided due to the cancellation, and we estimated at the time of our Notice of Changed Circumstance filing in March of 2012 that these modifications would amount to $187 million in total costs. As discussed in Mr. Scott Weatherby's Direct Testimony in Docket No. E002/GR-13-868, the EPU program was not far enough along at the time of its cancellation to have separate work orders collecting costs for EPU-affected equipment modifications that were being studied but ultimately not implemented due to termination.

Q. DID CANCELLATION OF THE EPU MEAN THE COMPANY DID NOT NEED TO UNDERTAKE ANY MODIFICATIONS OR REPLACEMENTS WITH RESPECT TO THE PIECE OF EQUIPMENT YOU IDENTIFIED ABOVE?

A. No. We are constantly monitoring and maintaining plant operating equipment as part of Life Cycle Management (LCM) program. This LCM included modifications, refurbishment and/or replacement of components that would have been replaced as part of the EPU. However, our LCM work did not involve any of the "upsizing" or unique modifications to this equipment that would have been necessary to implement the EPU and operate Prairie Island at the higher capacity levels contemplated by the EPU project.

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO SAY IN RESPONSE TO GEWC'S CONCLUSIONS AND RECOMMENDATION REGARDING THE 2012 EPU AT PRAIRIE ISLAND.

A. Yes, two things. First, I want to note that we responded to several information requests from GEWC related to the cancelled EPU project at Prairie Island during the course of GEWC's assessment. As part of those responses, we provided all available information regarding the cancelled EPU project and the costs and modifications that were avoided due to the cancellation, as discussed in my prior answer. Second, I want to point out that the EPU cancellation was a central issue in our 2013 rate case and, in that case, Mr. Scott Weatherby provided a detailed breakdown between costs assigned to the EPU versus costs that would proceed under our life cycle management program. As a result of that case, the Commission approved recovery of the EPU-related costs in the form of amortization of a regulatory asset (without a return). In approving this recovery, the Commission concluded:

> The Commission concurs with the ALJ that the record demonstrates that Xcel acted prudently and in good faith both in developing the project and in cancelling it. The Company did not embark on the project hastily or unilaterally—the need for and

reasonableness of the project were scrutinized by stakeholders and regulators during an exhaustive Certificate of Need proceeding, which resulted in the Commission issuing a Certificate of Need.

Nor did the Company fail to recognize, react to, and disclose signs of trouble as they developed. Less than two months after the NRC meeting clarifying the new licensure standards and process, the Company filed a notice of its intent to update its resource plan in light of these and other realities. Less than two months later, it filed the update, which laid out the challenges the project faced and attempted to compare its costs and benefits with those of alternative resources.

Q. WHAT IS YOUR RESPONSE TO GEWC'S FINAL SPECIFIC RECOMMENDATION THAT XCEL ENERGY PROVIDE FURTHER INFORMATION TO DEMONSTRATE THAT THE COMPANY WOULD NOT HAVE UNDERTAKEN MANDATED COMPLIANCE PROJECTS IDENTIFIED IN TABLES 7 AND 8 OF GEWC'S REPORT BUT FOR THE NRC REQUIREMENTS STEMMING FROM THE FUKUSHIMA ACCIDENT?

A. Exhibit___(TJO-1), Schedule 11 lists the projects identified in Tables 7 and 8 of GEWC's Report and lists the NRC mandate underlying each project. Some of these projects were a direct result of Fukushima but some resulted from other NRC mandates that were adopted after 2008 in response to changing regulatory standards and industry events. Nonetheless, in each case, these projects would not have been necessary or completed absent the specific mandates identified in Schedule 11.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve the Nuclear capital investments and O&M budget presented in this rate case. Xcel Energy's Nuclear fleet provides more than 1700 megawatts of safe, reliable, carbon-free generation that serves more than one million customer homes and is critical to the Company's and the State's goals of supporting a clean energy future. Our capital investments focus on plant reliability and improvements, and the fuel, storage, and compliance requirements necessary to continue to operate these plants into the future. Our O&M expense budgets reflect the operating costs needed to effectively run, maintain, and refuel our fleet of nuclear plants. We have managed our O&M activities to keep the rate of future cost growth low and to operate our plants as efficiently as possible.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Timothy J. O'Connor
Chief Nuclear Officer

Tim O'Connor is Chief Nuclear Officer for Xcel Energy. He is responsible for all Xcel Energy nuclear activities in Minnesota at the Monticello and Prairie Island nuclear generating plants as well as Xcel Nuclear Corporate Oversight and Governance (operated by NSP-Minnesota and its parent company, Xcel Energy).

Mr. O'Connor joined Xcel Energy in 2007 as the site vice president of the Monticello plant. He has 36 years of commercial nuclear experience with both boiling and pressurized water reactors. His increasing responsibilities throughout his career have included site vice president at Constellation Energy Group's Nine Mile Point station in New York; vice presidential roles at the Public Service Enterprise Group (PSEG) Hope Creek and Salem plants; plant manager at LaSalle station; and operations manager at Dresden and Zion plants. He has also worked in management positions in maintenance, operations, and engineering. Mr. O'Connor also held a position with the Institute of Nuclear Power Operations (INPO) as an evaluation team manager on a reverse loaned assignment.

Mr. O'Connor received his mechanical engineering degree from Marquette University in Milwaukee.

FACT SHEET

MINNESOTA AND NUCLEAR ENERGY

Key Facts

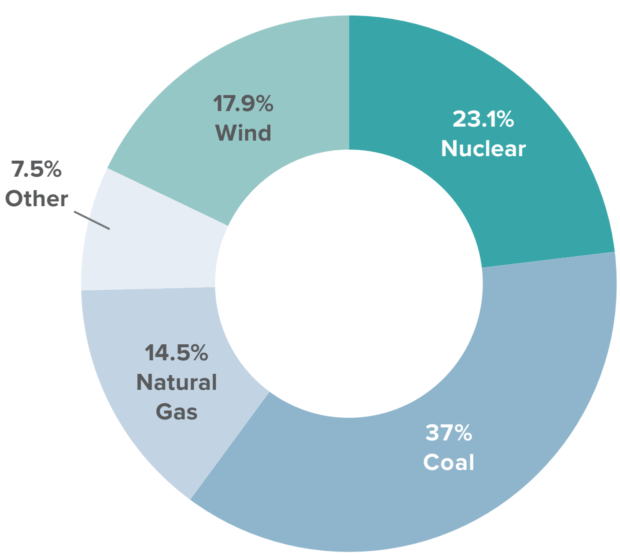
- Minnesota's three nuclear power reactors generate **23 percent** of the state's electricity while emitting no greenhouse gases
- Nuclear energy is Minnesota's **most reliable power source**, producing electricity around-the-clock
- Minnesota's nuclear energy facilities employ more than **1,500 workers**

Infrastructure for Clean, Reliable Electricity

Minnesota is home to three nuclear power reactors that produce 51 percent of the state's emission-free electricity. These nuclear energy facilities protect air quality and public health. Nuclear energy generates nearly 20 percent of our nation's electricity and provides more than 55 percent of our emission-free power, making it an essential partner to renewable energy.

Nuclear is America's most reliable source of electricity. Minnesota nuclear plants produced power more than 97 percent of the time over the past three years, ensuring power is available whenever it is needed. Nuclear energy is a vital part of U.S. infrastructure that keeps electricity prices and grids stable. It ensures that consumers are not overly reliant on just one or two sources of electricity.

Sources of Electricity in Minnesota



Source: ABB Velocity Suite / U.S. Energy Information Administration

Other includes petroleum, biomass and geothermal along with hydro, wind and solar if they account for less than 3% of electricity generated.

Nuclear Energy Facilities

Facility	Company	Location	Capacity (MW)	Capacity Factor (%)[1]
1 Monticello	Xcel Energy	Monticello	617	101.5
2 Prairie Island 1	Xcel Energy	Red Wing	521	94.6
3 Prairie Island 2	Xcel Energy	Red Wing	519	95.4
		State Totals	**1,657**	**97.6**

Source: U.S. Energy Information Administration

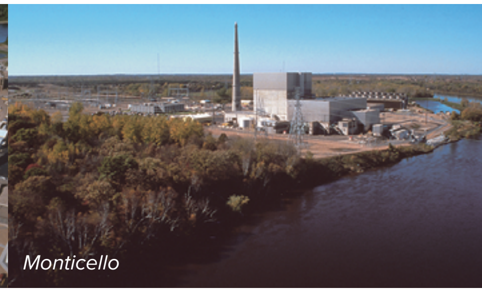
[1] Capacity factor three-year average is electricity produced compared to the maximum that could be produced and is calculated based on generation in 2016, 2017 and 2018.

Supporting Jobs and the Economy

- Nuclear energy facilities in Minnesota employ more than 1,500 workers.
- American innovators are developing new nuclear technologies that have the potential to create additional jobs and bring in export dollars.

continued —

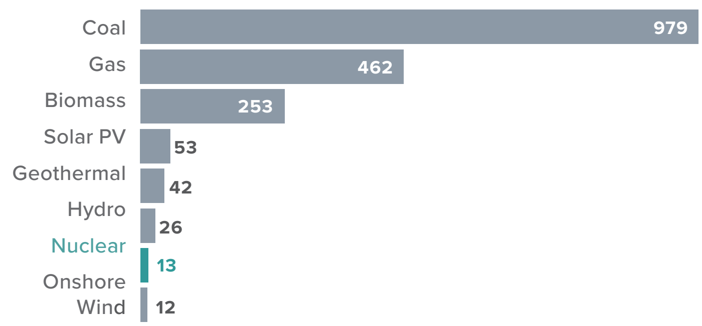

Monticello


Monticello


Prairie Island

Comparison of Life Cycle Emissions

Tons of Carbon Dioxide Equivalent per Gigawatt-Hour



Source: Annex III: Technology-specific cost and performance parameters. In: Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, Edenhofer, O., et.al, Cambridge University Press, 2014. The numbers shown are the median of studies examined by the IPCC in grams CO2e per kWh and are converted to tons CO2e per GWh.

Nuclear Is Clean Air Energy

- The use of nuclear energy in 2018 prevented the emission of 528 million metric tons of carbon dioxide. This equals the amount released in a year by 112 million passenger cars.
- Nuclear energy is the only clean air electricity source that can produce large amounts of electricity around-the-clock.
- Numerous studies demonstrate that nuclear energy's life cycle greenhouse gas emissions are comparable to renewable energy, such as wind and hydropower, and far less than coal or natural gas-fueled power plants.
- The nation's nuclear energy facilities also prevented the emission of 346,485 short tons of sulfur dioxide and 286,516 short tons of nitrogen oxide in 2018.

Emissions Prevented in Minnesota	Quantity Prevented in 2018
Sulfur dioxide (SO2)	15,302 short tons
Nitrogen oxide (NOX)	10,722 short tons
Carbon dioxide (CO2)	13.64 million metric tons

Source: U.S. Environmental Protection Agency and U.S. Energy Information Association

Committed to Safety

- America's nuclear energy facilities are among the safest and most secure industrial facilities.
- The independent U.S. Nuclear Regulatory Commission regulates and monitors plant performance in three areas: reactor safety, radiation safety and security.
- After more than 60 years of commercial nuclear energy production in the United States and more than 4,000 reactor years of operation, there have been no radiation-related health effects linked to the operation of nuclear energy facilities.

Managing Used Nuclear Fuel

- Each nuclear energy facility stores used fuel safely and securely on-site, awaiting consolidated storage and disposal by the U.S. Department of Energy. As of 2016, Minnesota has contributed approximately $456 million to the federal Nuclear Waste Fund.
- There are 1,436 metric tons of used nuclear fuel in storage at nuclear plant sites in Minnesota.
- All the used nuclear fuel produced by the nuclear energy industry over 60 years—if stacked end to end—would cover an area the size of a football field to a depth of less than 10 yards.

Used fuel at nuclear energy facilities is cooled in secure steel-lined concrete pools filled with water.

After the cooling period, nuclear energy facilities store used fuel safely on-site in steel and concrete vaults.

Source: Gutherman Technical Services

NUCLEAR ENERGY INSTITUTE

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NEI

Emissions Avoided by U.S. Nuclear Industry by State

Greenhouse gas emissions avoided by U.S. Nuclear power plants in 2018

STATE	SULFUR DIOXIDE (SHORT TONS)	NITROGEN OXIDES (SHORT TONS)	CARBON DIOXIDE (MILLION METRIC TONS)
Alabama	14,308	14,764	27.54
Arizona	5,647	14,155	20.89
Arkansas	9,505	6,240	7.87
California	41	720	7.33
Connecticut	1,145	1,720	7.57
Florida	4,442	5,333	14.86
Georgia	4,728	10,439	21.60
Illinois	62,081	38,329	69.85
Iowa	5,130	3,595	4.57
Kansas	6,397	4,492	7.02
Louisiana	12,816	8,414	10.61
Maryland	8,491	5,668	10.31
Massachusetts	301	453	1.99

The Impact of Xcel Energy's Nuclear Fleet on the Minnesota Economy

An Analysis by the Nuclear Energy Institute

April 2017

NUCLEAR ENERGY INSTITUTE

www.nei.org

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Executive Summary

Xcel Energy Inc. (Xcel Energy) owns and operates two nuclear energy facilities, including three reactors, in Minnesota and has its headquarters in Minneapolis, Minnesota. The two nuclear energy facilities are:

- Monticello Nuclear Generating Plant in Monticello, Minnesota
- Prairie Island Nuclear Generating Plant in Red Wing, Minnesota

Almost 6,100 jobs in Minnesota result from Xcel Energy's nuclear operations.

The two nuclear facilities have been an integral part of the region's clean energy portfolio and economic fabric since the 1970s. They have generated reliable emission-free electricity, thousands of jobs, and billions of dollars of economic activity while Xcel Energy has been deeply involved in its local communities, proving the plants' value as economic contributors to Minnesota and the Upper Midwest.

To quantify the employment and economic impact of these facilities, the Nuclear Energy Institute (NEI) conducted an independent analysis. Based on data provided by Xcel Energy on employment, operating expenditures, revenues and tax payments, NEI conducted the analysis using a nationally recognized model to estimate the facilities' economic impacts on the Minnesota economy. Regional Economic Models, Inc. (REMI) developed the Policy Insight Plus (PI+) economic impact modeling system, the methodology employed in this analysis. (See section 5 of this report for more information on the REMI methodology.)

Key Findings

Xcel Energy's nuclear operations support:

Xcel Energy's nuclear operations are estimated to generate $1 billion of total economic output annually in Minnesota.

Economic stimulus. Xcel Energy's nuclear operations are estimated to generate $1 billion of total economic output annually, which contributes $600 million to Minnesota's gross state product each year. This study finds that for every dollar of output from Xcel Energy's nuclear operations, the state economy produces $1.98.

Tax impacts. NEI estimates that Xcel Energy's nuclear facilities in Minnesota contribute about $33 million in state and local taxes annually. In 2015, Xcel Energy reported over $34.5 million in state and local taxes paid. Xcel Energy is the largest property tax payer in Minnesota. NEI estimates that Xcel Energy's nuclear facilities contribute over $113 million in federal taxes each year.

Thousands of high-skilled jobs. Approximately 1,700 jobs exist at Xcel Energy's nuclear energy facilities, which includes 140 nuclear support positions at its headquarters in Minneapolis. This direct employment creates about 4,200 additional jobs in other industries in Minnesota. A total of nearly 6,100 jobs in Minnesota are a result of Xcel Energy's nuclear operations.

Xcel Energy's nuclear operations result in a total tax impact of approximately $146 million to the local, state and federal governments each year.

Clean electricity for Minnesota. Xcel Energy's nuclear facilities generate about 21 percent of Minnesota's electricity and about 54 percent of the state's carbon-free electricity. Without the carbon-free electricity produced by these nuclear plants, an estimated 12 million metric tons of carbon dioxide would be released annually, the equivalent of putting more than 2.6 million additional cars on Minnesota's roadways each year, or double the number of passenger cars in all of Minnesota. By 2030, these nuclear plants will have provided almost $9 billion in avoided emissions benefits.

