Direct Testimony and Schedules
Timothy J. O'Connor

Before the Minnesota Public Utilities Commission
State of North Dakota

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

Case No. PU-12-____
Exhibit___(TJO-1)

Nuclear Operations

December 18, 2012

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Timothy J. O'Connor. I am the acting Chief Nuclear Officer for Northern States Power Company (Xcel Energy or Company). I am responsible for all nuclear activities at the Monticello and Prairie Island plants.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 30 years 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 education and experience are detailed in Exhibit___(TJO-1), Schedule 1.

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

A. The purpose of my testimony is to present and support the Company's 2013 capital and O&M nuclear budgets. My testimony highlights that:

- We continue to implement extensive capital and O&M investments in our nuclear plants which is necessary to maintain these safe, reliable, and carbon-free facilities;
- We have taken steps to control expenses; and
- The nuclear industry is facing significant future challenges in terms of labor and increasing compliance requirements.

II. KEY NUCLEAR FUNCTIONS AND ACTIVITIES

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 585-megawatt boiling water reactor and was originally licensed by the Nuclear Regulatory Commission ("NRC") in 1970. The initial license was scheduled to expire in 2010. In 2006, the NRC approved a renewed license for Monticello, extending its operating life until 2030. In September 2006, the Minnesota Public Utilities Commission (MPUC) approved the use of dry spent-fuel storage at Monticello to provide the spent-fuel storage capacity to operate until 2030. Additionally, in January 2009, the MPUC approved Xcel Energy's application to implement an extended power uprate at the plant.

Prairie Island is a two-unit pressurized water reactor, with each unit rated at 550 MW. 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, respectively. In December 2009, the MPUC approved the expanded use of dry spent-fuel storage at Prairie Island to provide the spent-fuel storage capacity to operate until 2033/34. Additionally, in December 2009, the MPUC approved our application to implement an extended power uprate at the plant.

Monticello and Prairie Island continue to be two of Xcel Energy's most reliable baseload electric generation assets, providing approximately 29 percent of the electricity to NSP's system. These plants are part of a diverse operating

portfolio that provides a hedge against changes in resource availability, fossil fuel prices and future emissions regulations. Additional details regarding the scope of the Company's nuclear operations are outlined in Exhibit___(TJO-1), Schedule 2.

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

A. Our top priorities are continued safe and reliable operation of our nuclear facilities. Over the course of 2013, we will be making significant investments in capital projects to replace and upgrade existing equipment and systems to support continued operations and power uprate and will continue with extensive O&M work to ensure these plants operate safely and reliably.

Another top priority relates to recent events. As the Commission is well aware, the disaster at the Fukushima Daiichi plant in Japan occurred in March 2011. Since that disaster occurred, the NRC has been engaged in an extensive review of current operating conditions and guidelines for our nation's nuclear facilities. We expect to continue these efforts throughout 2013 and beyond.

Q. WHAT ARE THE PRIMARY CHALLENGES YOU ARE FACING IN NUCLEAR OPERATIONS?

A. Compliance with new regulatory requirements will continue to be an issue for the next several years as more formal guidance is issued as a result of the NRC's Fukushima review. What was standard operating procedure in years past is no longer, and we are working to ensure continued compliance with new requirements. In addition, as discussed in Section VI of my testimony, competition for the highly skilled labor resources to staff our facilities and perform the necessary work will continue to be a challenge.

Q. PLEASE DESCRIBE THE BENEFITS OF THE COMPANY'S INVESTMENTS IN ITS NUCLEAR OPERATIONS.

A. The investments we are making not only support continued operation of the plants for the additional 20 years of plant life, but also provide improved safety margins and improved reliability.

For example, investments in the Monticello Life Cycle Management and Extended Power Uprate (LCM/EPU) project improve off-site, power and stability of power to the plant, which increases safety and reliability of the plant for production. These improvements also utilize updated technology not available when the plants went into service, further enhancing our operating characteristics for our employees and our communities.

III. SUMMARY OF REQUEST

Q. PLEASE PROVIDE A SUMMARY OF THE COSTS INCLUDED IN THE TEST YEAR.

A. Our 2013 budget includes $438 million in capital costs, as shown in Table 1 below.[1] These costs are primarily related to those investments necessary to support 20 years of additional operation under the renewed operating licenses at Monticello and Prairie Island and for the extended power uprate at Monticello.

[1] All cost figures identified in my testimony are provided on a total NSP-Minnesota company basis. The North Dakota-only jurisdictional allocation is reflected in the revenue requirement as provided in the Direct Testimony of Company witness Ms. Anne E. Heuer.

Table 1 - Test Year Capital Costs

	Prairie Island ($M)	Monticello ($M)
Strategic major projects	$ 242	$ 72
Dry cask storage	24	20
Mandatory compliance	23	6
Equipment reliability & improvements	20	25
Facilities	2	4
Total 2013 capital expenditure budget	**$ 311**	**$ 127**

Capital expenditures in Table 1 exclude the investment in nuclear fuel, which is also capitalized upon purchase and then amortized as consumed in plant operations. The 2013 test year includes capitalized fuel purchases of approximately $94 million and amortization of about $119 million for fuel consumed.

Many of our capital intensive projects have been underway prior to the test year. Although the capital expenditure budget for 2013 is $438 million (excluding nuclear fuel), total capital additions for nuclear facilities in-service since our 2011 test year are approximately $800 million, including approximately $67.6 million of capital projects in-service in 2010 and 2011 not included in that 2011 test year, $32.9 million in-service in 2012, and $699.5 million in-service in 2013.

In addition, our test year includes $326.9 million in O&M costs ($252.4 million for non-outage and $74.5 million for outages). As evidenced by the Table 2, the majority of these costs are divided among our need for labor to support plant activities to meet current and new regulatory requirements,

nuclear fees paid to government agencies and nuclear industry organizations, and outage costs.

Table 2 - Nuclear O&M Costs

	Test Year Budgeted Costs[2] ($M)
Non-Outage O&M Costs	
Labor	$ 131.6
Nuclear Related Fees	34.8
Contractors & Consultants	32.0
Security	27.2
Materials	16.8
Employee Expenses	4.2
Other	5.8
Total Non-Outage O&M	*$ 252.4*
	Test Year Budgeted Costs[3] ($M)
Outage O&M Costs	
Total Nuclear Outage Costs for Year (Spend)	$ 91.9
Deferral of Current Year Outage Costs	(91.9)
Outage Amortization	74.5
Net Outage-Related Nuclear Costs for Year	*$ 74.5*
Total 2013 Nuclear O&M Costs	**$ 326.9**

[2] Includes post-budget adjustments of $11 million as summarized on Schedule 6.
[3] Includes post-budget adjustments of $2 million as summarized on Schedule 6.

IV. COST CONTROLS

Q. PLEASE DESCRIBE THE COMPANY'S EFFORTS TO CONTROL COSTS.

A. The Company has taken a variety of steps in its efforts to control costs. For example, we implemented new management oversight processes over capital projects. During implementation of the LCM/EPU project at Monticello, we identified the need for a significant expansion in the scope of work being done. As a result of that expansion in work, we implemented a new management oversight process specific to that project. We initiated weekly meetings that included our Chief Executive Officer of NSP-Minnesota, Chief Financial Officer, General Counsel, and Controller. We also established two new financial management positions, Nuclear Controller and Vice President-Nuclear Finance, to provide additional oversight over nuclear costs. The oversight has added benefits to the management of all nuclear project work in general.

Q. HAS THE COMPANY INITIATED ANY OTHER COST CONTROL PROGRAMS?

A. Yes. We take the necessary steps to competitively source our major contract requirements. Where possible, we attempt to enter into fixed-price contracts, limiting our exposure to uncertain future inflationary pressures and unknown risks.

In addition, we seek to take advantage of economies of scale. For example, Xcel Energy works with owners of other nuclear facilities to share the costs of resolving common issues. The Company is currently a member of several industry groups, where we work with our industry partners to proactively identify potential issues, investigate whether our facilities may experience

similar issues, and identify how to most cost-effectively and efficiently improve plant operations. By being proactive and working with our industry partners, we are able to seek competitive bids for resources and materials, make purchases in advance, enhance cost savings, and balance in-house and external expertise to further control costs.

Q. PLEASE EXPLAIN THE WORK DONE WITH OTHER LICENSEES TO KEEP COSTS LOW.

A. We work collaboratively with our industry partners to take advantage of economies of scale and knowledge of industry trends to keep costs low. An example of this effort is our participation in USA Alliance, a conglomeration of 10 nuclear plants that purchase materials and equipment on a consolidated basis, allowing the partners to realize savings not available if such purchases were made on an individual basis. The Alliance provides a yearly estimate of savings achieved through participation. The Alliance estimated savings of $1.3 million to Xcel Energy in 2010 and $2.6 million in 2011. We expect similar savings to continue through 2012 and 2013.

Q. ARE THERE ANY OTHER INITIATIVES THE COMPANY HAS TAKEN THAT HAVE RESULTED IN SAVINGS?

A. In 2012, we constructed a new warehouse facility outside of the Prairie Island plant boundaries. This allows for delivery of equipment and supplies to be made at a point not requiring immediate security clearance. This saves labor resources because the deliveries do not require an extensive security process on a real-time basis. This also results in increased safety for our plant by minimizing the number of non-employees and non-contractors allowed access to the plant site.

Q. EVEN WITH THE COST INCREASES PROJECTED IN THE TEST YEAR, ARE THE COSTS OF OPERATING THE COMPANY'S NUCLEAR PLANTS STILL REASONABLE?

A. Yes. Our plants remain comparable to other operating units in the nation. We have attempted to evaluate our proposed budgets with our best estimate of industry costs in the test year. Applying a conservative annual escalation factor of 3.0 percent per year to 2011 Electric Utilities Cost Group (EUCG) U.S. nuclear plant cost data, we compared the test year operating budgets for Monticello and Prairie Island with the remainder of the industry (see Figures 1 and 2 below). This comparative data continues to show that Monticello and Prairie Island are operating at a reasonable cost.

Figure 1 - 2013 Single Unit Operating Costs

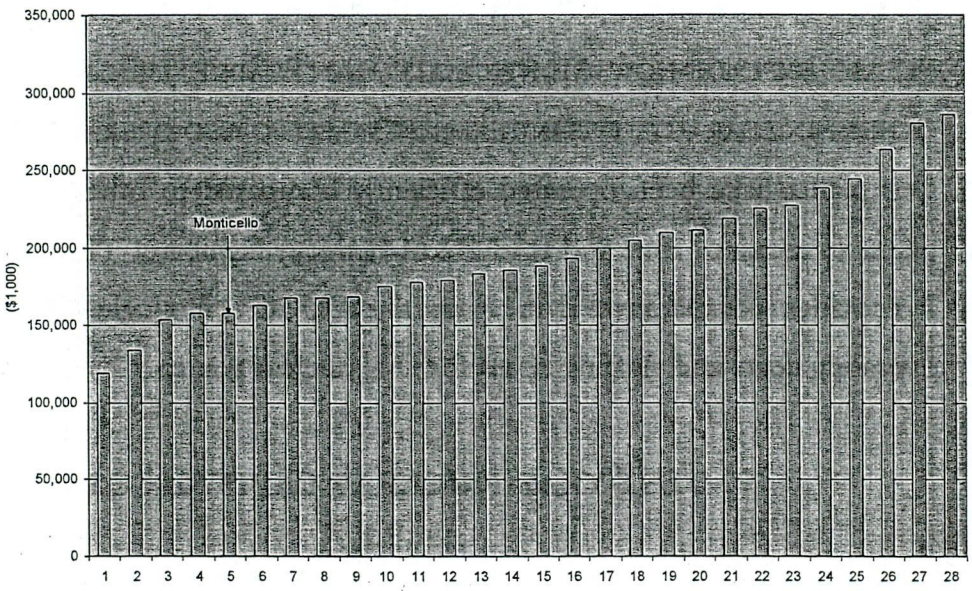
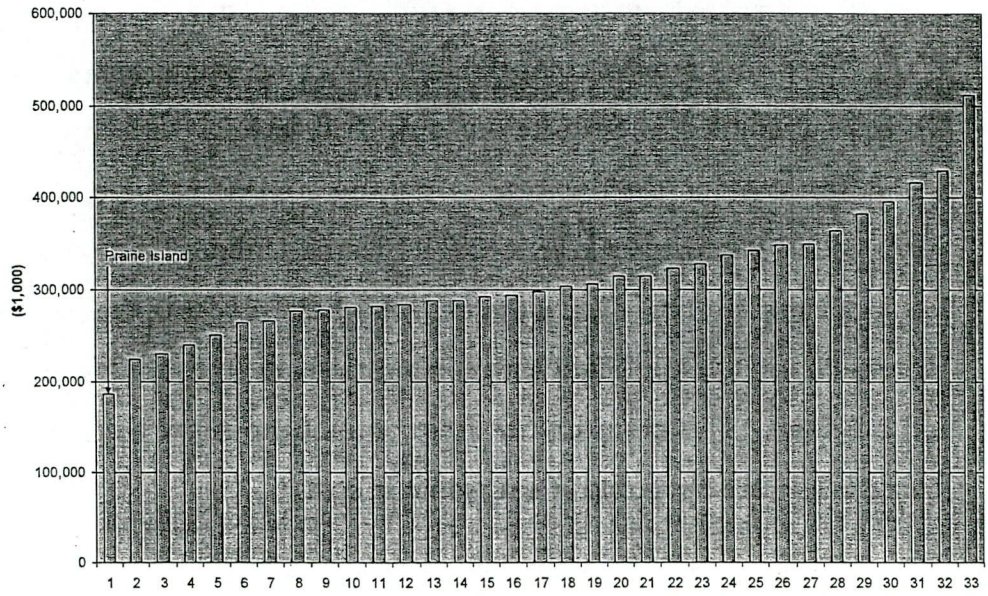


Figure 2 - 2013 Dual Unit Operating Costs



Q. PLEASE EXPLAIN HOW MONTICELLO AND PRAIRIE ISLAND COMPARE TO OTHER NUCLEAR UTILITIES IN TERMS OF STAFFING AND OPERATING COSTS.

A. Our plants have been operated efficiently compared to other nuclear power plants in terms of staff and total O&M budget. Exhibit___(TJO-1), Schedule 3 provides comparative data from the EUCG on single and multi unit operating costs and staffing levels for U.S. nuclear plants.

V. TEST YEAR NUCLEAR CAPITAL COSTS

Q. WHAT CAPITAL INVESTMENTS IS THE COMPANY MAKING IN ITS NUCLEAR FACILITIES?

A. Between 2009 and 2015, the Company will have invested over $1.5 billion in its nuclear facilities. Approximately $699.5 million will go into service in 2013.

Q. HOW MUCH HAS THE NUCLEAR RATE BASE GROWN FROM 2011 TO THE TEST YEAR?

A. We have added approximately $800 million to rate base from the last rate case to the 2013 test year.

A. Strategic Major Investments

Q. WHAT ARE THE COMPANY'S STRATEGIC MAJOR INVESTMENTS IN THE TEST YEAR?

A. The test year budget for capital expenditures on the Company's strategic major projects at its nuclear facilities includes the following as shown in Table 3 below:

Table 3 Strategic Major Investments

Capital Cost (Millions)	Prairie Island	Monticello
Life cycle management and power uprates	$ 86	$ 72
Steam generator replacement	156	--
Total 2013 strategic/major projects	$ 242	$ 72

I discuss each of these major projects in more detail below.

1. Monticello

a. Life Cycle Management and Extended Power Uprate

Q. PLEASE DESCRIBE THE BENEFIT OF THE MONTICELLO LCM/EPU PROJECT.

A. The LCM/EPU project will support continued operations at the plant, provide improved reliability and safety margins, and add approximately 71 MW of additional capacity. We expect these investments will prevent ongoing operation and maintenance expenses from increasing. The plant is a reliable resource that produces no greenhouse gases or emissions associated with acid rain or smog, and has provided low-cost electricity to our customers over the

last forty-two years. With the improvements we are making today, we expect the plant will continue to serve the needs of our ratepayers through 2030.

Q. PLEASE PROVIDE AN UPDATE ON THE MONTICELLO LCM/EPU PROJECT FROM THE LAST RATE CASE.

A. At the conclusion of our last rate case, the amended license and completion of the LCM/EPU project at Monticello was anticipated to occur in the Fall of 2012. The implementation schedule has changed since that time because of the delay in the NRC's review of our license amendment application and the need to rework equipment that failed to meet performance specifications.

The equipment performance issues have now been resolved and the equipment is expected to be delivered in time to be installed during the 2013 outage. However, the NRC's review is still in process and we now expect to complete the license proceeding in 2013.