Reliability leaders. During full-power operations, the three reactors provide 1,770 megawatts of around-the-clock electricity for Minnesota homes and businesses. Over the last 10 years, the facilities have operated at approximately 85 percent of capacity, which is significantly higher than all other forms of electric generation. This reliable production helps offset potential price volatility of other energy sources (e.g., natural gas) and the intermittency of renewable electricity sources. Nuclear energy provides reliable electricity to businesses and consumers and helps prevent power disruptions which could lead to lost economic output, higher business costs, potential loss of jobs, and losses to consumers.

Without the carbon-free electricity produced by these nuclear plants, an additional 12 million metric tons of carbon dioxide would be released annually, the equivalent of the emissions from over 2 million cars each year.

Community and environmental leadership. Xcel Energy is a corporate leader in its neighboring communities, supporting education initiatives, environmental and conservation projects, and numerous charitable organizations.

Section 1
Background and Generation History

Monticello Nuclear Generating Plant

Dates of commercial operation
1971

Location
40 miles northwest of the Twin Cities

License Expiration Year
2030

Reactor Type
Boiling water

Total Electrical Capacity (Megawatts)
671

Prairie Island Nuclear Generating Plant

Dates of commercial operation
Prairie Island 1 - 1973
Prairie Island 2 - 1974

Location
40 Miles southeast of the Twin Cities

License Expiration Years
Prairie Island 1 - 2033
Prairie Island 2 - 2034

Reactor Type
Pressurized water

Total Electrical Capacity (Megawatts)
Prairie Island 1 - 550
Prairie Island 2 - 550

The Monticello Nuclear Generating Plant (Monticello) is located on 215-acre site in Monticello, Minnesota. It consists of a single, Boiling Water Reactor (BWR) that produces 671 MW of non-emitting baseload power.

The Prairie Island Nuclear Generating Plant (Prairie Island) is located on a 575-acre site in Red Wing, Minnesota. It consists of two Pressurized Water Reactors (PWRs) that together produce 1,100 MW of non-emitting base-load power.

Reliable Electricity Generation

Over the past decade, the three reactors operated at an average capacity factor of 85 percent. Capacity factor, a measure of electricity production availability, is the ratio of actual electricity generated to the maximum possible electric generation during the year.

Xcel Energy's nuclear plants typically generate nearly over 13 million megawatt-hours of electricity ever year. In 2015, Xcel Energy's reactors generated over 20 percent of the electricity in Minnesota. The three reactors provide enough electricity for approximately 1.4 million Minnesota households (if all of the electricity went to the residential sector).

Monticello and Prairie Island operate in the Midcontinent Independent System Operator (MISO) region, which stretches from Louisiana to Canada which covers portions of 15 states and Manitoba. Along with 14 other nuclear reactors in that operate in MISO, nuclear power keeps wholesale prices 9 percent lower in MISO than they would be without nuclear power.[1]

Thousands of High-Skilled, Well-Paying Local Jobs

Xcel Energy's nuclear operations employ nearly 1,600 full-time workers at the plants, and 140 support and executive positions at its Minneapolis headquarters. This employment supports an additional 4,200 jobs in other economic sectors in Minnesota. In total, these plants support 6,100 jobs across Minnesota (including those at the plant). The annual payroll for the direct jobs is approximately $240 million. Most jobs at nuclear power plants require technical training and are typically among the highest-paying jobs in the area. Nationwide, nuclear energy jobs pay 36 percent more than average salaries in a plant's local area according to an NEI analysis.[2]

[1] *The Nuclear Industry's Contribution to the U.S. Economy*, The Brattle Group, July 2015.

[2] *NEI Factsheet: Job Creation and Economic Benefits of Nuclear Energy.*

Safe and Clean for the Environment

Nuclear facilities generate large amounts of electricity without emitting greenhouse gases or other air pollutants. State and federal policymakers recognize nuclear energy as an essential source of safe, reliable electricity that meets both our environmental needs and the state's demand for electricity.

In 2015, the operation of these three reactors prevented the emission of 12 million metric tons of carbon dioxide,[3] about the same amount emitted by over 2 million cars each year. Overall, Minnesota's electric sector emits more than 32 million metric tons of carbon dioxide annually. The three reactors also prevent the emission of more than 11,100 tons of nitrogen oxide, equivalent to that released by 1.2 million cars, and 16,800 tons of sulfur dioxide. Sulfur dioxide and nitrogen oxide are precursors to acid rain and urban smog.

[3] *Emissions prevented are calculated using regional fossil fuel emission rates from the U.S. Environmental Protection Agency and plant generation data from the U.S. Energy Information Administration.*

Section 2
Economic Benefits in Minnesota

NEI used the REMI PI+ model to analyze economic and expenditure data provided by the plants to develop estimates of their economic benefits (more information on REMI can be found in Section 5).

The economic impacts of the Monticello and Prairie Island plants and the nuclear operations at Xcel Energy headquarters consist of direct and secondary impacts. The main variables used to analyze these impacts are:

Output
The direct output is the value of power produced by the Xcel Energy facilities. In the case of Xcel Energy's headquarters, it is the value of the nuclear support operations. The secondary output is the additional economic activity created as a consequence of the electricity generation. The direct output will impact the economic activity in other industries and how those employed at the facilities influence the demand for goods and services within the community.

Employment
The direct employment is the number of jobs at the Xcel Energy facilities. Secondary employment is the number of jobs in the other industries supported as a result of Xcel Energy's operations.

Gross State Product
Gross state product is the value of goods and services produced by labor and property at the Xcel Energy facilities—e.g., sales (i.e., output) minus intermediate goods. In the REMI model, operations is the final good from an Xcel Energy nuclear plant. Intermediate goods are the components purchased to make that electricity due to projected increases in electricity prices.

Xcel Energy's nuclear facilities are predicted to provide nearly $16 billion in economic benefits and $3.5 billion in disposable personal income benefits over the next 15 years.

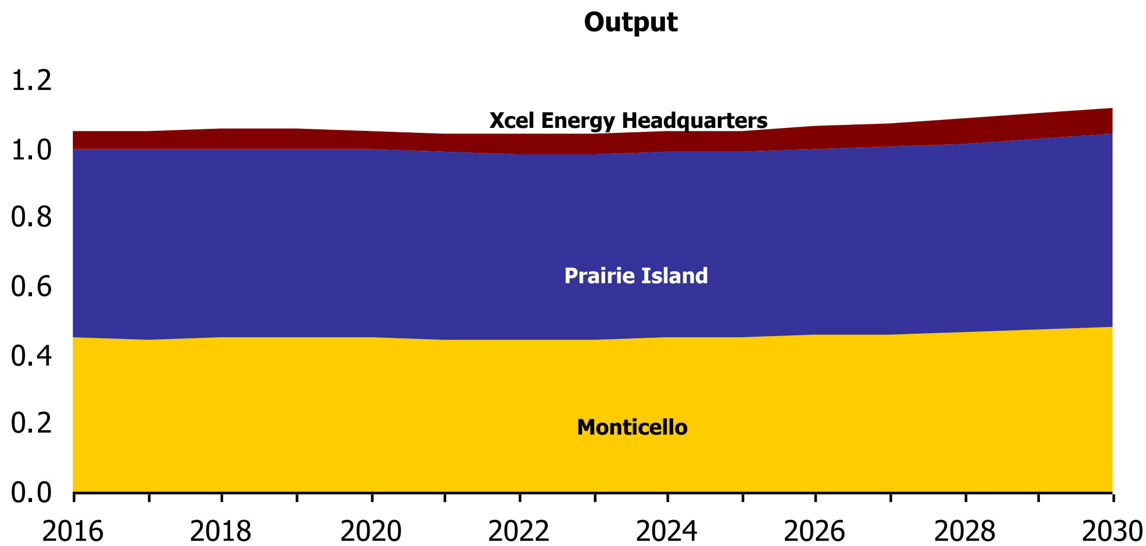
Disposable Personal Income
Disposable personal income is the total after-tax income that residents in the analyzed region would receive. This value is available for purchases on groceries and clothing or for saving and investing for the future in things like college education, retirement or a mortgage.

Substantial Economic Drivers

The direct output in 2016 of the Xcel Energy nuclear facilities were estimated to total $531 million (the value of the electricity produced at the plants), with a total economic output on the state of $1.05 billion. In other words, for every dollar of output, the state economy produced $1.98. By 2030, the total economic output is estimated to increase to $1.11 billion.

In 2016, Xcel Energy's nuclear facilities were estimated to contribute $595 million to Minnesota's gross state product (GSP) and, by 2030, the GSP stays constant at almost $600 million.

Figure 2.0
Xcel Energy Nuclear Operations' Total Output and Gross State Product Contributions to Minnesota
*(dollars in 2015 billions)**



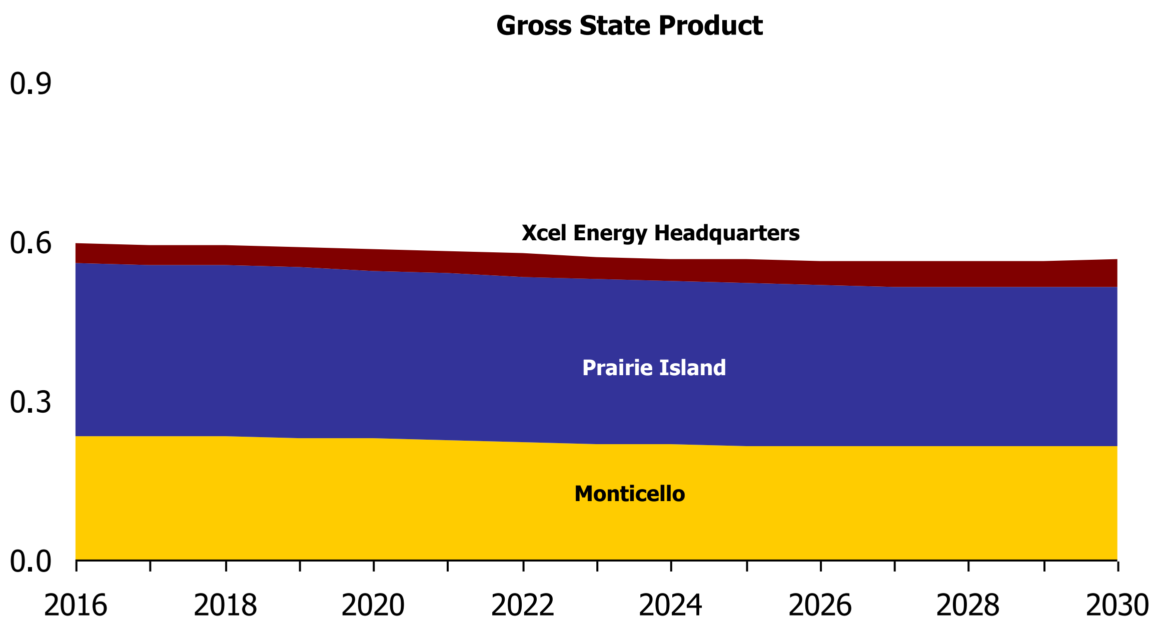


Figure 2.0 shows the value of total output and contributions to GSP from the operation of Xcel Energy's nuclear facilities through 2030, using spending data provided by Xcel Energy.

The three reactors' largest impacts are on the utilities sector, while the headquarters' greatest impact is on the corporate management sector. Xcel Energy's facilities have a substantial impact on the professional, scientific, and technical services sector—because of the volume of specialized services required to operate and maintain a nuclear power plant. Finally, there are beneficial impacts in Minnesota on the manufacturing and administrative and waste management sectors. Other sectors that benefit from the facilities' operations in Minnesota include finance and insurance, health care, retail trade, and real estate.
A full depiction of the sectors in Minnesota that benefit from the facilities is in Table 2.0.

Table 2.0
Estimated Total Output of Xcel Nuclear Operations on Minnesota's Economic Sectors in 2016 *(in millions of 2015 dollars)*

Sector Description	Monticello	Prairie Island	Xcel Energy HQ	Total
Utilities	220	311	0	531
Professional, Scientific, and Technical Services	51	52	3	106
Manufacturing	33	34	2	69
Administrative and Waste Management Services	32	32	1	65
Other Services, except Public Administration	27	28	1	56
Finance and Insurance	18	20	4	42
Management of Companies and Enterprises	3	4	31	38
Retail Trade	12	13	2	27
Health Care and Social Assistance	11	13	2	26
Real Estate and Rental and Leasing	11	12	3	26
All Other Industries	29	31	5	65
Total	**447**	**550**	**54**	**1,051**

Job Diversity and Creation

Xcel Energy's nuclear business activities stimulate the state's labor income and employment. Over 1,600 people work at Xcel Energy's nuclear plants and 140 more are employed at its Minneapolis headquarters for nuclear operations. These jobs stimulate another 4,200 jobs in other sectors in the state. All told, Xcel Energy's operations support nearly 6,100 jobs in Minnesota.

Table 2.1
Xcel Energy's Estimated Support in Direct and Secondary Jobs in Minnesota in 2016

Occupation	Monticello	Prairie Island	Xcel Energy HQ	Total
Utilities	807	870	1	1,678
Administrative and Waste Management Services	474	479	14	967
Professional, Scientific, and Technical Services	396	400	24	820
Other Services, except Public Administration	351	365	21	737
Retail Trade	159	185	33	377
Health Care and Social Assistance	133	154	25	312
Finance and Insurance	80	87	18	185
Management of Companies and Enterprises	16	17	147	180
Manufacturing	85	87	4	176
Accommodation and Food Services	64	73	16	153
Construction	66	66	2	134
Arts, Entertainment, and Recreation	34	38	9	81
Wholesale Trade	30	33	5	68
Transportation and Warehousing	28	30	4	62
Real Estate and Rental and Leasing	23	25	6	54
All Other Industries	31	37	9	77
Total	**2,777**	**2,946**	**338**	**6,061**

As discussed earlier in Section 2, the types of jobs supported by Xcel Energy's nuclear operations are diverse. Jobs supported range from office jobs in the professional, scientific, and technical services, finance and insurance, and public administration jobs to blue-collar jobs in construction and manufacturing to life-saving jobs in healthcare.

Table 2.1 details the numbers and types of jobs that Xcel Energy are supported in 2016. Xcel Energy's workers are included in the occupation categories in the table.

Economic Stimulus Through Taxes

Xcel Energy's nuclear operations resulted in an estimated annual total tax impact of $146 million to the local, state and federal governments. This includes the direct impact and secondary impacts, because plant expenditures increase economic activity, leading to additional income and value creation and, therefore, to additional tax revenue from other sectors.

Xcel Energy's impacts on the state economy are substantial. In addition to the $595 million in gross state product, the company is estimated to generate over $33 million in taxes from the plants and their activities for Minnesota and its local governments. See Table 2.2.

Extra Income for Residents

The economic activity and low-cost electricity the plants create, to which Xcel Energy's nuclear operations at its headquarters contributes, also provide a boost to incomes of residents of Minnesota. In a consumer-driven economy, this is of the utmost importance. This boost is estimated to be $237 million annually in disposable personal income greater than if the plants and headquarters did not exist. This extra income provides Minnesotans with extra money to purchase necessities such as groceries and clothing for their families or save for college or retirement. More detail of this contribution to disposable personal income is in Table 2.3.

Large Multiplier Effects for Economic Activity and Jobs

By producing affordable, reliable electricity, Xcel Energy's nuclear operations are hubs of economic activity for Minnesota. Table 2.4 provides the multipliers and summarizes the total effects from each plant. The multipliers show that for every dollar of output generated, the plants stimulate between $2.03 and $2.30 in economic output in the state, while Xcel Energy headquarters produces $1.74 for every dollar. Minnesota employment multipliers range between 3.39 and 3.44 at the plants and 2.49 at Xcel Energy headquarters.