Q. PLEASE DESCRIBE THE WORK REMAINING TO BE COMPLETED AS PART OF THE LCM/EPU PROJECT.

A. The projects below remain in the construction phase. While the work to be performed in the 2013 outage goes beyond the individual projects described, these are the primary investments necessary to support the LCM/EPU:

- *13.8 kV system.* This project includes the replacement and upgrade of the existing electric distribution system, including switchgear, controls, relaying and associated cable to the major station loads of the reactor feedwater pumps, the condensate pumps and the reactor recirculation pumps. This project also include the replacement of the reactor recirculation MG set drive motors and replacement of

the 1R and 2R transformers that will supply power to the new 13.8 kV busses and the existing 4 kV safety busses.

- *Reactor Feedpumps and Motors.* This work will increase the capacity of the reactor feedwater system by replacing the 13-series feedwater heaters, the feedwater pumps and motors, and the reactor recirculation motor. The existing pumps were original plant equipment and parts were no longer available and replacing them was necessary under LCM. In addition, the existing pumps and motors could not support operations under EPU conditions.
- *Feedwater heaters.* Six of the 10 feedwater heaters required replacement to support LCM/EPU. Routine inspections of the feedwater heaters indicated long term degradation of the tubes.
- *Condensate Pump Replacement.* The condensate pumps are a booster pump to provide water to the reactor feedpumps. With the increased flow requirements of the feedwater system, the condensate pumps also need to have a corresponding increase in capacity. The pumps and motors will be replaced to allow for this increase in flow. The sparger for the recirculation will also be increased in size. These improvements will support operations at uprated conditions, and increase safety margins by providing more capacity to move water to the feedpumps.
- *Completion of the Moisture Separator Drain Tank Injection.* This will include building an additional injection line to inject cold water into the Drain Tank. This will reduce component wear and improve efficiency of operations.
- *Completion of the #11 and #12 Feedwater Heater Drain Lines.* This work will include replacing a 12-inch pipe with a 14-inch pipe to increase

the steam provided to the feedwater heater. The increased steam flow to the feedwater heaters will improve the system's efficiency and improve safety margins.

In comparison to about 700 to 1200 employees for a typical refueling outage, we expect to have approximately 2,500 personnel on site during the Spring 2013 outage at Monticello to assist with the completion of the LCM/EPU project.

Q. WHAT ARE THE ESTIMATED TOTAL COSTS FOR THE PROJECT?

A. The current total project budget approved by the Xcel Energy Inc. Board of Directors last December is $587 million. The Company has spent approximately $503 million on the project as of October 31, 2012. See Exhibit___ (TJO-1), Schedule 4 outlining the costs incurred and forecast for this project by year.

This summer we reviewed an updated estimate of costs from our vendor, Bechtel, based on their completion of detailed work packages for EPU activities to be completed during next spring's outage. Bechtel's estimate, which included an increase in contingency costs, came in above the amounts included in the $587 million budget approved by the Board. We are working with Bechtel to minimize their cost increases for the project, but recognize that final costs will exceed the budget established prior to the completion of the detailed work packages by Bechtel.

Q. HAS THE COMPANY EXPERIENCED AN INCREASE IN PROJECT COSTS SINCE THE LAST RATE CASE?

A. Yes. As a result of our experience in the Spring 2011 outage, we continued to review the work that remained to be completed during the 2013 refueling outage and to re-estimate based on the lessons learned in 2011. We recognized our initial estimate was too low, as the actual costs of implementation during 2011 demonstrated.

Q. HOW DID THE COMPANY DEVELOP ITS FINAL ESTIMATE?

A. The estimate was the result of more detailed engineering and work package planning, completed during and after our work in the 2011 outage. These engineering and work package changes were necessary to address new regulatory requirements and conditions encountered during the outage.

As we moved forward with implementation of the project, we designed our project to comply with existing regulatory requirements. During the course of the NRC's review of our license amendment request, their acceptance criteria for several areas changed, including, for example, requirements for steam dryers and analysis of line breaks in high-energy systems (such as feedwater). During the 2011 outage, we considered such analysis and determined that the prior design was not going to meet the new requirements. Consequently, we revised the designs to accommodate the new requirements, which resulted in updated cost estimates. In addition, our initial estimates were based on a detailed review of the plant, but the actual condition of the systems and need for upgrades could not be fully known until we moved into implementation when the plant was offline. We were then able to take a closer look at the existing systems and perform more detailed engineering and work package planning.

As we commenced the final planning for this large capital project, we also found there would be significant benefits, especially in terms of improved safety margins and operating efficiencies, from accelerating some LCM work that had been planned for a later time period. I discuss some examples of such projects later in my testimony.

Q. PLEASE DESCRIBE THE PRIMARY COST INCREASES FROM THE START OF THE PROJECT UNTIL TODAY.

A. While there were cost increases overall, the most significant cost increases have related to four major modifications: 1) steam dryer acoustic monitoring and replacement of the steam dryer; 2) installation of the 13.8 kV electrical distribution system; 3) replacement of reactor feedwater pumps, valves, flow transmitters, and feedwater heaters; and 4) replacement of the condensate pump and impeller system and replacement of the condensate demineralizer system.

Steam Dryer

The project estimate initially included an evaluation and possible modification of the existing steam dryer, along the lines at what had been done at a similar commercial nuclear plant, Vermont Yankee. In that case, an EPU project had been approved and implemented without a steam dryer replacement. However, during the EPU application process for the Monticello plant, the NRC changed its criteria and subjected steam dryers to heightened scrutiny. This regulatory change increased the costs of the monitoring and evaluation work and led the Company to decide to purchase a new steam dryer rather than modify the existing one.

The new steam dryer has been installed and will significantly improve plant performance and reduce risk. The new dryer removes ten times as much water from steam as the previous model and results in far less corrosion on the related plant systems, thus reducing O&M costs over the life of the plant. The total cost of this project is approximately $37.7 million.

13.8 kV Distribution System

The 13.8 kV electrical distribution system was not within the original scope of work for the project. The cost of this project is estimated at $64.1 million, before common cost allocations, and makes up a significant portion of the increase in total project cost.

The 13.8 kV electrical distribution system upgrade supports both EPU and LCM. Upgrading the existing 4 kV system to a 13.8 kV system is necessary to support the additional load created by the larger feedwater pumps and motors. However, the existing 4 kV system would have needed to be replaced during the remaining life of the plant. The cost difference between replacing the existing 4 kV system and the installation of the 13.8 kV system is estimated at less than one percent.

More importantly, the upgrade to 13.8 kV provides more safety margin at the plant by allowing separation of large loads in loss of power scenarios and more versatility for transient situations. The upgrade provides strategic safety benefits in light of emerging Fukushima requirements.

The primary cost increases for this project were largely the result of design issues encountered during project implementation. The final cost estimate is

the result of detailed engineering and work package planning performed as we moved into implementation. This engineering work identified improvements and necessary changes in system design that will improve operational efficiencies.

Replacement of Reactor Feedwater Pumps and Related Equipment

In a boiling water reactor, reactor feed water pumps supply water to the reactor where the water is heated to produce steam. To meet the increased demand for both steady-state and transient conditions associated with the EPU, the feed water pumps and motors needed to be replaced with different models. Additionally, replacement of the feedwater drain and dump valves and feedwater heaters was necessary as part of LCM as the existing valves and heaters were more than 40 years old, making maintenance increasingly difficult. The replacement of the feedwater heaters was sized slightly larger in order to improve system efficiency and support the EPU.

After the initial estimate was developed, the project team determined the existing feedwater pumps should be replaced with larger capacity pumps, which increased both equipment costs and required additional modifications related to equipment and supporting systems. These related modifications included a change-out of the level transmitters at all four heaters, foundation modifications, and additional welds. Although the replacement of the pumps and equipment increased the costs of the project, these modifications are expected to save costs in the long term since all of the pumps would ultimately need to be replaced during the remaining life of the plant. Further, this combination of pumps and equipment allows plant operators to more

effectively manage water levels in the vessel, which is critical in ensuring fuel and core protection.

By making these investments early, we benefit from the increased safety margins and operational efficiencies for the entire remaining life of the facility. The total cost of this work is approximately $103.9 million, before common cost allocations.

Condensate Systems

Condensate pumps move water from the hot well of the condenser to the reactor feed water pumps. The reactor feed water pumps supply water to the reactor where it is heated to produce steam. In order to meet the increased demand for water to the reactor feed water pumps, the condensate pumps need to be replaced with different models.

The modification to the condensate systems includes several items that were added to the scope of the project after the initial estimate was developed. These additions were largely the result of not being able to access the critical areas until the plant was offline.

Accordingly, subsequent to the initial estimate, we determined existing wiring should be replaced at the time of implementation, and more tubing and supports should be included. However, because these pumps and related equipment would need to be replaced during the remaining life of the plant, it made sense to finish the work with the LCM/EPU implementation. Earlier implementation adds to plant reliability and safety margins and is expected to

reduce costs long-term. The total cost of this project is approximately $94.4 million, before common cost allocations.

Q. WILL ALL OF THE MONTICELLO LCM/EPU PROJECTS PLACED INTO SERVICE BE USED AND USEFUL IN THE TEST YEAR?

A. Yes. At each phase of the LCM/EPU Project as equipment has been installed, during the 2009 refueling outage and the 2011 refueling outage, it has been placed into service to support generation of electricity at the thermal power level authorized under the current NRC operating license. Similarly, it is necessary for the equipment that will be installed during the Spring 2013 outage to be in-service for Monticello to operate and produce power at the current power level. As such, the equipment will be used and useful.

2. Prairie Island

a. Life Cycle Management and Extended Power Uprate

Q. PLEASE DESCRIBE THE LCM AND EPU PROJECTS AT PRAIRIE ISLAND.

A. The MPUC in 2009 also approved an EPU at Prairie Island that would add 82 MW per unit or 164 MW total. On March 30, 2012, we filed a Notice of Changed Circumstances with the MPUC noting that recent analyses demonstrated the low pressure turbine was no longer cost-effective and, as a result, the combined additional MW from the update will be limited to 135 MW.[4] Additionally, operating the plant at a higher thermal power will require an NRC amendment to the plant's operating license. Due to delays in the NRC's review of our license amendment for the EPU, we proposed a delay in implementation of the uprate project until approximately 2016 and 2017. In October of this year, we filed additional analysis with the MPUC

[4] Docket No. E002/CN-08-509.

demonstrating that by extending the fuel cycle under non-EPU conditions, the resulting cost-benefits were about equal for pursuing the EPU or not pursuing the EPU. Whether the EPU is still the right choice for our customers is being addressed in that docket. We have discontinued work on the project while the issue of whether to proceed is being reviewed.

Q. ARE THERE MAJOR CAPITAL PROJECTS AT PRAIRIE ISLAND IN THE TEST YEAR THAT ARE SEPARATE FROM THE EPU?

A. Yes. In addition to the EPU project, a number of activities are needed at Prairie Island to support the extension of the operating license by another 20 years. We refer to these activities collectively as the LCM project.

Q. IS THE LCM PROJECT INTEGRATED WITH THE EPU PROJECT AT PRAIRIE ISLAND?

A. Initially it was. Our plan at the time of applying for the approval of the uprate at Prairie Island was to perform both LCM and EPU activities under a combined project work schedule (as we are doing at Monticello) because much of the work would be on integrated equipment, and could be done more efficiently during the same outages.

However, now that we foresee likely delays in how soon the EPU activities can be done at Prairie Island pending regulatory reviews and approvals, or even termination of the EPU project, we believe we must move forward with LCM activities in order to properly upgrade and update plant equipment to support extended operation through 2033-2034. Consequently, we have scheduled some LCM work to proceed at Prairie Island while the status of the EPU project is pending regulatory review.

Q. ARE THERE ANY COSTS RELATED TO THE LCM AND EPU PROJECTS AT PRAIRIE ISLAND INCLUDED IN THE 2013 TEST YEAR?

A. Yes. The Company has budgeted approximately $86 million in capital expenditures in the test year 2013 for the Prairie Island LCM work, mainly for generation step-up transformers and other work to support the steam generator replacement. We note that the EPU project is currently on hold pending MPUC review and that EPU investments for Prairie Island are not proposed to be placed in-service in the test year.

b. Steam Generator Replacement

Q. PLEASE DESCRIBE THE STEAM GENERATOR REPLACEMENT PROJECT AT PRAIRIE ISLAND.

A. Extending the operating license and life of Prairie Island will involve investments over a number of years to prepare Units 1 and 2 for 20 additional years of operation. Unit 1 steam generators were replaced in 2004 and will support operation through the license renewal period. The replacement of Unit 2 steam generators will be completed in 2013.

Q. WHAT COSTS RELATED TO THE STEAM GENERATOR REPLACEMENT PROJECT AT PRAIRIE ISLAND ARE INCLUDED IN THE 2013 TEST YEAR?

A. Approximately $285 million will be placed into service in the test year for this project. However, because these amounts will be placed into service at the very end of the year, the impact on the revenue requirement is very small. The Commission recently granted the Company's request for advance determination of prudence (ADP) for this steam generator project in Case No.

PU-10-127. Please see the Direct Testimony of Ms. Heuer for a discussion of the overall revenue requirements.

B. Dry Cask Storage

Q. PLEASE DESCRIBE THE DRY CASK STORAGE CAPITAL PROJECT S.

A. Our dry cask storage investments relate to facilities needed to store spent nuclear fuel on site, pending the establishment of a permanent federal storage facility.

Q. ARE THERE ANY DRY CASK STORAGE PROJECT COSTS INCLUDED IN THE TEST YEAR FOR MONTICELLO?

A. Yes. On October 23, 2006, the MPUC granted a Certificate of Need for up to 30 additional dry casks to store spent nuclear fuel on-site in an independent spent-fuel storage installation to support an additional 20 years of operation at Monticello. Ten storage canisters were loaded in 2008, an additional 10 canisters will be loaded in 2013, and the last 10 canisters will be loaded in 2016. The Company will make significant investments related to the additional dry-cask storage, and the 10 canisters loaded in 2013 will be placed into service in 2013. The total additions included in the test year related to this installation are $36.9 million.

Q. ARE THERE ANY DRY CASK STORAGE PROJECT COSTS INCLUDED IN THE TEST YEAR FOR PRAIRIE ISLAND?

A. Yes. On December 18, 2009, the MPUC issued an Order granting a Certificate of Need for up to 35 additional dry casks to store spent nuclear fuel on-site to support the additional 20 years of operation. We have a contract for the manufacture and delivery of 18 casks between 2013 and 2019.

At this time, we anticipate loading and placing in service 6 casks in 2013. The total additions included in the test year related to this installation are $35.6 million.

C. Mandated Compliance

Q. PLEASE DESCRIBE THE MANDATED COMPLIANCE CAPITAL PROJECTS.

A. Mandated compliance projects (Table 4 below) are in response to regulatory requirements imposed on the Company's nuclear operations (primarily by the NRC), and for the test year include capital expenditures for the following items:

Table 4 - Compliance Projects

Capital Cost (Millions)	Prairie Island	Monticello
License Renewal Requirements	$11.0	$ --
Fire Protection	$ 7.3	$ 1.0
Fukushima external events	$ 3.0	$ 3.2
Cyber Security	$ --	$ 1.6
Other	$ 1.2	$ 0.2
Total Mandated Compliance	$ 22.5	$ 6.0

Q. WHAT IS THE STATUS OF THE LICENSE RENEWAL FOR PRAIRIE ISLAND?

A. In June 2011, the NRC granted the Company renewal of the operating licenses for the two nuclear reactors at Prairie Island for an additional 20 years — until 2033 and 2034. The license renewal was granted subject to a number of requirements which must be addressed in a timely manner. As reflected in Table 4, the Company has budgeted approximately $11 million in capital expenditures in the test year 2013 for these required activities to be completed

prior to expiration of the initial license, including updating the licensing design basis of the plant.

Q. DO YOU ANTICIPATE COMPLIANCE COSTS TO CONTINUE TO RISE?

A. Yes. As the NRC, Federal Emergency Management Administration (FEMA) and other regulatory agencies enhance and revise regulations in response to new technology and new security threats, we anticipate additional increases in costs necessary to comply with new and revised regulations.

Q. WHAT ARE SOME OF THE KEY COMPLIANCE-RELATED PROGRAMS AFFECTING THE COMPANY'S COSTS SINCE THE LAST RATE CASE?

A. In addition to the regulatory changes requiring additional personnel discussed later in my testimony, key regulatory programs affecting the Company's costs are NRC initiatives related to cyber security and fire protection.

In addition, in response to the 2011 incident in Fukushima, Japan, the NRC has issued information requests under 10 CFR 50.54(f) and the industry as a whole is responding. Most of the responses and compliance costs at this time are related to re-analyzing existing data and conducting new analyses with information not previously available.

D. Reliability, Improvement and Facilities Expenditures

Q. ARE THERE OTHER SIGNIFICANT CAPITAL INVESTMENTS OUTSIDE OF THE PROJECTS DISCUSSED THUS FAR IN YOUR TESTIMONY?

A. Yes. The Company will continue to make ongoing capital investments at both Monticello and Prairie Island, as it has always done, that are separate from the strategic major projects, dry cask storage, and mandatory compliance work I

have already discussed. For the test year, these include equipment reliability and system improvement expenditures (approximately 80 projects totaling $45 million for both sites) and facility expenditures (approximately 15 projects totaling $6 million for both sites).