Table 2.2
Estimated Total Tax Impacts in 2016
*(in 2015 millions of dollars)**

Facility	State and Local	Federal	Total
Monticello	12	44	56
Prairie Island	18	62	80
Xcel Energy HQ	2	7	9
Total Taxes	**33**	**113**	**146**

** Calculated based on a percentage of gross state product.*

Table 2.3
Estimated Total Personal Disposable Income Impacts in 2016
(in 2015 millions of dollars)

Facility	Total
Monticello	96
Prairie Island	116
Xcel Energy HQ	25
Total	**237**

Table 2.4
Xcel Energy's Impacts on the Minnesota Economy in 2016 *(in 2015 millions of dollars)*

Facility (Description)	Direct	Secondary	Total	Multiplier
Monticello				
Output (Utilities)	$220	$227	$447	2.03
Employment	807	1,970	2,777	3.44
Gross State Product			$232	
Prairie Island				
Output (Utilities)	$311	$239	$550	2.30
Employment	870	2,076	2,946	3.39
Gross State Product			$326	
Xcel Energy Headquarters				
Output (Management of Companies and Enterprises)	$31	$23	$54	1.74
Employment	136	202	338	2.49
Gross State Product			$37	

Section 3

Protecting the Environment

Like all nuclear power plants, Monticello and Prairie Island produce carbon-free electricity. Nuclear power produces 62 percent of the United States' carbon-free electricity and nearly 20 percent of total electricity generated. Hydro, wind and solar produce 19, 15, and 2 percent of carbon-free electricity, respectively. Nuclear power plants avoided 564 million metric tons of carbon dioxide in 2015, while hydro, wind and solar avoided 327 million metric tons combined. Annually, the avoided emissions from nuclear power is similar to adding 128 million cars to the nation's roads. Nuclear power plants also avoided hundreds of thousands of tons of nitrogen oxide and sulfur dioxide. The Environmental Protection Agency estimates that the Clean Power Plan will reduce carbon emissions by 414 million tons annually by 2030, or 73 percent of current carbon avoidance of the nuclear industry.

Xcel Energy employee holding a Peregrine Falcon chick.

Xcel Energy's Nuclear Plants Contribution

In 2015, the operation of these three reactors prevented the emission of 12 million metric tons of carbon dioxide, about the same amount emitted by over 2 million cars each year. According to the Minnesota Pollution Control Agency's most recent data from 2012, Minnesota's electric sector emitted 47.6 million tons of carbon dioxide. The three reactors also prevent the emission of more than 11,100 tons of nitrogen oxide, equivalent to that released by 1.2 million cars, and 16,800 tons of sulfur dioxide. Sulfur dioxide and nitrogen oxide are precursors to acid rain and urban smog.

Clean Air Benefits of Xcel Energy Nuclear

Monticello and Prairie Island are the two largest carbon-free sources of generation in Xcel Energy's portfolio. In 2015, Monticello and Prairie Island produced over 12 million megawatt hours of electricity which avoided the emission of 11.6 million metric tons of carbon dioxide. They also prevent the release of thousands of tons of Nitrogen Oxide and Sulfur Dioxide.

In August 2016, the U.S. Court of Appeals for the Seventh Circuit validated the Social Cost of Carbon as a legitimate method to place a value on the benefits of carbon reduction.[1] Between 2016 and 2030, assuming Monticello and Prairie Island avoid the emission of 11.6 million metric tons of CO_2 every year, these avoided emissions would represent an $8.67 billion in cumulative benefits. NEI calculated this value using the Social Cost of Carbon values from the Interagency Working Group Technical Support Document that was revised in July 2015. The values are in 2007 dollars and were inflated using the GDP deflator to 2015 dollars. The calculation is based on the 2015 carbon intensity of electricity generation in NERC's Midwest Reliability Organization.[2]

[1] Zero Zone, Inc., et al., v. U.S. Department of Energy

[2] The Minnesota Public Utilities Commission is currently updating its CO_2 externality range. Therefore, NEI has used the federal Social Cost of Carbon values as the Commission has not yet finalized its decision. The specific reference to the docket is: In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subd. 3. Minnesota Public Utilities Commission Docket No. E-999/CI-14-643.

Section 4

Community Leadership and Environmental Protection

In addition to the economic benefits that Xcel Energy's nuclear operations contribute to Minnesota in the form of jobs, income and taxes, the company and its employees contribute to local communities in many other beneficial ways. Xcel Energy strengthens Minnesota communities through hiring veterans, charitable contributions, educational programs that teach and promote the benefits of nuclear energy, environmental programs that improve the quality of the environment, and civic engagement activities that build trust and goodwill.

Children using Monticello mobile simulator at open house event.

Corporate Citizenship

At a corporate level, Xcel Energy contributes significant time and resources to charitable endeavors. Over the past 10 years, Xcel Energy has raised $2.5 million annually for the United Way. Xcel Energy matches this amount, which means over $50 million has been contributed to local communities in the past decade. This annual campaign raises money with various events such as chili cook-offs and sporting tournaments. Each year, employees, contractors and retirees continue the tradition of giving, advocating and volunteering in the community.

The 2016 United Way campaign broke all previous records with the highest combined total of donations, surpassing the goal of $3 million. The result will be more than $5.6 million in matched contributions.

Prairie Island employees volunteering at Red Wing Memorial Park.

Below are further examples of contributions of Xcel Energy and its employees:

- In September 2015, more than 3,500 volunteers pitched in and spent 10,300 hours painting, sorting, planting and otherwise supporting 80 local non-profits during Xcel Energy's fifth annual Day of Service, making it the company's largest event ever.
- The Xcel Energy Foundation awarded $3.8 million in grants to nearly 430 non-profits benefitting four community focus areas that include STEM education, economic sustainability, environmental stewardship and access to arts and culture.
- Even after they retire, former Xcel Energy employees are giving back. The Pioneers in Public Service (PIPS) retiree volunteer program has been operating for over 30 years. PIPS members have dedicated more than 80,000 volunteer hours serving in communities.

Environmental Stewardship

Xcel energy generates 55 percent of its Upper Midwest electricity using carbon-free generation. Thirty percent of that generation is from its two nuclear plants in Minnesota, 15 percent is from wind energy, and 10 percent is from a combination of hydro/biomass/solar sources. Beyond its nuclear program, Xcel Energy has been the number one utility provider of wind energy for 12 straight years.

Xcel Energy employees volunteering for Habitat for Humanity.

In 2016, the U.S. Environmental Protection Agency awarded Xcel Energy the Climate Leadership Award for achieving its self-identified goal of 20 percent reduction in carbon by 2020 (which it achieved in 2014). Xcel Energy achieved these reductions through increasing renewable energy investment, modernizing its generation fleet, and offering incentives for customers to save energy.

Employment of Veterans

In 2016, Xcel Energy set a goal of hiring veterans as 15 percent of new hires. The company exceeded this goal. Military Times Magazine rated Xcel Energy as a top company for hiring veterans. Xcel Energy was listed among the Top 100 Military Friendly Employers by GI Jobs Magazine and ranked number 8 on Monster and Miltary.com's list of best companies for veteran hiring. Also, in 2016, the Minnesota Employer Support of the Guard and Reserve recognized Xcel Energy with the Pro Patria and Above and Beyond Awards for providing beneficial leave and support rules for military members required to perform military duties.

Contributions & Sponsorships

Xcel Energy nuclear plant employees volunteer and contribute to numerous community and local organizations and events. For example, Prairie Island engages in an annual golf tournament that benefits the United Way and a Make-A-Wish summer series. Both plants support Habitat for Humanity and both the Boy and Girl Scouts of America.

Section 5

Xcel Energy Nuclear Operations and the U.S. Nuclear Energy Industry

The three reactors play a vital role in helping Minnesota meet its demand for affordable, reliable and sustainable energy.

In 2015, electricity production from U.S. nuclear power plants was about 800 billion kilowatt-hours—nearly 20 percent of America's electricity supply. In Minnesota, nuclear energy generates approximately 21 percent of the state's electricity, and Xcel Energy's three reactors generated about 13 billion kilowatt-hours of electricity, which is approximately 54 percent of Minnesota's carbon-free electricity generation.

Xcel Energy's nuclear plants provide 54 percent of the carbon-free electricity generation in Minnesota.

Over the past 25 years, America's nuclear power plants have increased output and improved performance significantly. Since 1990, the industry has increased total output equivalent to that of 26 additional 1,000-MWe nuclear power plants, when in fact only five new reactors have come online. This is due to the fact that in 1990, U.S. nuclear plants were operating approximately 66 percent of the time compared to achieving a record capacity factor of over 92 percent in 2015.

Nuclear Energy's Value Proposition

Nuclear energy's role in the nation's electricity portfolio was especially valuable during the 2014 "polar vortex," when record cold temperatures gripped the United States and other sources of electricity were forced off the grid. Nuclear power plants nationwide operated at an average capacity factor of 96 percent during the period of extreme cold temperatures. During that time, supply volatility drove natural gas prices in many markets to record highs and much of that gas was diverted from use in the electric sector so that it could be used for home heating.

Some of America's electricity markets, however, are structured in ways that place some nuclear energy facilities at risk of premature retirement, despite excellent operations. It is imperative that policymakers and markets appropriately recognize the full strategic value of nuclear energy in a diverse energy portfolio.

That value proposition starts with the safe and reliable production of large quantities of electricity around the clock.

One of nuclear energy's key benefits is the availability of low-cost fuel (which does not need to be delivered continuously and the ability to produce electricity under virtually all weather conditions.   Renewable energy, an emerging part of the energy mix, is intermittent (the sun doesn't always shine and the wind doesn't always blow when generation is needed) and therefore cannot be readily dispatched to meet demand; natural gas-fired generation depends on fuel being available (both physically and at a reasonable price); and on-site coal piles can freeze.

Nuclear power plants also provide clean-air compliance value. Minnesota's Next Generation Energy Act of 2007 set a goal that would reduce greenhouse gas emissions 15 percent below the 2005 level in 2015, and 30 and 80 percent below that level in 2025 and 2050, respectively.

Nuclear plants provide voltage support to the grid, helping to maintain grid stability. They have portfolio value, contributing to fuel and technology diversity. And they provide a tremendous local and regional economic development opportunity, including large numbers of high-paying jobs and significant contributions to the local and state economies and tax base.

Stable Prices for Consumers

Based on more than 50 years of experience, the nuclear industry is one of the safest industrial working environments in the nation.

In addition to increasing electricity production at existing nuclear energy facilities, power from these facilities is affordable and stable for consumers. Compared to the cost of electricity produced using fossil fuels—which are heavily dependent on market fuel prices—nuclear plants' fuel costs are relatively stable, making consumers' electric bills more predictable. Uranium fuel is only about one-third of the production cost of nuclear energy, while fuel costs have historically made up between 75-85 percent of coal-fired and natural gas production costs. Production costs for a nuclear plant have historically been $0.03/kWh or lower. Natural gas production costs are currently historically low at $0.03/kWh, but have been over $0.08/kWh in 2000, 2001, 2005 and 2008.

Safety and Security

Safety is the highest priority for the nuclear energy industry. Based on more than 50 years of experience, the industry is one of the safest industrial working environments in the nation. Through rigorous training of plant workers and increased communication and cooperation among nuclear plants and federal, state and local regulating bodies, the industry is keeping the nation's 99 nuclear plants safe for their communities and the environment.

The U.S. Nuclear Regulatory Commission (NRC) provides independent federal oversight of the industry and tracks data on the number of "significant events" at each nuclear plant. (A significant event is any occurrence that challenges a plant's safety systems.) The average number of significant events per reactor declined from 0.45 per year in 1990 to 0.01 in 2014, illustrating the emphasis on safety throughout the nuclear industry.

General worker safety is also excellent at nuclear power plants—far safer than in the manufacturing sector. U.S. Bureau of Labor Statistics data show that, in 2013, nuclear energy facilities achieved an incidence rate of 0.3 per 200,000 work hours, compared to 1.8 for fossil-fuel power plants, 1.8 for electric utilities and 4.0 for the manufacturing industry.

All American nuclear plants are designed and operated with public safety first and foremost in mind. The plants have redundant and diverse safety systems which are backed by multiple power sources.

U.S. nuclear plants also have over 9,000 highly trained paramilitary personnel protecting the plants from external threats. These plants also maintain emergency response plans that are reviewed and approved by the Nuclear Regulatory Commission and coordinated with the Federal Emergency Management Agency. In order to maintain this high level of safety and security within its community, each plant coordinates with its local police, fire, and EMS departments.

Industry Trends: License Renewal and New Plants

The excellent economic and safety performance of U.S. nuclear power plants has demonstrated the value of nuclear energy to the electric industry, the financial community and policymakers. This is evidenced by the increasing number of facilities seeking license renewals from the NRC.

Of the currently operating reactors nationwide, 84 out of 99 have received license renewal. The Nuclear Regulatory Commission found no technical limitations to prevent a nuclear plant from operating for 80 years.

Originally licensed to operate for 40 years, nuclear energy facilities can operate safely for longer. The NRC granted the first 20-year license renewal to the Calvert Cliffs plants in Maryland in 2000. As of March 2017, 84 currently operating reactors had received license extensions, and operators of 13 additional reactors either had submitted applications or announced that they will seek renewal. License renewal is an attractive alternative to building new electric capacity because of nuclear energy's low production costs and the return on investment provided by extending a plant's operational life.

The Nuclear Regulatory Commission has found that there are no technical reasons to prevent a nuclear plant from operating for 80 years. In 2014, the Nuclear Regulatory Commission found that its current regulatory structure regarding initial license renewal is suitable for second license renewal. In 2015, Dominion announced that it will apply in 2019 for a second license renewal for its Surry Power Station in Virginia. If granted, this will allow the plant to operate for an additional 20 years (80 years in total). Exelon announced in June 2016 that it will pursue second license renewal for its Peach Bottom plant.

Besides relicensing nuclear plants, energy companies are building new, advanced-design reactors. Georgia Power and South Carolina Electric & Gas are building two advanced reactors each, near Augusta, Ga., and Columbia, S.C. These facilities are nearly halfway through their construction programs. These projects employ more than 5,000 workers each now that construction is peaking. In addition, Tennessee Valley Authority began operation of the Watts Bar 2 reactor in Tennessee in June 2016.

Section 6
Economic Impact Analysis Methodology

This analysis uses the REMI model to estimate the economic and fiscal impacts of Xcel Energy's nuclear facilities.

Regional Economic Models, Inc. (REMI)

REMI is a modeling firm specializing in services related to economic impacts and policy analysis, headquartered in Amherst, Mass. It provides software, support services, and issue-based expertise and consulting in almost every state, the District of Columbia, and other countries in North America, Europe, Latin America, the Middle East and Asia.

REMI's software has two main purposes: forecasting and analysis of alternatives. All models have a "baseline" forecast of the future of a regional economy at the county level. Using "policy variables," in REMI terminology, provides scenarios based on different situations. The ability to model policy variables makes it a powerful tool for conveying the economic "story" behind policy. The model translates various considerations into understandable concepts like GDP and jobs.