Q. HAVE THERE BEEN ANY CHANGES TO THE FUEL BUDGET?

A. Yes. The nuclear fuel forecast was updated after the capital budget was finalized and an adjustment was made to reflect this change for the test year. The revenue requirement associated with nuclear fuel is addressed further in Ms. Heuer's Direct Testimony.

VI. TEST YEAR NUCLEAR O&M COSTS

Q. HOW IS YOUR TESTIMONY DISCUSSING THE TEST YEAR NUCLEAR O&M COSTS ORGANIZED?

A. I discuss the O&M costs budgeted for the 2013 test year for our nuclear facilities, segregated into two categories: non-outage and outage-related. For this purpose, outage-related refers only to scheduled refueling outages, and does not include unplanned or forced outages (the cost of which are included in non-outage).

A. Non-Outage Costs

Q. WHAT TYPES OF NON-OUTAGE O&M COSTS ARE INCURRED IN THE OPERATION OF MONTICELLO AND PRAIRIE ISLAND?

A. There are two general categories of non-outage O&M costs associated with operating our nuclear plants: site costs (costs directly controlled by us); and non-site costs (costs not under our direct control). Non-outage site costs

include employee labor, non-employee contractors and consultants, costs for materials, employee expenses and other expenses. Non-site costs are made up of nuclear-related fees and security costs, and are considered non-outage in nature.

Q. PLEASE PROVIDE A SUMMARY OF 2011 ACTUAL NON-OUTAGE O&M COSTS COMPARED TO THE 2013 BUDGETED COSTS.

A. As shown in Table 5, non-outage O&M costs are projected to increase approximately $9.6 million from 2011 to the test year. This increase is due to a projected increase in non-outage site costs of $3.4 million and a projected increase in non-site costs of $6.2 million. Total O&M costs in the test year include post-budget adjustments of $11.0 million, as summarized on Schedule 6 and as discussed in Ms. Heuer's Direct Testimony.

I will discuss each of these O&M categories in Table 5 in more detail.

Table 5

Nuclear Generation Business Area O&M Costs – Non-Outage ($ in millions)

	2011 Actual Costs ($M)	Test Year Budgeted Costs[5] ($M)	Increase From 2011 Actual to Test Year Budget ($M)	% Change 2011 to Test Year	Average % Change Per Year
Non-outage Site Costs					
Labor	$125.9	$131.6	$ 5.7	4.6%	2.3%
Contractors & Consultants	37.5	32.0	(5.5)	(14%)	(7.3%)
Materials	14.6	16.8	2.2	15%	7.5%
Employee Expenses	4.3	4.2	(0.1)	(3.6%)	(1.8%)
Other	4.7	5.8	1.1	23%	12%
Non-outage Site Costs Total	$187.0	$190.4	$3.4	1.8%	0.9%
Non-Site Costs					
Nuclear Related Fees	$30.9	$34.8	$3.9	12.5%	6.3%
Security	24.9	27.2	2.3	9.1%	4.6%
Non-Site Costs Total	$55.8	$62.0	$6.2	11.0%	5.5%
Total Non-outage O&M	$242.8	$252.4	$9.6	3.9%	2.0%

1. Site Costs

Q. PLEASE DISCUSS THE NON-OUTAGE SITE COSTS INCLUDED IN THE TEST YEAR.

A. Non-outage site costs included in the test year are approximately $190 million and represent a cost increase of $3.4 million from 2011 actual costs, an average annual increase of 0.9 percent over the two years.

a. Labor Costs

Q. PLEASE DESCRIBE SITE LABOR COSTS FOR NON-OUTAGE ACTIVITIES.

A. Our 2013 test year reflects an increase of 94 employees over 2011 actuals. This number is based on an end of year total, so our budget does not assume that these are employees for an entire year. Our employees are responsible for the daily safe operation of our nuclear plants, and include plant operators,

[5] Includes post-budget adjustments of $11 million as summarized on Schedule 6 and as discussed in Company witness Ms. Heuer's Direct Testimony.

maintenance workers, health physicists, chemists and others. We note that requirements seldom go away, but new requirements and new guidance are being issued and we must staff to meet those new requirements. Some nuclear plant employees also work on scheduled outages, and their labor costs are excluded from the non-outage labor noted in Table 5.

Q. DO YOU SEE ANY CHALLENGES TO CONTROLLING FUTURE LABOR COSTS BEYOND THE TEST YEAR?

A. Yes. The nuclear energy industry is facing increased competition for experienced workers, which will contribute to a shortage of specialized and skilled labor. An analysis of Xcel Energy's non-bargaining nuclear employees shows that 15.6 percent are eligible to retire in 2012, increasing to 31.4 percent eligible to retire before 2018. For our bargaining unit employees, 11.8 percent are eligible to retire in 2012, increasing to 25.4 percent eligible to retire before 2018. In addition, the NRC's issuance of a new reactor license will further contribute to the competition for skilled nuclear workers.

We have developed a plan for recruiting and retaining the qualified work force that is needed to continue safe, reliable, and efficient electricity production at our sites. However, these are highly-skilled positions that can be difficult to fill. The recent departure of our Chief Nuclear Officer illustrates the mobility available to these employees. One new program we developed to help retain these valuable nuclear employees is a long term retention program initiated this year. The revenue requirement associated with this program is addressed further in Ms. Heuer's Direct Testimony.

Further, consolidation in the nuclear industry has put small plant owners at a disadvantage in a highly-competitive labor market. While we have had success in filling positions, we are currently seeing greater levels of attrition, as highly-skilled workers leave to work at other facilities around the country that provide either higher total compensation or a superior career path, because they can move through a larger number of opportunities at different facilities. As a result, we have moved to hire more employees, both in anticipation of potential retirements and in order to assure that we have adequate staffing levels. A review of compensation for certain Xcel Energy nuclear positions shows that we are below market levels. While we are taking steps to address these issues to better match the industry, this will result in additional upward-cost pressure going forward.

b. Materials Costs

Q. PLEASE DESCRIBE THE NON-OUTAGE COSTS FOR SITE MATERIALS.

A. Non-outage materials costs are increasing about 15 percent in the test year compared to 2011 actual costs (an average increase of about 7.5 percent per year). This increase reflects materials expected to be needed to meet the requirements of specific projects planned for 2013, in comparison to project requirements in 2011. Materials vary by project, with some being more labor-intensive and others requiring relatively more materials based on work being performed. We anticipate an overall increase of $2.2 million and this amount is reflected in the materials line item of Table 5

c. Employee and Other Expenses

Q. WHAT IS THE TREND IN EMPLOYEE AND OTHER EXPENSES FROM 2011 TO THE TEST YEAR?

A. Employee expenses include costs for employees to travel both within and outside the Company's service territory for business reasons. We have continued to critically review employee expenses and have been able to further reduce employee expenses in the test year by approximately $100,000 (3.6 percent) compared to 2011 actuals, an average decrease of 1.8 percent per year.

Other expenses are increasing about $1.1 million (23 percent) in the test year compared to 2011 actuals, mainly due to increased software maintenance and license costs. Continuing investments in software for nuclear engineering, security, analysis and reporting are resulting in higher ongoing costs to maintain updated versions and valid licenses for the software.

2. Non-Site Costs

Q. WHAT NON-SITE COSTS ARE INCLUDED IN THE TEST YEAR?

A. As shown in Table 5, total non-site costs included in the test year forecast were $62.0 million. Non-site costs are increasing approximately $6.2 million (11.0 percent) from 2011 actual costs to the test year budget, an average increase of 5.5 percent per year. Both types of non-site costs, regulatory fees and security, have experienced significant increases due to external requirements beyond our control.

a. Fees

Q. WHAT ARE THE NUCLEAR-RELATED FEES ASSOCIATED WITH MONTICELLO AND PRAIRIE ISLAND?

A. As shown in Table 6 below, nuclear-related fees include fees paid to the government agencies responsible for regulatory oversight, nuclear industry organizations, and nuclear equipment owner groups.