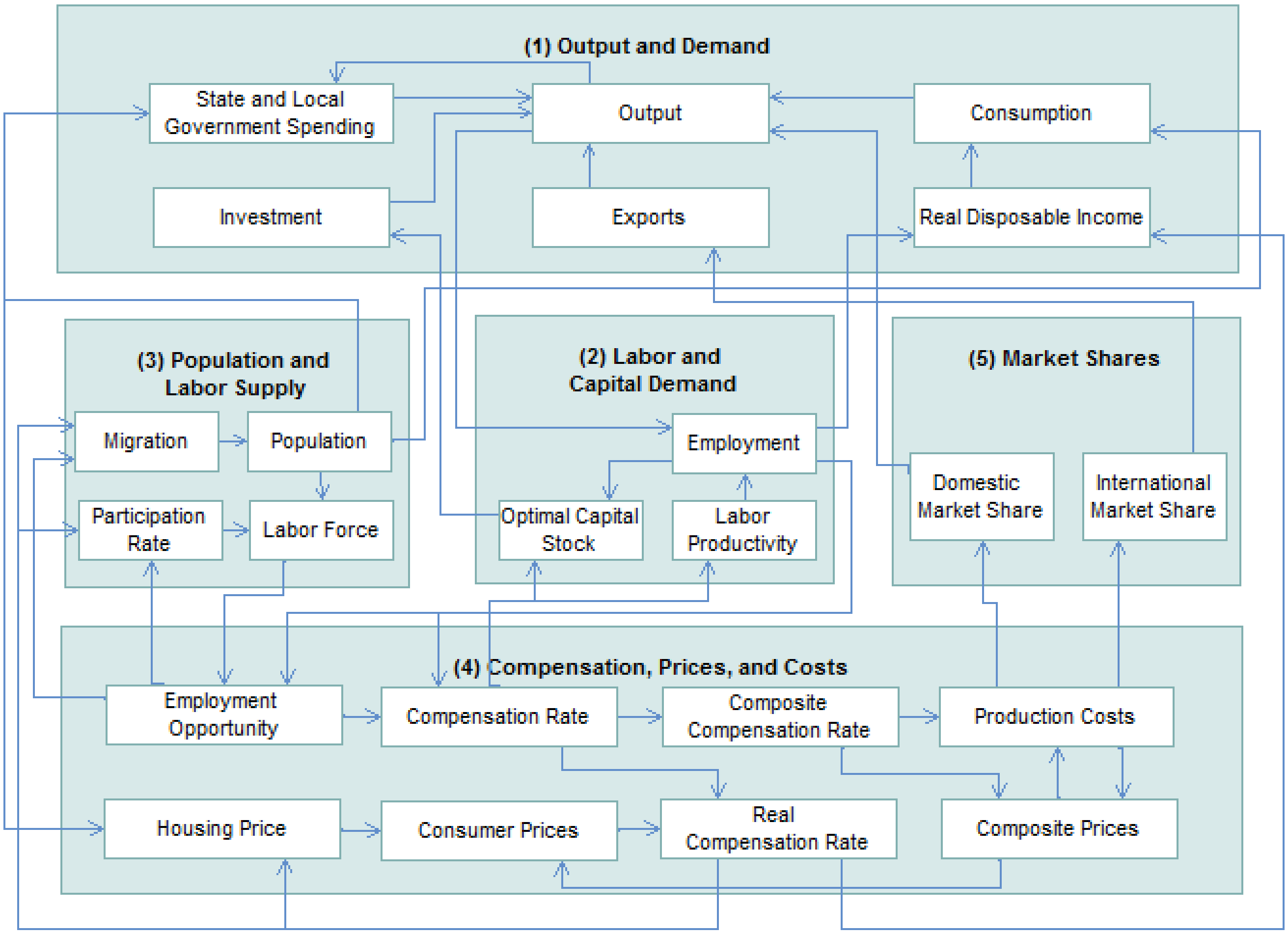
REMI relies on data from public sources, including the Bureau of Economic Analysis, Bureau of Labor Statistics, Energy Information Administration and the Census Bureau. Forecasts for future macroeconomic conditions in REMI come from a combination of resources, including the Research Seminar in Quantitative Economics at the University of Michigan and the Bureau of Labor Statistics. These sources serve as the main framework for the software model needed to perform simulations.

Policy Insight Plus (PI+)

REMI's PI+ is a computerized, multiregional, dynamic model of the states or other sub-national units of the United States economy. PI+ relies on four quantitative methodologies to guide its approach to economic modeling:

1. Input/output tabulation (IO)—IO models, sometimes called "social accounting matrices" (SAM), quantify the interrelation of industries and households in a computational sense. It models the flow of goods between firms in supply-chains, wages paid to households, and final consumption by households, government and the international market. These channels create the "multiplier" effect of $1 going farther than when accounting for its impact on enabling subsequent value..
2. Computable general equilibrium (CGE)—CGE modeling adds market concepts to the IO structure. This includes how those structures evolve over time and how they respond to alternative policies. CGE incorporates con-

Figure 6.0



This diagram represents the structure and linkages of the regional economy in PI+. Each rectangle is a discrete, quantifiable concept or rate, and each arrow represents an equation linking the two of them. Some are complex econometric relationships, such as the one for migrant, while some are rather simple, such as the one for labor force, which is the population times the participation rate. The change of one relationship causes a change throughout the rest of the structure because different parts move and react to incentives at different points. At the top, Block 1 represents the macroeconomic whole of a region with final demand and final production concepts behind GDP, such as consumption, investments, net exports and government spending. Block 2 forms the "business perspective": An amount of sales orders arrive from Block 1, and firms maximize profits by minimizing costs when making optimal decisions about hiring (labor) and investment (capital). Block 3 is a full demographic model. It has births and deaths, migration within the United States to labor market conditions, and international immigration. It interacts with Block 1 through consumer and government spending levels and Block 4 through labor supply. Block 4 is the CGE portion of the model, where markets for housing, consumer goods, labor and business inputs interact. Block 5 is a quantification of competitiveness. It is literally regional purchase coefficients (RPCs) in modeling and proportional terms, which show the ability of a region to keep imports away while exporting its goods to other places and nations.

cepts on markets for labor, housing, consumer goods, imports and the importance of competitiveness to fostering economic growth over time. Changing one of these will influence the others—for instance, a new knife factory would improve the labor market and then bring it to a head by increasing migration into the area, driving housing and rent prices higher, and inducing the market to create a new subdivision to return to "market clearing" conditions.

3. Econometrics—REMI uses statistical parameters and historical data to populate the numbers inside the IO and CGE portions. The estimation of the different parameters, elasticity terms and figures gives the strength of various responses. It also gives the "time-lags" from the beginning of a policy to the point where markets have had a chance to clear.

4. New economic geography—Economic geography provides REMI a sense of economies of scale and agglomeration. This is the quantification of the strength of clusters in an area and their influence on productivity. One example would include the technology and research industries in Seattle. The labor in the area specializes to serve firms like Amazon and Microsoft and, thus, their long-term productivity grows more quickly than that of smaller regions with no proclivity towards software development (such as Helena, Mont.). The same is true on the manufacturing side with physical inputs, such as with the supply-chain for Boeing and Paccar in Washington in the production of transportation equipment. Final assembly will have a close relationship and a high degree of proximity to its suppliers of parts, repairs, transportation and other professional services, which show up in clusters in the state.

Conclusion

The estimated total economic impacts (direct and secondary) to Minnesota from Xcel Energy's nuclear operations at its three reactors and support operations at Xcel Energy headquarters are over $1 billion in output and approximately $600 million in gross state product every year. These operations also contribute $240 million in after-tax income to residents of Minnesota. The nuclear operations and their secondary effects also account for over 6,000 jobs in Minnesota.

The plant's economic benefits—on taxes and through wages and purchases of supplies and services—are considerable. In addition, plant employees further stimulate the local economy by purchasing goods and services from businesses around the area, supporting many small businesses throughout the region.

The facilities generated nearly 13 billion kilowatt-hours of emission-free electricity in 2015, enough to serve the yearly needs for 1.4 million homes. This low-cost, reliable electricity helped keep electricity prices in check in Minnesota.

Xcel Energy's nuclear plants are leaders economically, fiscally, environmentally and socially within Minnesota.

■

Nuclear Fuel Process

The following summarizes how nuclear fuel expenditures and additions are determined.

Commodities - Nuclear fuel commodities (uranium, uranium conversion services and uranium enrichment services) are purchased as needed under contracts in force at the time of purchase to meet future reload specific energy requirements. These commodities are fungible. The uranium content of the new nuclear fuel assemblies received are provided by the nuclear fuel fabrication vendor at the time the new nuclear fuel assemblies are shipped to the nuclear plant site.

Processing - Each processing stage (uranium mining, uranium conversion services, uranium enrichment services and fuel assembly fabrication) in the nuclear fuel construction period has contractually agreed upon lead times for the delivery of the prior processing stage's unfinished nuclear materials. Consequently, a typical construction period for new nuclear fuel assemblies ranges from 18 months to 24 months.

Service Providers - Westinghouse Electric Co., LLC provided or will provide the nuclear fuel fabrication and engineering services required to manufacture the new nuclear fuel assemblies placed in service during the years 2018 through 2022 for the Prairie Island Nuclear Generating Plant. Framatome Inc. provided or will provide the nuclear fuel fabrication and engineering services required to manufacture the new nuclear fuel assemblies placed in service in 2018 through 2022 for the Monticello Nuclear Generating Plant.

Cost Accounting - Nuclear fuel commodities are assigned to the new nuclear fuel assemblies at average unit cost when they arrive at the nuclear plant site based on the uranium content in the new nuclear fuel assemblies. Current year nuclear fuel commodity expenditures may remain in the nuclear fuel construction in process accounts for up to two years before assignment to a specific nuclear fuel reload (at average cost of all fuel in-process), at which time they are classified as completed construction through a capital addition to plant in service. Reload fabrication and engineering costs are specifically identifiable and assigned to each new nuclear fuel reload.

Nuclear Fuel Expenditures and Costs of Reloads Being Amortized

The following summarizes nuclear fuel capital expenditures and costs of completed fuel reloads beginning amortization for the years shown:

Xcel Energy Nuclear Fuel *$ in millions*	**Actual 2018**	**Forecast 2019**	**Budget 2020**	**Prelim 2021**	**Prelim 2022**
Capital Expenditures (excluding AFUDC) – Table NF-1	$62.7	$125.7	$54.5	$102.4	$88.5
Completed Reload Costs Beginning Amortization – Tables NF-2 (summary) & NF-3 (detail)	$81.8	$156.2	$84.4	$152.2	$74.2

The differences in reload expenditures and completed reload costs beginning amortization each year are driven by variations in the number of reactors and the specific reactors refueled in each year, and which reloads are in process vs. completed in each year. Similarly, expenditures in a given year may vary significantly from other years based on ongoing expenditures for commodities and processing needed for upcoming reload requirements planned for each unit.

- Monticello operates on a 2-year cycle and is planning reloads every other year, in 2019 and 2021.
- Prairie Island operates on a 2-year cycle and would have one reload for each of its units every other year, resulting in one reload completed for the site each year.

The components of annual capitalized expenditures, excluding AFUDC, charged to nuclear fuel construction in process for the years 2018 through 2022 are provided in the attached Table NF-1.

The number of fuel assemblies, average costs of fuel assemblies, and all other costs that make up the completed nuclear fuel reloads moved from construction in process accounts and beginning amortization are provided in the attached Tables NF-2 (summary) and NF-3 (detail). Note that there can be timing differences between the date the fuel assemblies are placed in service as a capital addition and the date they begin use in the reactor for fuel amortization purposes. Nuclear fuel expense amortization begins when the reloaded fuel is in the reactor and being consumed from the unit being online.

Dollars in Millions

Table NF-1: Annual Nuclear Fuel Capital Expenditures - Direct (exluding AFUDC)

Cost Component	Actual 2018	Projected 2019	Projected 2020	Projected 2021	Projected 2022	Total 2018-2022
Uranium	$ 18.4	$ 45.0	$ 12.5	$ 35.6	$ 26.2	$ 137.6
Conversion	2.8	9.0	4.4	6.1	5.1	27.5
Enrichment	30.4	45.8	21.2	33.6	42.2	173.3
Fabrication	8.0	18.9	9.2	19.2	9.0	64.2
Labor	1.5	1.7	1.5	1.7	1.7	8.1
Engineering	1.6	5.2	5.7	6.2	4.4	23.1
Total	**$ 62.7**	**$ 125.7**	**$ 54.5**	**$ 102.4**	**$ 88.5**	**$ 433.8**

Dollars in Millions

Table NF-2: Summary - Costs of Completed Nuclear Fuel Reloads Beginning Amortization

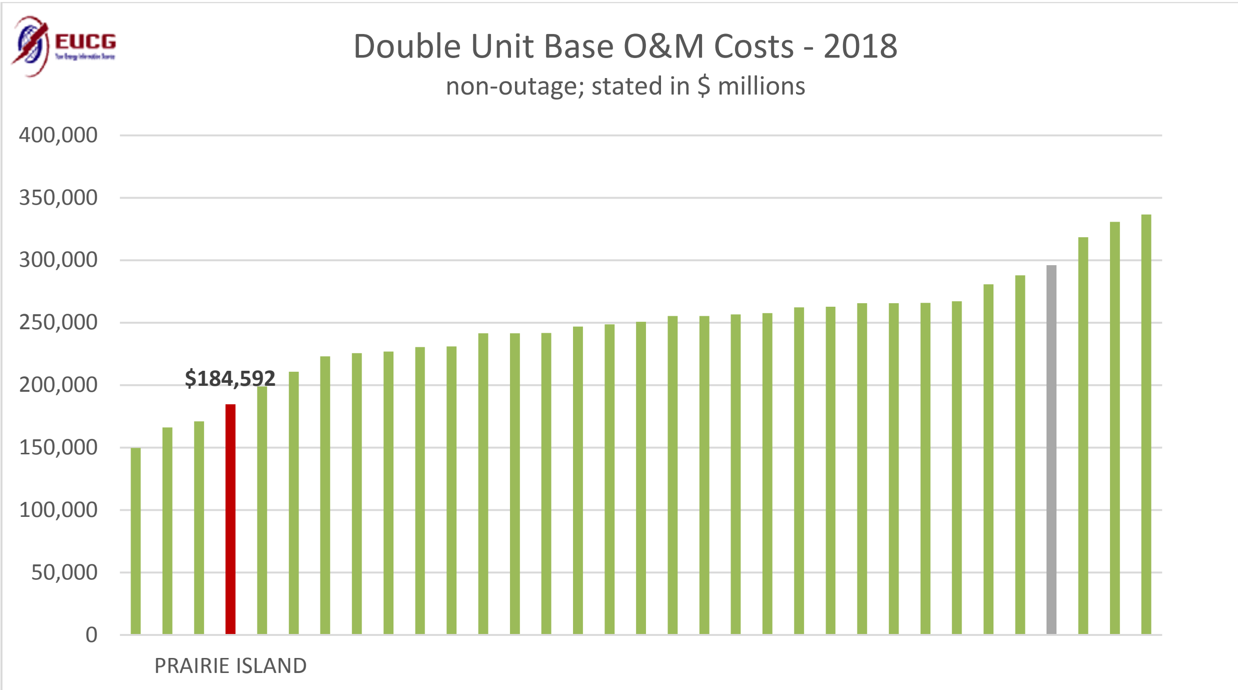
Reload	Actual 2018	Projected 2019	Projected 2020	Projected 2021	Projected 2022	Total 2018-2022
PI1 Cycle 31	$ 81.8					$ 81.8
Monticello Cycle 30		$ 81.1				$ 81.1
PI2 Cycle 31		$ 75.1				$ 75.1
PI1 Cycle 32			$ 84.4			$ 84.4
Monticello Cycle 31				$ 77.3		$ 77.3
PI2 Cycle 32				$ 74.9		$ 74.9
PI1 Cycle 33					$ 74.2	$ 74.2
Other						$ -
Total	**$ 81.8**	**$ 156.2**	**$ 84.4**	**$ 152.2**	**$ 74.2**	**$ 548.8**

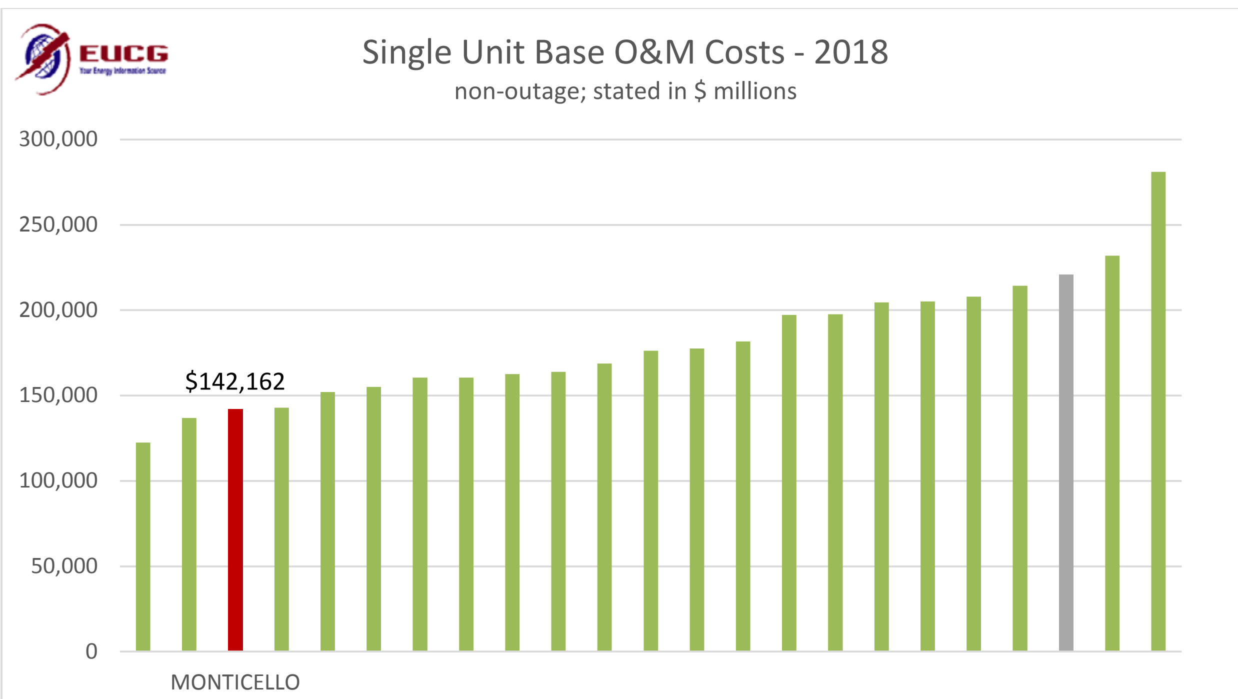
Table NF-3: Detail of Completed Nuclear Fuel Reload Costs Beginning Amortization - 2018 through 2022 ($ in millions)

Unit & cycle	Year In-Service	Batch ID	Assemblies	Average wt% U235	Average Kg U/Assembly	Uranium	Conversion	Enrichment	Fabrication	Labor	Engineering	AFUDC	A&G	Reload Total	Average $/Assembly
PI 1 Cycle 31	2018	131A	20	4.8927	394.709	$ 10.9	$ 1.1	$ 8.3	$ 2.8	$ 0.6	$ 2.1	$ 3.2	$ 0.0	$ 29.1	$ 1.45
		131B	20	4.9211	394.925	$ 11.0	$ 1.1	$ 8.4	$ 2.8	$ 0.6	$ 2.1	$ 3.2	$ 0.0	$ 29.2	$ 1.46
		131C	16	4.9476	395.342	$ 8.8	$ 0.9	$ 6.8	$ 2.3	$ 0.5	$ 1.7	$ 2.6	$ 0.0	$ 23.5	$ 1.47
			56	4.9185	**394.967**	$ 30.7	$ 3.1	$ 23.5	$ 8.0	$ 1.6	$ 5.8	$ 9.1	$ 0.1	**$ 81.8**	$ 1.46
Monticello Cycle 30	2019	330A	28	3.9612	176.380	$ 5.0	$ 0.5	$ 4.5	$ 1.8	$ 0.2	$ 0.4	$ 0.9	$ 0.0	$ 13.2	$ 0.47
		330B	88	4.0549	176.346	$ 16.2	$ 1.7	$ 14.5	$ 5.6	$ 0.5	$ 1.3	$ 2.7	$ 0.0	$ 42.6	$ 0.48
		330C	52	4.0588	176.940	$ 9.6	$ 1.0	$ 8.6	$ 3.3	$ 0.3	$ 0.8	$ 1.6	$ 0.0	$ 25.3	$ 0.49
			168	4.0405	**176.535**	$ 30.8	$ 3.2	$ 27.6	$ 10.7	$ 1.0	$ 2.5	$ 5.2	$ 0.0	**$ 81.1**	$ 0.48
PI 2 Cycle 31	2019	231A	8	4.7501	393.800	$ 3.9	$ 0.5	$ 3.3	$ 1.2	$ 0.1	$ 0.3	$ 0.8	$ 0.0	$ 10.1	$ 1.26
		231B	28	4.9242	394.100	$ 15.4	$ 1.8	$ 11.3	$ 4.0	$ 0.5	$ 0.9	$ 3.2	$ 0.0	$ 37.2	$ 1.33
		231C	20	4.9500	394.500	$ 10.7	$ 1.2	$ 8.5	$ 2.9	$ 0.4	$ 0.6	$ 2.2	$ 0.0	$ 26.5	$ 1.33
		231D	1	4.7501	393.800	$ 0.5	$ 0.1	$ 0.4	$ 0.1	$ 0.0	$ 0.0	$ 0.1	$ 0.0	$ 1.3	$ 1.28
			57	4.9058	**394.193**	$ 30.6	$ 3.6	$ 23.5	$ 8.2	$ 1.0	$ 1.8	$ 6.4	$ 0.0	**$ 75.1**	$ 1.32
PI1 Cycle 32	2020	132A	12	4.7499	394.872	$ 6.4	$ 0.8	$ 4.9	$ 1.8	$ 0.2	$ 0.5	$ 2.0	$ 0.0	$ 16.6	$ 1.38
		132B	4	4.8000	395.801	$ 2.2	$ 0.3	$ 1.6	$ 0.6	$ 0.1	$ 0.2	$ 0.7	$ 0.0	$ 5.6	$ 1.40
		132C	4	4.8724	394.409	$ 2.2	$ 0.3	$ 1.7	$ 0.6	$ 0.1	$ 0.2	$ 0.7	$ 0.0	$ 5.7	$ 1.42
		132D	8	4.8983	394.872	$ 3.9	$ 0.5	$ 3.8	$ 1.2	$ 0.1	$ 0.3	$ 1.3	$ 0.0	$ 11.2	$ 1.40
		132E	20	4.9242	395.338	$ 9.8	$ 1.3	$ 9.6	$ 3.1	$ 0.3	$ 0.8	$ 3.3	$ 0.0	$ 28.1	$ 1.41
		132F	12	4.9500	395.801	$ 6.6	$ 0.8	$ 5.2	$ 1.8	$ 0.2	$ 0.5	$ 2.1	$ 0.0	$ 17.3	$ 1.44
			60	4.8794	**395.244**	$ 31.1	$ 4.0	$ 26.8	$ 9.2	$ 0.9	$ 2.3	$ 10.1	$ 0.0	**$ 84.4**	$ 1.41
Monticello Cycle 31	2021	331A	28	3.9584	176.578	$ 4.5	$ 0.7	$ 4.3	$ 1.8	$ 0.2	$ 0.5	$ 1.3	$ 0.0	$ 13.3	$ 0.47
		331B	84	4.0520	176.577	$ 13.8	$ 2.1	$ 13.3	$ 5.4	$ 0.5	$ 1.5	$ 4.0	$ 0.0	$ 40.7	$ 0.48
		331C	48	4.0573	177.129	$ 7.9	$ 1.2	$ 7.7	$ 3.1	$ 0.3	$ 0.9	$ 2.3	$ 0.0	$ 23.4	$ 0.49
			160	4.0372	**176.743**	$ 26.2	$ 4.0	$ 25.3	$ 10.4	$ 1.0	$ 2.9	$ 7.6	$ 0.0	**$ 77.3**	$ 0.48
PI 2 Cycle 32	2021	232A	12	4.7499	394.872	$ 6.3	$ 1.0	$ 4.6	$ 1.9	$ 0.2	$ 0.4	$ 1.4	$ 0.0	$ 15.7	$ 1.31
		232B	24	4.8983	394.872	$ 11.9	$ 1.8	$ 10.4	$ 3.8	$ 0.5	$ 0.8	$ 2.7	$ 0.0	$ 31.9	$ 1.33
		232C	4	4.9242	395.338	$ 2.0	$ 0.3	$ 1.8	$ 0.6	$ 0.1	$ 0.1	$ 0.5	$ 0.0	$ 5.3	$ 1.33
		232D	16	4.9500	395.801	$ 8.8	$ 1.4	$ 6.5	$ 2.5	$ 0.3	$ 0.6	$ 1.9	$ 0.0	$ 21.9	$ 1.37
			56	4.8832	**395.171**	$ 28.9	$ 4.5	$ 23.2	$ 8.8	$ 1.1	$ 2.0	$ 6.5	$ 0.0	**$ 74.9**	$ 1.34
PI1 Cycle 33	2022	133A	4	4.8983	322.456	$ 2.0	$ 0.3	$ 1.5	$ 0.6	$ 0.1	$ 0.1	$ 0.6	$ 0.0	$ 5.3	$ 1.33
		133B	36	4.9242	395.338	$ 16.9	$ 2.7	$ 15.0	$ 5.8	$ 0.8	$ 1.3	$ 4.9	$ 0.0	$ 47.5	$ 1.32
		133C	16	4.9500	395.801	$ 7.9	$ 1.3	$ 6.5	$ 2.6	$ 0.3	$ 0.6	$ 2.2	$ 0.0	$ 21.4	$ 1.34
			56	4.9297	**395.437**	$ 26.8	$ 4.4	$ 23.1	$ 9.0	$ 1.2	$ 2.0	$ 7.7	$ 0.0	**$ 74.2**	$ 1.32

Nuclear Operations Business Area Non-Outage O&M Costs
($ in millions)

$ in millions	2016 Actual	2017 Actual	2018 Actual	2019 Fcst	2020 Test Year Budget	2021 Test Year Budget	2022 Test Year Budget	Avg Chg per Year 2016 to 2018	Avg Chg per Year 2018 to 2020	Avg Chg per Year 2016 to 2022
Workforce Costs										
A. Internal Labor	$143.60	$139.20	$135.10	$135.90	$139.40	$143.20	$146.90	-3.00%	1.60%	0.40%
B. External Labor										
(Contractors & Consultants)	31.7	23.3	27.9	28.1	19.9	25.4	22.6	-3.30%	-14.30%	-3.10%
C. Security	34	33	31.2	31.2	31.1	30.1	30.4	-4.20%	-0.20%	-1.80%
Subtotal Workforce Costs	209.3	195.4	194.3	195.2	190.4	198.7	199.8	-3.60%	-1.00%	-0.70%
Non-Workforce Costs										
D. Materials & Chemicals	18	13.7	15.4	11.8	13.4	13.4	13.3	-5.60%	-4.90%	-3.60%
E. Employee Expenses	3.5	3.2	3.3	3.2	3.5	3.5	3.5	-2.70%	3.20%	0.10%
F. Nuclear-related fees	35.8	34.1	34	36.8	37.1	37.5	37.9	-2.50%	4.50%	1.00%
G. Other	6	6.5	7.7	6.5	5.9	5.9	6	13.40%	-12.00%	0.70%
Subtotal Non-Workforce Costs	63.2	57.6	60.4	58.3	59.9	60.2	60.7	-2.00%	-0.30%	-0.60%
Total Non-Outage O&M	**$272.50**	**$253.00**	**$254.70**	**$253.50**	**$250.30**	**$258.90**	**$260.50**	**-3.20%**	**-0.90%**	**-0.70%**


EUCG
Double Unit Base O&M Costs - 2018
non-outage; stated in $ millions
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
$184,592
PRAIRIE ISLAND


EUCG
Single Unit Base O&M Costs - 2018
non-outage; stated in $ millions
300,000
250,000
200,000
150,000
100,000
50,000
0
$142,162
MONTICELLO

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

Last Updated: November 28, 2007

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

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Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

Statement of Purpose

This accounting policy addresses the operations and maintenance (O&M) expenditures that are associated with the routine refueling of a nuclear unit and are categorized as planned major maintenance activities. Please refer to the attached list of definitions for any terminology used in this policy. Xcel Energy's utility subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC) and by various state commissions. All of the utility subsidiaries' accounting records must conform to the FERC Uniform System of Accounts. Additionally, Xcel Energy is subject to regulation by the Securities and Exchange Commission (SEC).

The overall goal of this document is to achieve a consistent policy that defines common procedures to ensure correct and consistent accounting that complies with FERC guidelines and SEC regulations for the proper handling of planned major maintenance activities associated with routine nuclear refueling across all applicable entities. It is common practice across the industry to allow expenditures to be charged to a deferred work order associated with a routine nuclear refueling in order to amortize the costs over the next fuel cycle. Due to the magnitude of this issue, it is necessary that the proper accounting be defined to assure accurate books and records of the Company. Currently, Northern States Power Company, a Minnesota corporation (NSPM) is the only Xcel Energy operating company with nuclear facilities, but the policy would apply to any subsidiary with such facilities.

Applicability

This Uniform Policy is effective on the date stated below and on that date, this policy became effective for all utility subsidiary companies. This Uniform Policy is applicable to all Xcel Energy utility subsidiaries that deal with nuclear facilities.

Summary

Because Xcel Energy is regulated by various government entities, the Corporate Controller is responsible for accounting policies for Xcel Energy within the framework of the SEC, FASB, FERC, and state regulatory requirements. These policies will include establishing and maintaining effective internal controls as it relates to the books and records of Xcel Energy and the preparation of all consolidated external reports as required by the SEC, FERC, and the state regulators.

Within this framework, Regulatory Accounting will establish appropriate accounting policies in order to meet the FERC and GAAP/SEC accounting requirements. At the end of each month, in order to recognize the regulatory assets correctly on the Company's balance sheet and to provide for the proper amortization to the income statement, only those refueling O&M expenditures that satisfy the criteria defined herein should be recognized to the appropriate deferred work orders.

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

This policy defines the expectations surrounding treatment of routine refueling O&M expenditures as planned major maintenance activities that should be charged to deferred work orders to assure proper internal controls are in place and a proper audit trail exists. Where allowed by a regulatory jurisdiction, the deferral and subsequent amortization of these expenditures meet the guidance issued under FASB Staff Position No. AUG AIR-1 (FSP AUG AIR-1), *Accounting for Planned Major Maintenance Activities*. It is Regulatory Accounting's responsibility to maintain this policy and to ensure, in conjunction with the business unit personnel, consistent application of the procedures contained in the policy. Regulatory Accounting will monitor FERC regulations and other accounting rules that impact this policy and make changes as necessary to maintain accounting compliance. Thus, business areas are responsible to understand and to adhere to the policy. Regulatory Accounting will assist business areas to appropriately apply the policy.

Definitions

Capital – The purchase or construction of a retirement unit that will be recorded on the balance sheet as an asset after meeting the GAAP criteria for being an asset

FASB – Financial Accounting Standards Board

FERC – Federal Energy Regulatory Commission

FSP – FASB Staff Position

GAAP – Generally Accepted Accounting Principles

O&M Expenditure – Expenditure incurred in the normal operations of the assets or restores the fixed asset to operating status and assists in assuring that the fixed assets achieve useful life expectations

SEC – Securities and Exchange Commission

Work Order – An account numbering system used to group costs (often referred to as a subledger in the JD Edwards general ledger system)

Content

Characterization

This policy is based on the FSP AUG AIR-1 that modifies certain positions of AICPA Industry Audit Guide, Audits of Airlines, which defines three allowable treatments for planned major maintenance activities: direct expense, built-in overhaul, or deferral. Xcel Energy uses two methods: direct expensing and deferral with an amortization, often referred to as a "deferral-and-amortization method". The deferral-and-amortization method is used only when authorized by a specific regulatory jurisdiction. Thus, if no approval exists for a specific jurisdiction, the jurisdiction must use the direct expense method. As the costs for planned major maintenance activities provide value to the constructed asset over the next cycle to which the refueling relates (typically the next 18 to 24

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

months), the deferral-and-amortization method has the benefit of better matching costs to the period in which it relates. These costs include, but are not limited to; contract labor, company labor and benefits, materials and supplies, transportation, machine equipment, tool usage, permits, equipment rental, taxes, and various incurred for planned major maintenance activities such as cleaning, servicing, replacement, or repair, as well as costs of replacement components, minor parts, and interactive agents (such as certain fluids or elements).