Table 6 Nuclear-Related Fees

Fee Type / Organization	2011 Actual Costs ($M)	Test Year Budgeted Costs[6] ($M)	Increase From 2011 Actual to Test Year Budget ($M)	% Change 2011 to Test Year	Average % Change Per Year
NRC	$19.4	$19.9	$0.5	2.7%	1.3%
FEMA/State EP	4.4	6.8	2.4	55%	27%
INPO	2.7	3.0	0.3	8.6%	4.3%
EPRI	2.2	2.5	0.3	11%	5.5%
NEI	0.8	0.8	0.0	1.9%	0.9%
Other (equipment owner and pooled inventory groups)	1.4	1.8	0.4	34%	17%
Total Fees	**$30.9**	**$34.8**	**$3.9**	**12.5%**	**6.3%**

Q. HOW ARE THE AMOUNTS OF THE NRC FEES DETERMINED?

A. The NRC is required by Congress to recover 90 percent of its annual budget through fees charged to licensees. Nuclear plant operators are charged a set annual fee per reactor each year by the NRC and, in addition, are charged on an hourly basis for additional plant-specific activities, such as the processing of operating license amendments or performance of inspections. Hourly fees charged to a licensee will go up or down based on the number of licensing actions or inspections that the NRC needs to undertake in a given year.

[6] Includes post-budget adjustments to Nuclear-Related Fees of $1.5 million as summarized on Schedule 6 and as discussed in Ms. Heuer's Direct Testimony.

Q. PLEASE EXPLAIN THE INCREASE IN TEST YEAR NRC FEES COMPARED TO 2011 ACTUALS.

A. Over the two-year period, NRC fees have increased approximately 2.7 percent in total, or an average of about 1.3 percent per year. Test year NRC fees include $4.7 million for activities specific to the Company's plants, and $15.2 million for an allocation of NRC general operating budgets. General NRC allocations in the test year represent an average annual increase of 3.4 percent from 2011 levels. This level of increase is lower than recent experience in NRC fee changes, based on steadily increasing NRC budgets being allocated to the nuclear operating licensees it regulates.

Q. DOES THE BUDGET INCLUDE AMOUNTS FOR ADDITIONAL INSPECTIONS THAT MAY BECOME DUE AS A RESULT OF REGULATORY PERFORMANCE AT MONTICELLO AND PRAIRIE ISLAND?

A. No. Our budget assumes only the baseline level of inspections.

Q. PLEASE EXPLAIN THE INCREASE IN TEST YEAR FEMA/STATE EMERGENCY PLANNING FEES COMPARED TO 2011 ACTUALS.

A. Over the two-year period, emergency planning (EP) fees assessed by the FEMA and state EP agencies have increased approximately $2.4 million (55 percent), or an average of about 27 percent per year. This increase is primarily due to NRC and FEMA regulations that have added requirements for Hostile Action Based Emergency Preparedness drills and the Homeland Security and Exercise and Evaluation Programs causing state and federal agency support staffs and programs to increase.

b. Security

Q. PLEASE DESCRIBE THE SECURITY COSTS FROM 2011 ACTUAL EXPENSES TO THE TEST YEAR BUDGET.

A. The NRC continues to monitor the threats to nuclear power plants and enhance the security of nuclear power plants by promulgating new security regulations. Security costs are budgeted to increase $2.3 million in the test year over 2011 actuals. This increase primarily reflects the addition of five employees, changes in overtime, wage increases, and contractual benefit rates.

B. Outage Costs

Q. PLEASE DESCRIBE HOW OUTAGE COSTS ARE BUDGETED.

A. The first step in developing the refueling outage budgeted costs is to define the scope of the outage. The scope of a refueling outage includes both routine 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. Initial cost estimates for completion of the work are based on historical estimates adjusted for labor or material cost changes that are known. Activities in the refueling outage scope are controlled under our work order process. A work order will define the work to be completed, the resource (internal or contract) responsible to complete the work, and the materials needed to support the work. Updated information on labor and material costs are incorporated as the work order progresses through the planning process leading up to the actual refueling outage.

Q. PLEASE DISCUSS OUTAGE COSTS INCLUDED IN THE TEST YEAR.

A. Similar to non-outage activities at the site, outage costs include employee labor, non-employee contractors and consultants, and other expenses. Outage costs incurred in the test year are approximately $91.9 million and represent a cost increase of $24.6 million from 2011 actual costs, an average annual increase of 18 percent over the two years.

Q. HOW ARE OUTAGE COSTS ACCOUNTED FOR IN THE TEST YEAR?

A. As Company Witness Dennis L. Koehl discussed in Case No. PU 10-657, the Commission approved a new accounting methodology in 2008 that allows outage costs to be deferred when incurred and then amortized over the period between refueling outages. Ms. Heuer discusses this process further in her Direct Testimony. Although we will perform two refueling outages in 2013, only a portion of the 2013 outage costs will be included in the test year as the total outage costs are spread out over the period between refueling outages.

Q. PLEASE EXPLAIN THE SCOPE OF THE OUTAGES PROPOSED FOR COST RECOVERY IN THIS CASE.

A. There were two refueling outages in 2012 and two refueling outages are planned to occur during the 2013 test year; partial costs of each of these outages are included in the test year. In addition, approximately $7 million from the 2011 Monticello refueling outage is proposed for recovery as the costs for that outage will not be fully amortized until the beginning of the Spring 2013 outage at Monticello. Please see Exhibit___(TJO-1), Schedule 5 for a breakdown of these costs.

1. Monticello

The Spring 2013 refueling outage at Monticello will have a longer duration than a normal refueling outage, as certain capital modifications are addressed in tandem with the O&M aspect of the outage. The capital modifications are related to implementation of the remaining LCM/EPU described above in Section V, Part A of my testimony. In addition, 10-year inspection work will be completed during this outage, as well as implementation of certain maintenance projects that, although not part of the LCM/EPU project, are required to support the LCM/EPU project. More days are needed to complete the routine outage work as a result of the simultaneous LCM/EPU project work being done. The test year also includes the final amortized costs of the 2011 refueling outage.

2. Prairie Island Unit 1

The 2012 refueling outage at Prairie Island Unit 1 is focused on refueling and routine maintenance and capital work items, including but not limited to: maintenance on the D1 and D2 Emergency Diesel Generators; electrical inspections of the Emergency Diesel Generators; completion of license renewal inspections that were committed to the NRC prior to the end of the initial license expirations in 2013; performance of the containment integrated leak rate test; preventative maintenance on electrical relays and breakers; replacement of equipment that is required by NRC to be Environmentally Qualified; containment polar crane preventative maintenance; and relay valve testing. We revised the budget for the fall 2012 refueling outage to account for the fact that we had originally estimated 35 days for outage length, but later determined that in order to accomplish the desired work the outage would be 45 days long. A post-budget adjustment to test year outage

amortization expense was made to reflect this 2012 outage change, as outlined in Exhibit___(TJO-1), Schedule 6, and discussed in Ms. Heuer's Direct Testimony.

3. Prairie Island Unit 2

The test year includes outage costs for the Spring 2012 and Fall 2013 refueling outages for Prairie Island Unit 2.

The 2012 Spring refueling outage was focused on: refueling and routine maintenance and capital work items, including but not limited to replacing safety related battery chargers; auxiliary reserve transformer maintenance; completion of license renewal inspections that were committed to the NRC prior to the end of the initial license expirations in 2014; preventative maintenance on electrical relays and breakers; replacement of equipment that is required by NRC to be Environmentally Qualified; and the Local Leak Rate Testing program.

The Fall 2013 refueling outage is longer than a normal refueling outage, as certain capital modifications are addressed in tandem with the O&M aspect of the outage. In 2013, the capital modifications are related to replacing Unit 2's two steam generators to support 20 years of extended operation described in my testimony. The outage work not related to the steam generators replacement will be routine refueling outage work.

Q. YOU INDICATE THAT THE IMPLEMENTATION OF THE LCM/EPU PROJECT AT MONTICELLO WILL INCREASE THE NON-LCM/EPU PROJECT COSTS. IS THE COMPANY MAKING ANY EFFORT TO REDUCE THIS IMPACT?

A. Yes. We are performing all of the LCM/EPU work we can outside of an outage. Whether we can perform this work will depend on: 1) whether we have access when the plant is on-line; and 2) whether the work can be completed when the plant is on-line. For example, some areas of the plant do not have high radiation levels while the plant is operating and we can perform work in those areas while the plant is on-line. In addition, we can perform some work on redundant systems while the plant is operating.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company's nuclear generating facilities at Monticello and Prairie Island remain critical components of our generation portfolio, consistently providing cost-effective and reliable electric generation for our ratepayers. We have managed the overall costs of the facilities well, and even with the increases in this rate case, the costs for our plants are comparable to plants across the country. These facilities have some of the lowest production costs on our system, and support the state's energy policy by emitting no greenhouse gases. The plants have achieved safe, reliable and cost-effective operations. The investments outlined above will help ensure these facilities are available to serve our customers in the coming years.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-12-___

AFFIDAVIT OF
Timothy J. O'Connor

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Timothy J. O'Connor

Subscribed and sworn to before me, this 11th day of December, 2012.