In general, those nuclear refueling outage costs that are properly includable to a regulatory asset under the deferral-and-amortization method should be charged to the appropriate reload-specific set of deferred work orders. A series of deferred work orders will be established for each reload to align with the applicable FERC Account to which the O&M cost would have been charged if it had been expensed, such that the amortization is expensed to those same O&M FERC Accounts. Any work done during a refueling outage that meets the requirements for capitalization is not includable in the deferred work orders. In addition, costs for standard maintenance or normal operations, which occur during a refueling outage and which are **not** listed in the definition of includable expenses shown below, are to be expensed to the appropriate O&M accounts. This policy defines the expenses allowed to the deferred work orders established for refueling outage costs and helps one understand the limits in the use of these deferred work orders.

Definition

Nuclear reactors are typically shut down once every 18 to 24 months to refuel approximately one third of the reactor core. There are many costs associated with a refueling outage. These include the following O&M costs:

- Replacement of approximately one third of the nuclear fuel assemblies in the reactor core;
- Numerous inspections on equipment to ensure safety and compliance with requirements;
- Test and maintenance jobs that can be performed only when the reactor is shut down; and
- Repairs and refurbishment of major nuclear and non-nuclear components of the plant (e.g., control rods, main coolant pumps, steam generators, turbine valves and blading, main electric generator).

This is a general list of items. However, other costs arise during a refueling outage that may be appropriate for deferral and amortization. Such costs may only be deferred following a review of the new charges for compliance with this policy and, upon compliance, approval by the outage manager and the site accounting manager (with retention of the appropriate documentation). If work begins on these activities prior to receiving approval, the expenditures will be treated as an O&M expense. However, certain costs occurring before and after the actual period when the unit is off-line are allowable to deferred work orders. Descriptions of allowed pre-outage costs and post-outage costs are included below.

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

In addition to the work performed in a "base" refueling outage, more extensive work is required during refueling outages, usually staggered over a 10-year period, to comply with periodic Nuclear Regulatory Commission (NRC) and insurance requirements. In addition, it is anticipated that more extensive refueling outages occasionally will be needed as larger projects are completed. These more extensive outages will require longer periods and higher costs than typical refueling outages, but are one-time expenses not anticipated to be repeated over the license renewal period. Because each unit has different operating characteristics and parameters, each has its own fuel cycle, ranging from 18 to up to 24 months. Thus, the number of refueling outages scheduled in any given year will vary, with two outages occurring in most years, one in others, and the potential for even three refueling outages occurring in some years. Extensive planning goes into the preparation and execution of these outage schedules.

The deferral-and-amortization method of accounting will include only costs directly associated with a planned refueling outage. All other work, albeit done at the time of the outage, will be directly charged to the appropriate O&M or capital accounts as has been traditionally done. Planned outage costs for the next refueling can begin soon after the unit returns to service as contracts are being set and material is being ordered. However, most of the costs associated with planned outage work occur within the actual outage period. An activity or work order is considered planned outage work if one of the following conditions applies:

- The plant impact of the work scope requires an outage to complete;
- The work scope is required by Technical Specifications, license-based provisions, or other regulatory requirements to be performed during the outage timeframe;
- The work scope duration required exceeds greater than 75% limited condition operations ("LCO") duration;
- The work scope requires a preventative maintenance test ("PMT") or a test that can only be performed during an outage, and the work that is required ensures unit reliability for the next cycle.

Pre-outage Costs

As with any large project, capital or maintenance, there is considerable planning that occurs in order for the outage to be as efficient as possible. These planning costs are allowed as part of the deferred work order even if the costs occur in a prior year. The earliest that outage costs can occur is shortly after the unit comes on-line from the last outage. Costs cannot be deferred that occur any earlier than the beginning of the operating cycle immediately before the outage being planned.

Allowable costs during the pre-outage period include the following:

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

- Outage milestone planning to develop a systematic approach for preparing for an outage;
- Surveillance and special testing of equipment;
- Any work issues identified for performance prior to a planned outage.

As with all the costs, proper documentation must exist to support the appropriateness of the charge to the FERC specific deferred work order. Any charge that does not meet the above requirements should be charged directly, in the current period, to the appropriate O&M account.

Post-outage Costs

Typically, costs continue to come in throughout the month following the return to service. This is expected, however any costs that are known and measurable in the month when the unit returns to service should be recorded as an unvouchered liability in that month. The month when the bill is received will then contain a reversal of the unvouchered liability and recognition of the actual expense. This true up from estimate to actual is often referred to as a "pick up".

Allowable costs during the post-outage period include the following:

- Resolution of disputed outage contractor issues;
- Delay charges;
- Costs associated with the removal of equipment to support outage activities.

As with all the costs, proper documentation must exist to support the appropriateness of the charge to the FERC specific deferred work order. Any charge that does not meet the above requirements should be charged directly, in the current period, to the appropriate O&M account.

Non-outage Costs

Non-outage activities may be added to the outage schedule based on work benefits that can be gained by delaying the work until the outage. Although this work is performed at the same time as the refueling outage, it is not included in the deferral and amortization. This includes the following, but is not limited to these examples:

- Personnel exposure to radiation that can be measurably reduced by performing the work when the unit is shutdown rather than at power assuming the work can be deferred to a planned outage;
- Regular maintenance work on the same component that is scheduled for work during the outage and the work can be safely delayed until the outage;

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- Work based on economic considerations and surveillance or preventative maintenance tasks that are scheduled during the outage period and cannot be rescheduled outside of the outage period.

Unplanned Outage Costs

Unplanned outages include the work that cannot be delayed until the next planned outage and requires the unit to be shutdown in order for the work to be completed. Also included in unplanned outages is any work done when the unit is brought off line for safety reasons. Costs related to these unplanned outages, as well as all non-outage activity costs, are not eligible for the deferral-and-amortization method of accounting, and will continue to use the direct expense accounting method.

<u>Accounting</u>

Deferred Work Order

Each outage for each unit is assigned a separate set of FERC specific deferred work orders. Before the first refueling outage charge is anticipated, the business area will request a series of deferred work orders be issued. The set of deferred work orders will include one work order for each nuclear production FERC O&M account anticipated to be charged (the same FERC accounts used to record the refueling outage costs to expense). As costs are incurred during the outage, the FERC specific deferred work order will accumulate costs previously charged to the specific FERC O&M account. The use of work orders facilitates the accumulation of charges, but it also facilitates review for audit purposes.

Other Regulatory Assets

The accumulation of refueling outage costs for those jurisdictions allowing the deferral-and-amortization method will be cleared from the deferred work order to FERC Account 182.3, *Other Regulatory Assets*. The subsequent amortization of each balance reduces the regulatory asset to zero over the period the plant is operating until the next reload outage. The regulatory asset account will be maintained separate for each reload at each unit and also by each applicable nuclear production FERC O&M account. It is anticipated that this information will be segregated via a work order tag in the regulatory asset account.

Various Jurisdictions

For any rate jurisdiction that has not approved the use of the deferral-and-amortization method for nuclear refueling outage costs, that jurisdiction will continue to use the direct expensing method for its portion of the nuclear refueling outage costs. Therefore, unless all rate jurisdictions authorize use of the deferral-and-amortization method, the accounting will be maintained by rate jurisdiction.

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Assuming there are some rate jurisdictions that will allow the use of the deferral-and-amortization method and others that will not, the following steps generally will occur:

1. The nuclear plant personnel identify the refueling expenses that are appropriate to be deferred. Plant personnel do not allocate jurisdictional costs and thus gather total company charges only under this policy.
2. The plant personnel assign the identified costs in step 1 to a deferred work order, with each work order being specific to a FERC account and a particular reload.
3. The charges in the deferred work order are allocated to the various rate jurisdictions each month (based on the appropriate jurisdictional allocation factor in use at the time for each nuclear production FERC O&M account).
4. For those jurisdictions using the deferral-and-amortization method, the jurisdictional work order will set up the regulatory asset for amortization.
5. For those jurisdictions using the direct expense method, the costs in the jurisdictional work order are expensed in the month incurred.
6. The regulatory asset is maintained by each reload and by each applicable FERC O&M account such that the amortization is charged to the appropriate FERC O&M account each month

Amortization

The monthly amortization is calculated for each nuclear production FERC account for each reload for each unit separately. The amortization is a straight-line calculation derived by dividing the amount accumulated for the refueling outage by the number of months in the amortization period. The following method is used to calculate the amortization period.

Amortization Period
The amortization begins with the month the unit comes on-line, and continues through the month before it comes back on-line with the next refueled core. The intent behind using this period is to be assured that the previous deferral finishes the month prior to the next one beginning, leaving no months without an amortization or having amortizations from the previous and current reload overlapping. For example, the unit comes off line in February 2008 to refuel and comes back on-line March 2008. The plant operates through the rest of 2008, all of 2009, and comes off-line in February 2010 for the next refueling. This refueling is complete in March 2010. The amortization period is the number of months from March 2008 to February 2010, or 24 months in this example.

The number of months in the amortization is set based on the expected future refueling date for the next outage. The date, although a forecast, is a fairly certain date that will usually only fluctuate by one or two months on either side of the forecast date. When it is known that the next reload date has moved, the amortization period is adjusted. The amortization is adjusted for the remaining months by dividing the current balance by the remaining months in the amortization period. Continuing the

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

above example, if the refueling date is revised from February 2010 to April 2010 in January 2010, then the remaining amortization period is lengthened by two months. In January 2010, the remaining amortization was 2 months and is lengthened to 4 months based on the revised date for refueling.

FERC O&M Accounts

Based on accumulating the charges to a FERC specific deferred work order, the amortization is calculated for the month for each applicable O&M account. Each refueling operation may have a different spread of the costs incurred across the various nuclear O&M accounts; therefore, there may be many amortizations being calculated for each reload to effectively charge the correct FERC O&M account. The amortization is charged to the same nuclear production O&M expense account as would be used for direct expensing. The amortization period is the same across all FERC O&M account amortizations.

Applicable FERC O&M Accounts to Nuclear Refueling Outages

FERC Account	Account Title
Operations	
517	Operation Supervision and Engineering
519	Coolants and Water
520	Steam Expenses
523	Electric Expenses
524	Miscellaneous Nuclear Power Expenses
Maintenance	
528	Maintenance Supervision and Engineering
529	Maintenance of Structures
530	Maintenance of Reactor Plant Equipment
531	Maintenance of Electric Plant
532	Maintenance of Miscellaneous Nuclear Plant

Pick-ups

The term "pick-ups" is used to refer to the trailing costs that occur subsequent to the completion of the work. Business unit personnel are expected to book all known or estimable costs in the final month of the outage work. By recognizing an estimate of work completed to date, the amortization can begin with a very close approximation of total costs in the deferred work orders. The costs incurred in the "post-outage" phase are recognized in the deferred work orders with a debit offset by a credit to account payable or unvouchered liabilities. When the final costs are determined, the entire estimate is reversed with the actual payment being recognized to the appropriate deferred work order.

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There is a time limit on this process. Costs not finalized within three months after the unit begins operating are settled to expense.

Direct Expensing

Assuming a jurisdiction may not adopt this change of accounting for its customers, their portion of the O&M costs will be expensed when incurred. The jurisdictional split is determined at the time the set of FERC specific deferred work orders is requested for the outage. Every charge booked to the deferred work order will be allocated between jurisdictions that allowed the deferral-and-amortization method of accounting and those jurisdictions using the direct expense method. For example, if 75% of the jurisdictions allow deferred accounting and 25% do not, for every dollar incurred, 25 cents is expensed immediately and 75 cents is deferred and amortized. See steps defined under the "*Various Jurisdictions"* section above.

Tax Treatment

The treatment described to this point deals with the financial treatment of these costs for book purposes. The treatment of these costs for tax purposes is not impacted by whether the costs are deferred and amortized or expensed as incurred. The amount spent in a given year on refueling costs is what is deducted for income tax purposes. Therefore, choosing to defer some of the O&M costs for the books creates a timing difference between the book and tax recognition for these refueling costs. To recognize this difference, a deferred tax liability is created, setting up when the costs are expensed for taxes and flowing back when the amortization is complete.

Policy Application

Making the decision of where a particular cost should be charged may not always be clear and concise and interpretations will have to be made. Nuclear refueling costs meeting the above criteria for deferral can be charged to a deferred work order while all routine maintenance and standard operating costs should be charged to the appropriate O&M expense accounts. Any uncertainty about this policy should be directed to Regulatory Accounting for resolution.

Regulatory

Interchange Agreement

Costs incurred in the nuclear production O&M FERC accounts are shared between the two Northern State Power companies through the FERC jurisdictional "Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)" (Interchange Agreement). Costs are shared based on assignment to specific FERC accounts using a ratio of either the 36 month coincident peak demand or current year energy requirements. Through the Interchange Agreement, NSPM bills a proportionate share of the nuclear production O&M expense to NSPW. The use of the

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

deferral-and-amortization method of accounting for nuclear production O&M costs will change the pattern of expensing, however, the content of what is being expensed as well as the FERC accounts used to record those same expenses has not changed. Therefore, there is no impact to the Interchange Agreement resulting from this use of the deferral-and-amortization method.

Internal Controls

Regulatory Accounting has initiated the following tasks to assure that a valid work order for the regulatory assets resulting from this process exists from month to month:

- Working with the nuclear plant personnel to assure that proper documentation of cost assignment is being maintained;
- Periodically reviewing deferred work orders to assure that only proper costs are being included;
- Establishing the appropriate jurisdictional allocations for each deferred work order;
- Communicating this policy and its implications for the budgeting process for departmental operating expenses to all business unit personnel responsible for departmental budgets;
- Providing forecast information for the future amortizations applicable to this method based on the business area's budget of deferred costs.

Accountabilities

Business Unit Personnel

Business unit personnel are responsible for the following:

- Requesting set of deferred work orders prior to the first refueling outage charge;
- Making sure all costs are being appropriately tracked based on the rules stated above;
- Assuring unvouchered liabilities are booked timely;
- Providing all supporting documentation for the costs contained in any deferred work order;
- Keeping Regulatory Accounting aware of any changes to the refueling schedule in time to affect the monthly amortization.

Regulatory Accounting

Regulatory Accounting is responsible for the following:

Planned Major Maintenance – Nuclear Refueling Outage (Uniform Policy)

- Performing the compliance accounting associated with this deferral;
- Providing the appropriate jurisdictional allocators for the various accumulating work orders;
- Calculating and documenting the monthly amortization;
- Providing all relevant deferral related information for the amortization for the forecast and for rate case preparations;
- Periodically reviewing work orders for the appropriateness of charges and working with the business unit personnel to resolve any issues.

References

FASB Staff Position No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities*, September 2006

Supercedure

This is the first issuance of this policy.