Notary Public

ELLEN C. CHRISTOFFERSON
NOTARY PUBLIC - MINNESOTA
My Commission Expires January 31, 2015

Statement of Qualifications

Timothy J. O'Connor
Acting Chief Nuclear Officer

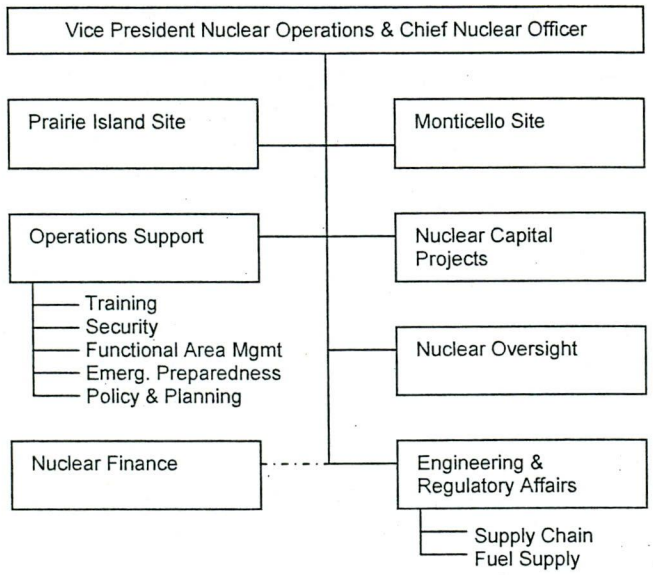
Tim O'Connor is acting chief nuclear officer for Xcel Energy. He is responsible for all Xcel Energy nuclear activities in Minnesota at the Monticello and Prairie Island nuclear generating plants (operated by NSP-Minnesota and its parent company, Xcel Energy.)

Mr. O'Connor joined Xcel Energy in 2007 as the site vice president of the Monticello plant. Earlier this year, he was appointed vice president of engineering and nuclear regulatory compliance and licensing.

He has 30 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.

Nuclear Generation
Operations – Support Functions – Activities



Major Functions

The Nuclear Generation Operations and Support organization oversees Xcel Energy's nuclear plant operations and the required services to support those operations. The leaders of the areas listed below collaborate as a Nuclear executive team for the oversight of business planning, project prioritization and funding, regulatory compliance, and other matters.

Key Organizations and Activities:

- **Monticello and Prairie Island Sites** – The Site Operations organization at each plant oversees the safe day-to-day operation of the generating plant and the strategic implementation of all functions performed at/for the site. These functions, which include regulatory/environmental compliance, security, emergency planning, capital projects, training and financial management, have the common objective of assuring the collective operations of the site to meet Nuclear and Company expectations.

- **Nuclear Capital Projects** oversees the planning and execution of capital projects for nuclear generating units. Nuclear's capital projects include initiatives mandated by regulators, upgrades to equipment to maintain reliability, efforts to improve operating performance, storage of spent nuclear fuel, and facilities.

- **Operations Support** provides support to plant production and maintenance, staff training, safety oversight, and radiological protection through the following areas:
    - *Training* – Responsible for overall coordination of fleet training programs to assure delivery of effective training that meets regulatory commitments and business needs.
    - *Security* – Responsible for maintaining and implementing effective security measures for nuclear generating sites to meet applicable regulatory requirements. This includes programs for access authorization, fitness for duty, and physical protection of the facilities.
    - *Functional Area Management* – Responsible for oversight and fleet support activities in Operations, Maintenance, Production Management, Radiation Protection/Chemistry, Performance Assessment, Human Performance and Safety.
    - *Emergency Preparedness* – Directs fleet strategic emergency preparedness activities.
    - *Policy & Planning* – Provides support for strategic business and regulatory planning.

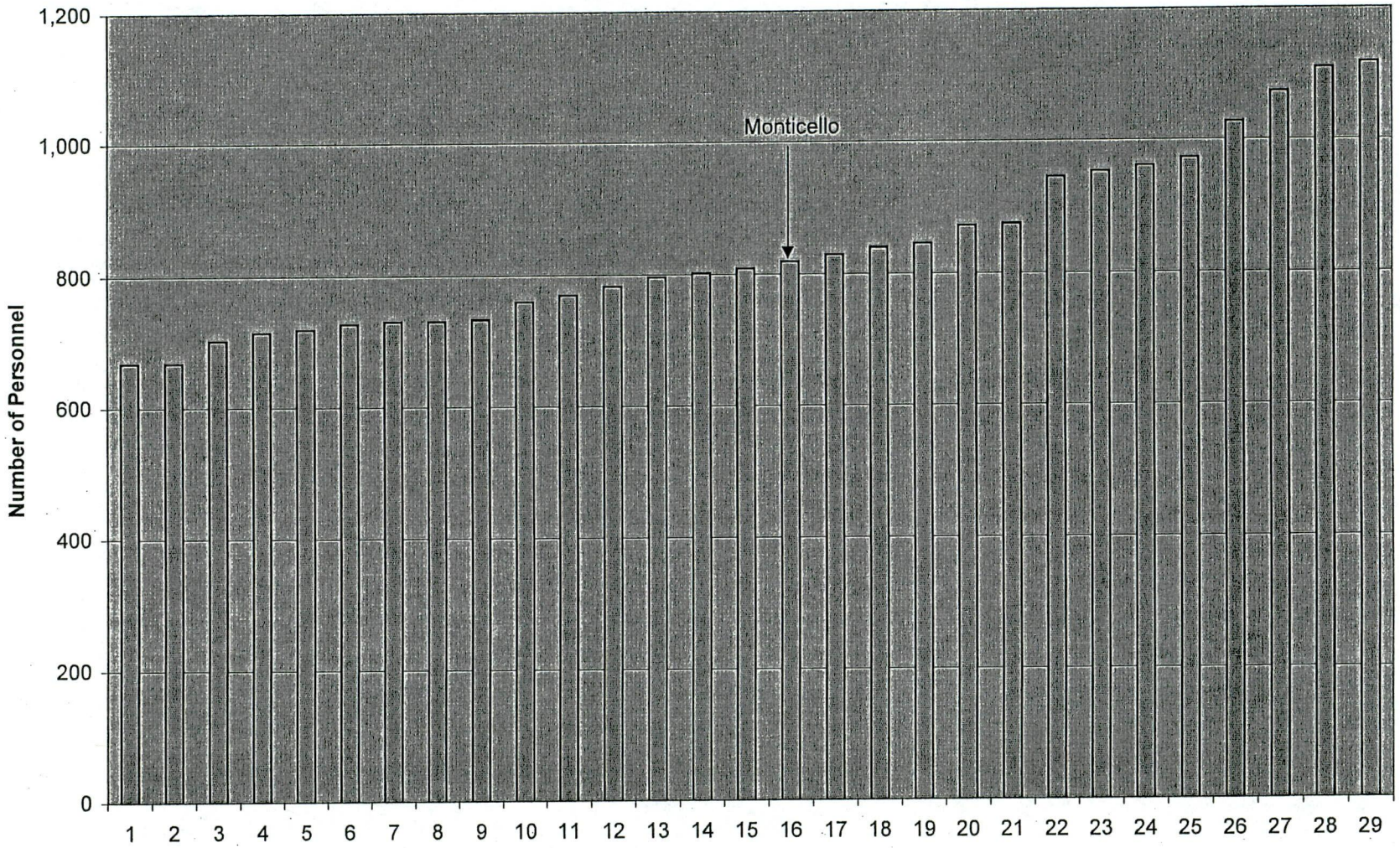
- **Nuclear Oversight** is responsible for Nuclear's quality assurance and corrective action programs. This area is responsible for establishing, maintaining, and interpreting Xcel Energy's quality assurance policies and procedures; establishing the requirements for assessor and inspector certification; managing the overall independent assessment process and establishing quality control practices and policies for quality verification activities. Additionally Nuclear Oversight provides for supplier evaluation; the conduct of supplier assessments or surveys (including their sub-tier suppliers); and verification that supplier quality assurance programs comply with Xcel Energy requirements. This organization has the authority to stop work at the sites and headquarter offices.