Appendices

There are no appendices to this policy

Prairie Island Unit 1 - Fall 2018 Actual Outage Costs

Cost Description	Total Cost
[PROTECTED DATA BEGINS	[PROTECTED DATA BEGINS

Prairie Island Unit 1 - Fall 2018 Actual Outage Costs

Cost Description	Total Cost	
PROTECTED DATA ENDS]	**PROTECTED DATA ENDS]**	**$ 22,455,123**
Total Contractor		
Utility/Other Expense	$ 22,914	**$ 22,914**
Total Other		
Materials	$ 2,539,015	**$ 2,539,015**
Total Materials		
Employee Labor	$ 7,233,309	
T&D Labor	$ 505,366	**$ 7,738,676**
Total Labor		
Employee Expenses	$ 197,546	
Outage Employee Expenses from Other Sites	$ 280,792	**$ 478,337**
Total Empl/Oper		
		$ 33,234,065
GRAND TOTAL		

Prairie Island Nuclear Generating Plant
Outage Labor Costs - Unit 1 Refueling Outage 31 (1R31) - Fall 2018 Actual

HCC	HCCDesc	Res3	Total
100653	**PI Site Management**	Overtime	$ 86,956
		Premium	256
100654	**PI Employee Concerns Prog**	Overtime	5,518
100656	**PI Quality Control**	Overtime	28,354
		Premium	15,313
100657	**PI Perform Improvement**	Overtime	(6,696)
100659	**PI Chemistry**	Overtime	32,113
		Premium	9,049
100660	**PI Chemistry Tech Sup**	Overtime	94,658
		Premium	41,333
100661	**PI Chemistry Operations**	Overtime	218,221
		Premium	118,179
100666	**PI Maintenance Support**	Overtime	70,282
		Premium	199
100669	**PI Planning**	Overtime	251,484
100670	**PI Radiation Protection**	Overtime	187,859
		Premium	62,271
100671	**PI Raditaion Protection Support**	Overtime	133,369
		Premium	51,898
100672	**PI Radiation Protect Operations**	Overtime	398,853
		Premium	201,297
100676	**PI Operations Support**	Overtime	159,645
		Premium	33,114
100677	**PI Work Control Center**	Overtime	54,124
		Premium	1,374
100679	**PI Outage**	Overtime	50,415
100680	**PI Scheduling**	Overtime	41,903
100684	**PI Training Operations**	Overtime	68,191
100685	**PI Training Technical**	Overtime	35,887
100686	**PI Training Maintenance**	Overtime	14,482
100687	**PI Training Simulator**	Overtime	6,537
100688	**PI Training Support**	Overtime	6,812
100689	**PI Licensing**	Overtime	1,133
100692	**PI Eng FIN Mechanical**	Overtime	20,981
100695	**PI Engineering Systems**	Overtime	87,250
100697	**PI Eng Systems Electric I and C**	Overtime	6,510
100698	**PI Eng Systems BOP**	Overtime	11,723
100699	**PI Eng Support**	Overtime	12,240
100701	**PI Engineering Programs**	Overtime	173,923
100702	**PI Eng Prog-LT Term Prog**	Overtime	5,115

100703	**PI Eng Prog - Equip Rel P**	Overtime	23,233
100705	**PI Engineering Design**	Overtime	42,622
100707	**PI Eng FIN Electrical**	Overtime	53,870
100709	**PI Eng Design Support**	Overtime	239
100711	**PI Doc Control and Procedures**	Overtime	17,448
		Premium	3,437
100713	**PI Administration Services**	Overtime	88,011
		Premium	22,419
100715	**PI Emergency Planning**	Overtime	10,994
100717	**PI Security**	Overtime	21,436
		Premium	3,171
102799	**PI Shift Operations- Bargaining**	Overtime	766,962
		Premium	635,410
102800	**PI Maint-Instr&Cntrl - Bargaining**	Overtime	598,067
		Premium	184,234
102801	**PI Maint-Electrical - Bargaining**	Overtime	477,727
		Premium	145,684
102802	**PI Maint-Mechanical - Bargaining**	Overtime	710,696
		Premium	264,426
102803	**PI Maint-Facilities - Bargaining**	Overtime	513,994
		Premium	23,748
102923	**PI Maint-Craft Aug**	Overtime	3,575
102924	**PI Maint-Electrical**	Overtime	458,216
		Premium	44,042
102925	**PI Maint-Instr&Cntrl**	Overtime	(210,492)
		Premium	5,179
102926	**PI Maint-Mechanical**	Overtime	(74,756)
		Premium	90,179
102927	**PI Maint-Facilities**	Overtime	8,431
102928	**PI Shift Operations**	Overtime	109,030
		Premium	(132,773)
300837	**PI Information Technology**	Overtime	25,894
300898	**PI Rad Prot - Radwaste**	Overtime	12,200
Grand Total			**$ 7,738,676**

Monticello Planned Refueling Outage (RFO 29) - Spring 2019
Actual Costs Through August, 2019

	Years 2018-2019
Contract Services	
[PROTECTED DATA BEGINS	[PROTECTED DATA BEGINS
PROTECTED DATA ENDS]	PROTECTED DATA ENDS]
Total Contract Services	**$ 23,470,178**
Employee Expenses	
Mileage, Per Diem and Other	548,893
Total Employee Expenses	**$ 548,893**
Labor	
Base Labor, Overtime and Travelers	6,230,786
Total Labor	**$ 6,230,786**

Monticello Planned Refueling Outage (RFO 29) - Spring 2019
Actual Costs Through August, 2019

Materials		
Base Outage Materials		2,315,058
Total Materials	**$**	**2,315,058**
Utility/Other Expenses		
Equipment Rental and Other		181,655
Total Utility/Other Expenses	**$**	**181,655**
Grand Total - Actual Through August 2019	**$**	**32,746,570**
Outage Costs Amortized into 2020-2022 per Rate Case - July 2019 Forecast		**33,400,000**

Monticello Nuclear Generating Plant
Outage Labor Costs - Refueling Outage 29 - 2019 Actual

Cost Center No. & Description	Labor Object Description		Labor $
100607 MT Site Management	Base Labor	$	6,391
100608 MT Employee Concerns Prog	Overtime		1,799
100610 MT Quality Control	Overtime		43,871
100610 MT Quality Control	Premium Time		13,737
100611 MT Perform Improvement	Overtime		5,613
100612 MT Plant Management	Overtime		6,255
100612 MT Plant Management	Premium Time		477
100613 MT Chemistry	Overtime		121,413
100613 MT Chemistry	Premium Time		69,272
100617 MT Maintenance Support	Overtime		178,016
100620 MT Radiation Protection	Overtime		310,162
100620 MT Radiation Protection	Premium Time		164,364
100623 MT Outage	Base Labor		12
100623 MT Outage	Overtime		23,618
100623 MT Outage	Premium Time		415
100624 MT Scheduling	Overtime		82,196
100627 MT Training Operations	Base Labor		380
100627 MT Training Operations	Overtime		51,304
100629 MT Training Maintenance	Overtime		22,589
100631 MT Training Support	Overtime		11,203
100633 MT Engineering Systems	Base Labor		162
100633 MT Engineering Systems	Overtime		111,328
100633 MT Engineering Systems	Premium Time		253
100637 MT Engineering Programs	Overtime		106,181
100639 MT Engineering Design	Overtime		71,883
100643 MT Doc Control and Procedures	Overtime		367
100645 MT Administration Svcs	Overtime		58,881
100645 MT Administration Svcs	Premium Time		15,812
100649 MT Security	Base Labor		990
100649 MT Security	Overtime		17,662
100649 MT Security	Premium Time		3,215
102759 MT Maint-Craft Aug - Bargaining	Base Labor		4,152
102759 MT Maint-Craft Aug - Bargaining	Other Compensation		87,823
102759 MT Maint-Craft Aug - Bargaining	Overtime		97,701
102759 MT Maint-Craft Aug - Bargaining	Premium Time		6,984
102763 MT Training-Simulator - Bargaining	Base Labor		86
102763 MT Training-Simulator - Bargaining	Overtime		2,421
102804 MT Shift Operations - Bargaining	Base Labor		5,661
102804 MT Shift Operations - Bargaining	Overtime		702,009
102804 MT Shift Operations - Bargaining	Premium Time		464,431
102805 MT Maintenance I&C - Bargaining	Base Labor		1,924
102805 MT Maintenance I&C - Bargaining	Overtime		145,510
102805 MT Maintenance I&C - Bargaining	Premium Time		95,512

102806 MT Maintenance Electrical - Bargaining	Base Labor		1,387
102806 MT Maintenance Electrical - Bargaining	Overtime		85,246
102806 MT Maintenance Electrical - Bargaining	Premium Time		46,707
102807 MT Maint-Mechanical - Bargaining	Base Labor		9,982
102807 MT Maint-Mechanical - Bargaining	Overtime		283,697
102807 MT Maint-Mechanical - Bargaining	Premium Time		180,143
102808 MT Maintenance Fac - Bargaining	Base Labor		825
102808 MT Maintenance Fac - Bargaining	Overtime		77,226
102808 MT Maintenance Fac - Bargaining	Premium Time		39,707
102916 MT Maintenance Electrical	Base Labor		278,697
102916 MT Maintenance Electrical	Other Compensation		8,395
102916 MT Maintenance Electrical	Overtime		311,537
102916 MT Maintenance Electrical	Premium Time		49,114
102917 MT Maintenance Fac	Overtime		10,363
102918 MT Maintenance I&C	Overtime		9,095
102918 MT Maintenance I&C	Premium Time		14,436
102919 MT NGS Construction	Base Labor		793
102919 MT NGS Construction	Other Compensation		591
102919 MT NGS Construction	Overtime		15,356
102919 MT NGS Construction	Premium Time		3,174
102920 MT Shift Operations	Overtime		265,893
102920 MT Shift Operations	Premium Time		2,951
102921 MT Maint-Mechanical	Overtime		40,984
102921 MT Maint-Mechanical	Premium Time		4,451
102922 MT Training-Simulator	Overtime		7,357
103068 MT E Fix It Now FIN Electrical	Overtime		71,492
103069 MT E Fix It Now FIN Mechanical	Overtime		43,866
103078 Monticello Component Maintenance	Overtime		13,383
300834 MT Business Support-Final	Overtime		993
300834 MT Business Support-Final	Premium Time		251
	Subtotal Total 2019 Labor $'s	**$**	**4,992,127**
	2018 Labor for Refueling Outage 29		51,851
	Total 2018 & 2019 Labor $'s	**$**	**5,043,978**
	Labor for Travelers		1,186,808
	Total RFO29 Labor	**$**	**6,230,786**

Prairie Island Unit 2 - Fall 2019 Outage Budget

Cost Description	Total Cost
[PROTECTED DATA BEGINS	[PROTECTED DATA BEGINS
CONTRACTORS	

Prairie Island Unit 2 - Fall 2019 Outage Budget

Cost Description	Total Cost
PROTECTED DATA ENDS]	PROTECTED DATA ENDS]
GRAND TOTAL	**$ 32,000,000**

Prairie Island Nuclear Generating Plant

Outage Labor Costs - Unit 2 Refueling Outage 31 (2R31) - Fall 2019

Cost Center	CC Desc	Contractor_Name	Total
			[PROTECTED DATA BEGINS
100653	PI Site Management	Xcel-Labor Overtime	$
100654	PI Employee Concerns Prog	Xcel-Labor Overtime	
100656	PI Quality Control	Xcel-Labor Overtime	
100657	PI Perform Improvement	Xcel-Labor Overtime	
100658	PI Plant Management	Xcel-Labor Overtime	
100659	PI Chemistry	Xcel-Labor Overtime	
100660	PI Chemistry Tech Sup	Xcel-Labor Overtime	
100661	PI Chemistry Operations	Xcel-Labor Overtime	
100666	PI Maintenance Support	Xcel-Labor Overtime	
100669	PI Planning	Xcel-Labor Overtime	
100670	PI Radiation Protection	Xcel-Labor Overtime	
100671	PI Raditaion Protection Support	Xcel-Labor Overtime	
100672	PI Radiation Protect Operations	Xcel-Labor Overtime	
100676	PI Operations Support	Xcel-Labor Overtime	
100677	PI Work Control Center	Xcel-Labor Overtime	
100678	PI Safety and Health	Xcel-Labor Overtime	
100679	PI Outage	Xcel-Labor Overtime	
100680	PI Scheduling	Xcel-Labor Overtime	
100684	PI Training Operations	Xcel-Labor Overtime	
100685	PI Training Technical	Xcel-Labor Overtime	
100686	PI Training Maintenance	Xcel-Labor Overtime	
100687	PI Training Simulator	Xcel-Labor Overtime	
100688	PI Training Support	Xcel-Labor Overtime	
100689	PI Licensing	Xcel-Labor Overtime	
100692	PI Eng FIN Mechanical	Xcel-Labor Overtime	
100695	PI Engineering Systems	Xcel-Labor Overtime	
100701	PI Engineering Programs	Xcel-Labor Overtime	
100705	PI Engineering Design	Xcel-Labor Overtime	
100707	PI Eng FIN Electrical	Xcel-Labor Overtime	
100711	PI Doc Control and Procedures	Xcel-Labor Overtime	
100713	PI Administration Services	Xcel-Labor Overtime	
100715	PI Emergency Planning	Xcel-Labor Overtime	
100717	PI Security	Xcel-Labor Overtime	
102799	PI Shift Operations- Bargaining	Xcel-Labor Overtime	
102800	PI Maint-Instr&Cntrl - Bargaining	Xcel-Labor Overtime	
102801	PI Maint-Electrical - Bargaining	Xcel-Labor Overtime	
102802	PI Maint-Mechanical - Bargaining	Xcel-Labor Overtime	
102803	PI Maint-Facilities - Bargaining	Xcel-Labor Overtime	
102924	PI Maint-Electrical	Xcel-Labor Non-Fiori Travelers	
		Xcel-Labor Overtime	

		Xcel-Transmission & Distribution (T&D)
102925	**PI Maint-Instr&Cntrl**	Xcel-Labor Non-Fiori Travelers
		Xcel-Labor Overtime
102926	**PI Maint-Mechanical**	Xcel-Labor Non-Fiori Travelers
		Xcel-Labor Overtime
		Xcel-Transmission & Distribution (T&D)
102927	**PI Maint-Facilities**	Xcel-Labor Overtime
102928	**PI Shift Operations**	Xcel-Labor Overtime
103081	**Maint - FIN**	Xcel-Labor Overtime
103082	**Component Maintenance**	Xcel-Labor Overtime
Grand Total		

PROTECTED DATA ENDS]

Prairie Island Unit 1 - Fall 2020 Outage Budget

Cost Description	Total Cost
[PROTECTED DATA BEGINS	[PROTECTED DATA BEGINS
CONTRACTORS	

Prairie Island Unit 1 - Fall 2020 Outage Budget

Cost Description	Total Cost
PROTECTED DATA ENDS]	PROTECTED DATA ENDS]
GRAND TOTAL	**$ 32,000,000**

NRC Oversight and Performance Ratings

NRC Reactor Oversight Process (ROP) and Action Matrix

The NRC has instituted a Reactor Oversight Process (ROP) to evaluate the safety and security performance of the nuclear power reactors in the U.S.[1] The NRC's ROP uses seven "cornerstones" to describe the essential features of its strategic performance areas: reactor safety, radiation protection, and security[2]. Performance in these cornerstones is assessed on a quarterly basis using nearly 20 discrete performance indicators reported by the reactor owners, supplemented by findings from NRC inspections. The link between the assessment component of the ROP and mandated NRC responses is called the Action Matrix.

The Action Matrix features five columns of performance, as rated by the NRC:

- **Column I** - When the performance indicators and inspection findings all fall in expected ranges, a reactor is placed in Column I, or "Licensee Response," reflecting the fact that the licensee takes responsibility for addressing these minor problems and the NRC continues with its normal inspections.
- **Column II** - If performance in a cornerstone drops a little below expectations, the reactor moves into Column II "Regulatory Response," reflecting the fact that the NRC now responds by increasing inspections.
- **Column III** - If performance drops further in a cornerstone or declining performance is detected in another cornerstone, a reactor moves into Column III, "Degraded Cornerstone," where the ROP mandates additional NRC inspections.
- **Column IV** - If declining performance deepens and/or broadens, a reactor moves into Column IV, "Multiple/Degraded Cornerstone," where the NRC takes further action.
- **Column V** - If performance problems reach epidemic proportions, a reactor enters Column V, "Unacceptable Performance," and is shut down by the NRC.

[1] The NRC has summarized its *Reactor Oversight Process* in a diagram included as Attachment A.

[2] The NRC's cornerstones are listed on Attachment B, the NRC's *Reactor Oversight Framework*.

NRC Ratings for Inspection Findings and Performance Reviews

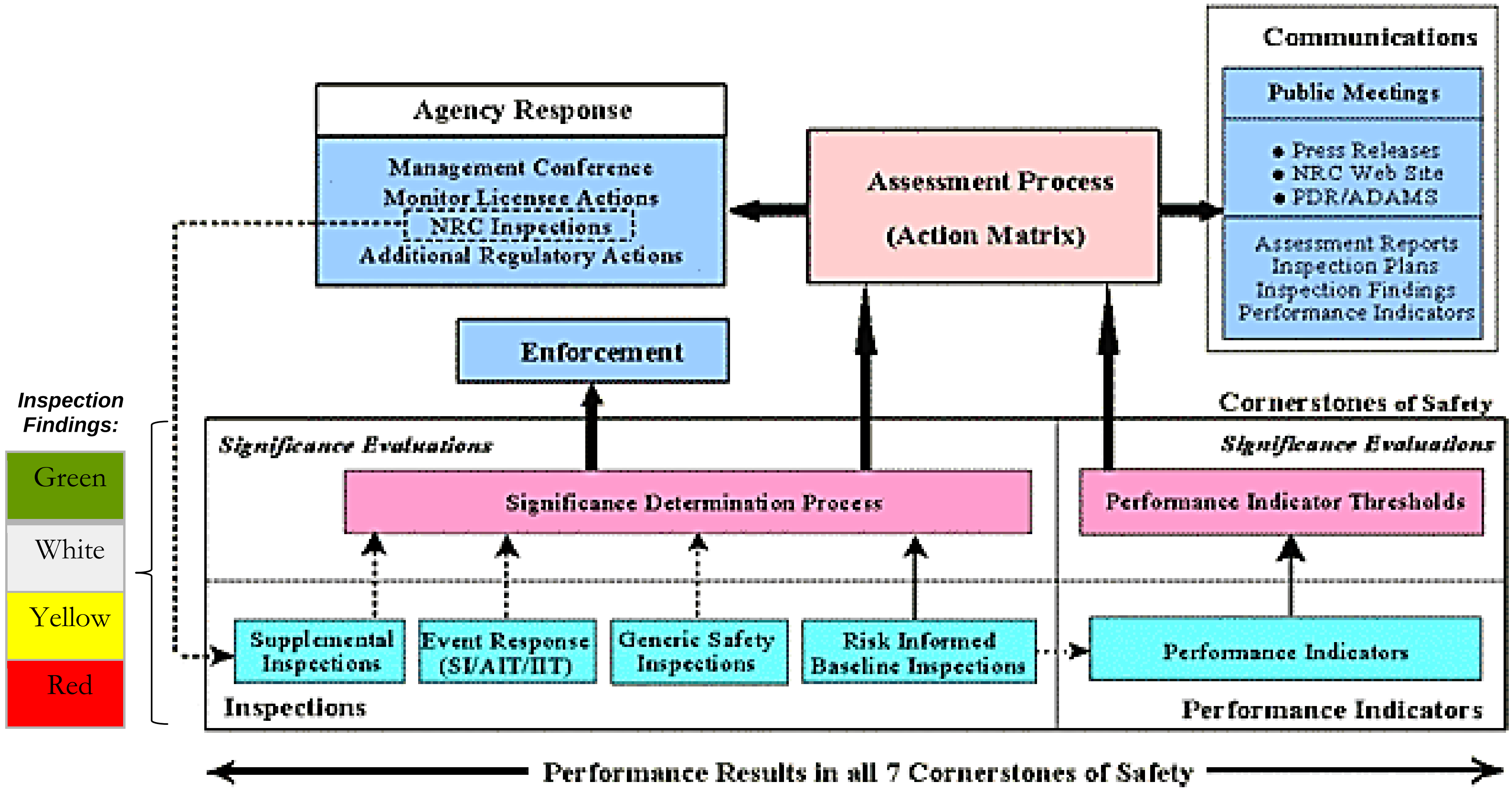
The NRC uses a color-coding scheme to rank the level of concern for issues it identifies for nuclear operators, either through inspections or through review of quarterly performance reporting. These rankings range as follows:

- **Green** - lowest level of concern
- **White** – second lowest level of concern
- **Yellow** – second highest level of concern
- **Red** - highest level of concern

The number and severity of issues identified for a plant unit at a point in time determine its Column rating under the ROP Action Matrix. For example, if only green (lowest level) issues are outstanding, the unit remains at Column I. If a single white finding/issue is outstanding, the unit is moved to Column II and requires more NRC oversight and inspections until the issue is considered resolved, or "closed". If multiple white findings, or a single yellow finding, is outstanding, the unit is moved to Column III, with more oversight and inspections, and so on.

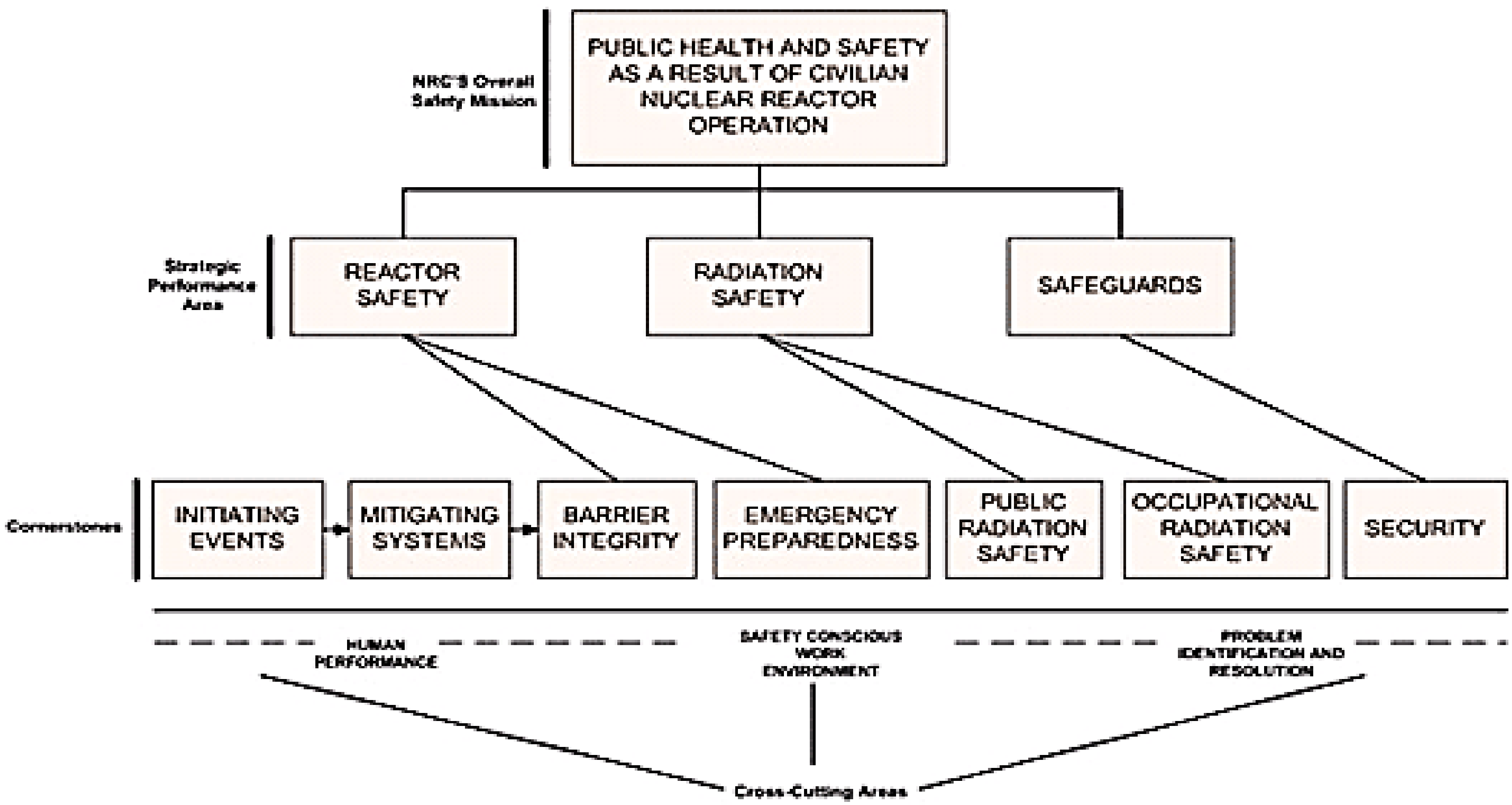
The column status of a nuclear unit remains in place for each calendar quarter, and is only moved upward (i.e. from II to I) at the beginning of the next quarter after an outstanding issue is closed by the NRC. Column status can move downward (e.g. from I to II) immediately when an issue is officially determined by the NRC to be outstanding. The NRC has an appeals and review process for operators to challenge a proposed inspection or performance review finding, including conferences, public hearings and other procedures. The NRC does not announce the official change in column status for a unit until after this process concludes.

NRC's
REACTOR OVERSIGHT PROCESS



NRC's

REGULATORY FRAMEWORK



Responses to Table 7		
Project/ Compliance Requirement	**Code, Regulation, Document or Finding Requirement**	**Discussion**
License Renewal	NRC License Requirements and Commitments from Licensce Extension LAR (License Ammendment)	The projects included in the License Renewal Grouping were performed as part of commitments and license requirements that came out of the NRC License Ammendment process for extending our operating Licenses to 2033 and 2034. These projects would not have been performed had the Company not extended its operating licenses. Additionally, these projects had not been identified at the time of our 2008 Certificate of Need because we sought that Certificate from the Commission before completing the License Amdndment process at the NRC.
Fire Protection (NFPA 805 Projects)	Compliance with NFPA 805 or 10CFR50 Appendix R	NRC required compliance with 10 C.F.R. 50 Appendix R (Deterministic Approach to Fire Protection Requirments) or, as an alternative, required a license ammendment to adopt NFPA 805: Performance-Based Standard for Fire Protection for Light Water Reactor Electic Generating Plants (Risk Based Approach using PRA). For Prairie Island, it was determined to be more cost effective to ammend our license to adopt NFPA 805 as discussed in the 2015 Rate Case. The projects included in this category were projects related to the NFPA 805 License Ammendment, the PRA models required for compliance, and plant modifications that were a condition of our license ammendment.
External Events - Fukushima Requirements	NRC 2011 an other Orders Surrounding the US Response to Fukushima	The projects included in this category were all driven by the requirements set forth in the NRC orders related to the Fukushima event. These projects would not have been completed but for those NRC orders.
RCP Seal Re-Design	Compliance with NFPA 805 License Requirements	This project was required as part of commitments made as part of the NFPA 805 Licensing Ammendment. The project would not have been completed but for that Licensing Amendment.
Physical Protection and Plant Security	NRC 10CFR 73 Requirements	Projects in this category were required to be implemented to comply with requirements of 10 C.F.R. 73. These projects would not have been completed but for those requirements.
Security-Force on Force	NRC Security Inspections	This project was required to comply with NRC regulations 10 C.F.R. 73 and additional related orders and regulations put forth by the NRC. This project was to perform modifications and updates to the site's Security Strategy to ensure compliance which would be evaluated through NRC Force-on-Force Exercises. These projects would not have been completed but for those requirements.
Steam Generator Narrow Range Level Instrumentation	Requirements for instrument qualification to Reg Guide 1.97 as part of Alternate Source Term License Ammendment	This project replaced Narrow Range Level Indication Instrumentation to comply with Regulatory Guide 1.97 requirements. Compliance with Reg Guide 1.97 was required for these instruments based on our Alternate Source Term License Ammendment. These projects would not have been completed but for those requirements.

Cyber Security	NRC 10 CFR 73.74 Requirements	The projects included in the category were all driven by changes to 10 CFR 73.74 requirements and conditions of our license ammendment for the cyber secuirity program. These projects would not have been completed but for those requirements.
Emergency Requirements - Security & Diesel Backup	NRC B.5.b Regulations	The projects included in this category were required to address new regulations related to Station Blackout and Advanced Accident Mitigation (B.5.b Requirements) for developing flexible and deployable strategies providing alternate means for accomplishing key safety functions following an accident. These projects would not have been completed but for those requirements.
Spent Fuel Pool Protection	NRC Finding	This project was required to resolve an NRC License Violation with regards to protecting the Component Cooling System from the impact of a design basis tornado missile. This projects would not have been completed but for that NRC requirement.
Gas Venting	NRC Generic Letter 2008-01	The projects in this category were required to meet new NRC requirements associated with Generic Letter 2008-01: Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems. These projects would not have been completed but for those requirements.
Battery Chargers	NRC Inspection Finding	This project was required to resolve an NRC Violation related to a susceptability of battery charger to locking up due to low input voltage during certain accident scenarios. This project would not have been completed but for those NRC requirements.
4KV Bus Modifications	NRC Commitment made in 2/3/14 response to NRC Request for Additional Information	This project was required to address NRC requirements resulting from the Open Phase Event at the Byron Nuclear Plant which impacted emergency electrical buses. This project would not have been completed but for those NRC requirements.
Diesel Room Venting	NRC Inspection Finding	This project was slated to resolve a non-conforming NRC licensing condition. Through further analysis, a simpler, alterantive solution was completed to resolve the issue. The alternative solution did not meet the threshold for being a capital project.
Diesel Transient	NRC requirement as part of License Ammendment related to the Battery Charger NRC Finding	This project was required as part of Licensing Conditions as part of a License Ammendment on Diesel Generator Volatage Requirements related to the Battery Charger NRC Finding. This project would not have been completed but for those NRC Licensing Conditions.
Emergency Siren Narrowband	FCC Requirement - compliance requirement of December 2012	This project was required to comply with an FCC mandate to change commercial radios with specific VHF and UHF bands to allow for additional FCC channels (narrowbanding) by December 2012. This project would not have been completed but for that FCC mandate.

Responses to Table 8		
Project/ Compliance Requirement	**Code, Regulation, Document or Finding Requirement**	**Discussion**
Fire Protection	Compliance with NFPA 805 or 10CFR50 Appendix R	NRC required compliance with 10 C.F.R. 50 Appendix R (Deterministic Approach to Fire Protection Requirments) or, as an alternative, required a license ammendment to adopt NFPA 805: Performance-Based Standard for Fire Protection for Light Water Reactor Electic Generating Plants (Risk Based Approach using PRA). For Prairie Island, it was determined to be more cost effective to ammend our license to adopt NFPA 805 as discussed in the 2015 Rate Case. The projects included in this category were projects related to the NFPA 805 License Ammendment, the PRA models required for compliance, and plant modifications that were a condition of our license ammendment.
External Events - Fukushima	NRC 2011 an other Orders Surrounding the US Response to Fukushima	The projects included in this category were all driven by the requirements set forth in the NRC orders related to the Fukushima event. These projects would not have been completed but for those NRC orders.
Security Upgrades	NRC 10CFR 73 Requirements	This project was cancelled as other non-capital project approaches were persued to ensure compliance.
Tornado Missile/ Projectile Protection	NRC RIS 2015-06	This project was required based on a draft version of NRC RIS 2015-06 which would have required us to implement modifications to comply with the RIS. The final version of the RIS did not require modifications to ensure compliance for Prairie Island, and this Project was cancelled.
4.16 KV Bus Modificaitons	NRC Commitment made in 2/3/14 response to NRC Request for Additional Information	This project was required to address NRC requirements resulting from the Open Phase Event at the Byron Nuclear Plant which impacted emergency electrical buses. These projects would not have been completed but for those requirements.
Steam Generator Water Level	Requirements for instrument qualification to Reg Guide 1.97 as part of Alternate Source Term License Ammendment	This project replaced Narrow Range Level Indication Instrumentation to comply with Regulatory Guide 1.97 requirements. Compliance with Reg Guide 1.97 was required for these instruments based on our Alternate Source Term License Ammendment. This project would not have been completed but for those requirements.