- **Engineering & Regulatory Affairs** provides support in several areas.
    - *Engineering* is a core competency of Nuclear in its operation, maintenance and construction activities. Engineering is responsible for program engineering, nuclear analysis and design, and day-to-day engineering support at the sites.
    - *Regulatory Affairs* supports compliance and licensing, which are also significant responsibilities for maintaining safe and reliable nuclear operations. This area manages the NRC regulatory interfaces, responding to NRC regulatory inspections and requests, developing licensing action requests for NRC regulatory approval.
    - *Supply Chain* is responsible for procurement of commodities, equipment, parts, components and services, including warehouse operations at the generating sites.
    - *Nuclear Fuel Supply* provides planning and procurement for nuclear fuel, including the long-term storage of spent fuel.

- **Nuclear Finance** provides accounting, budgeting and reporting support for Nuclear operations, including governance oversight for capital projects.

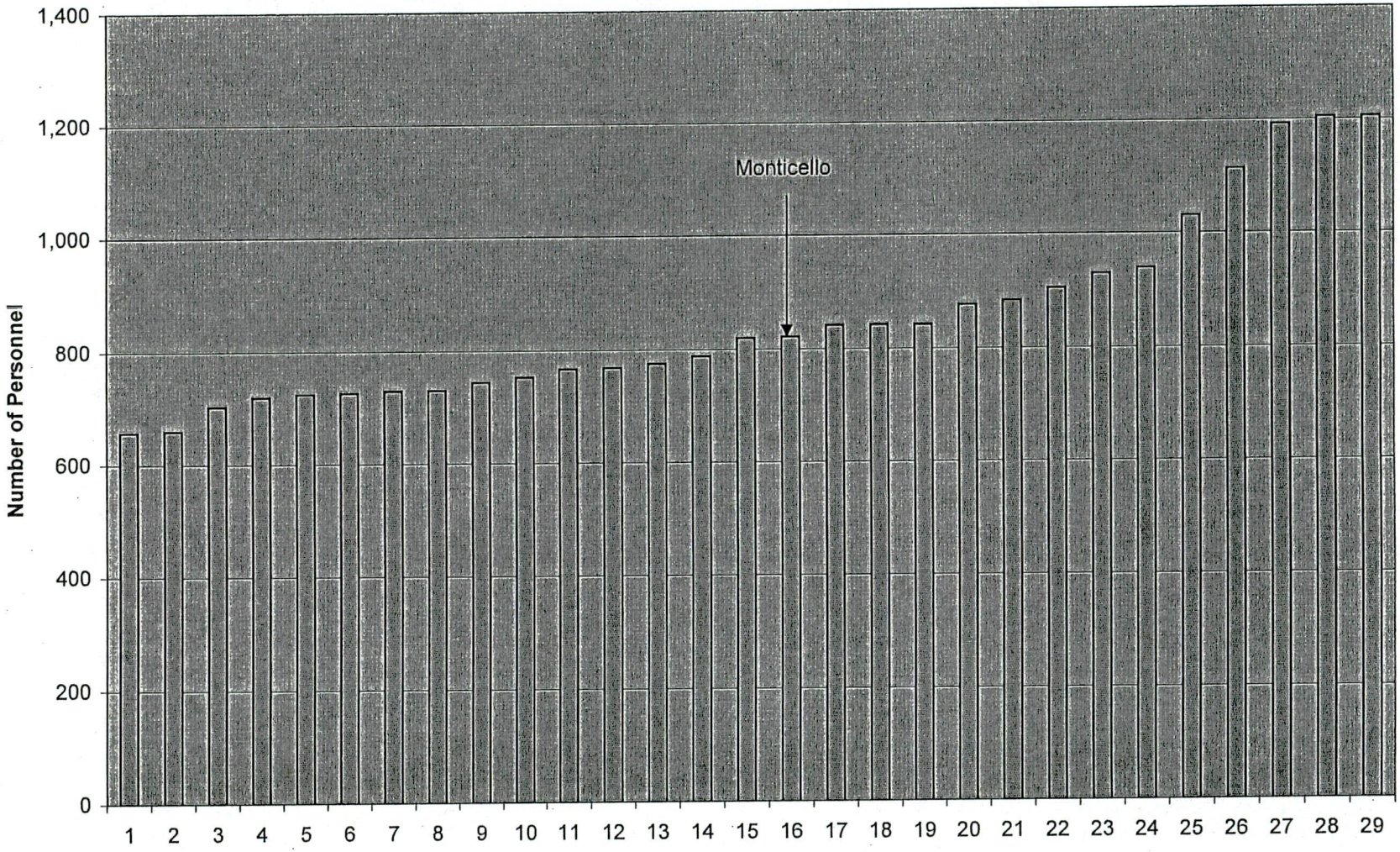
Northern States Power Company
Electric Utility - North Dakota

2009 Single Unit Staffing



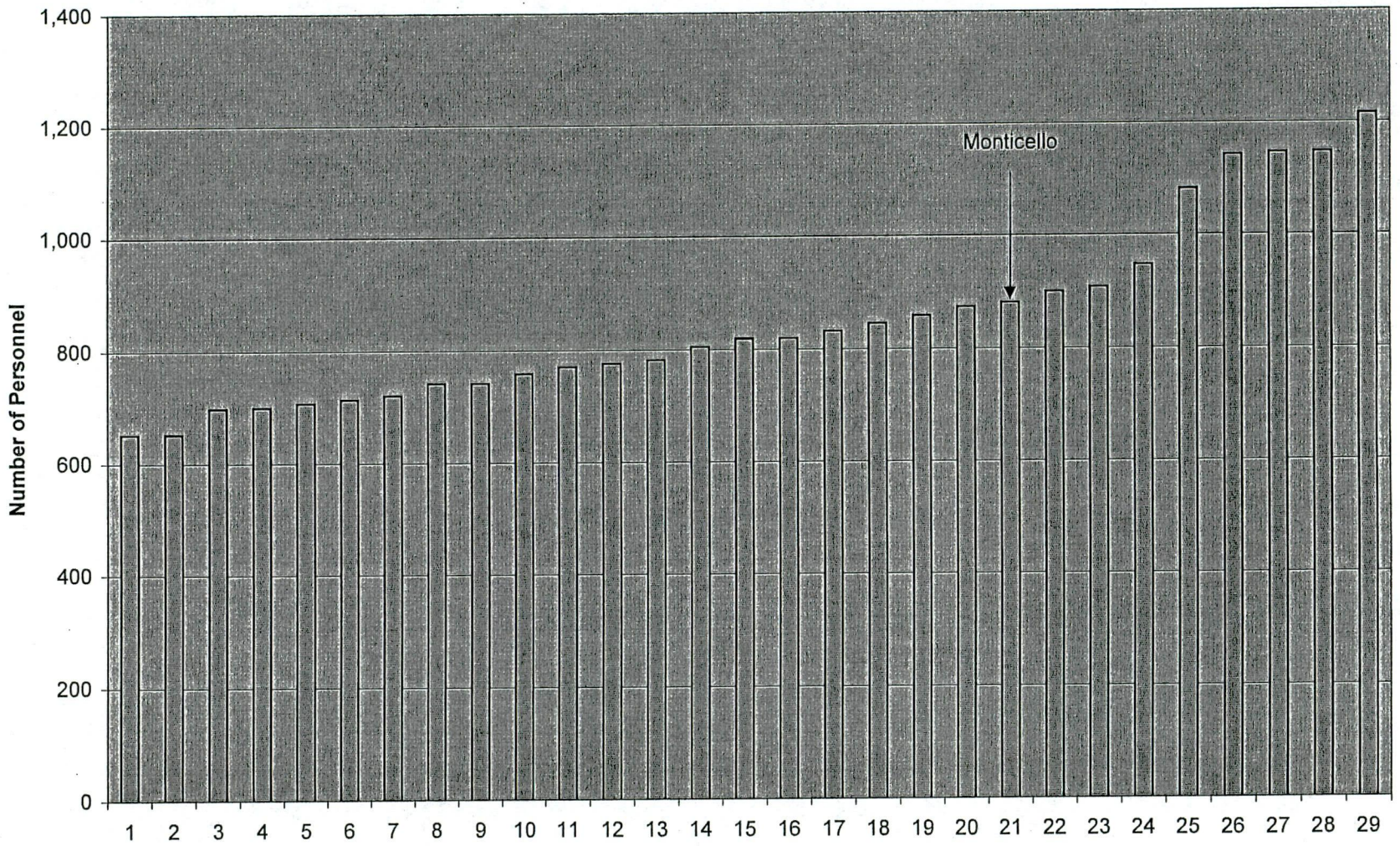
Northern States Power Company
Electric Utility - North Dakota

2010 Single Unit Staffing

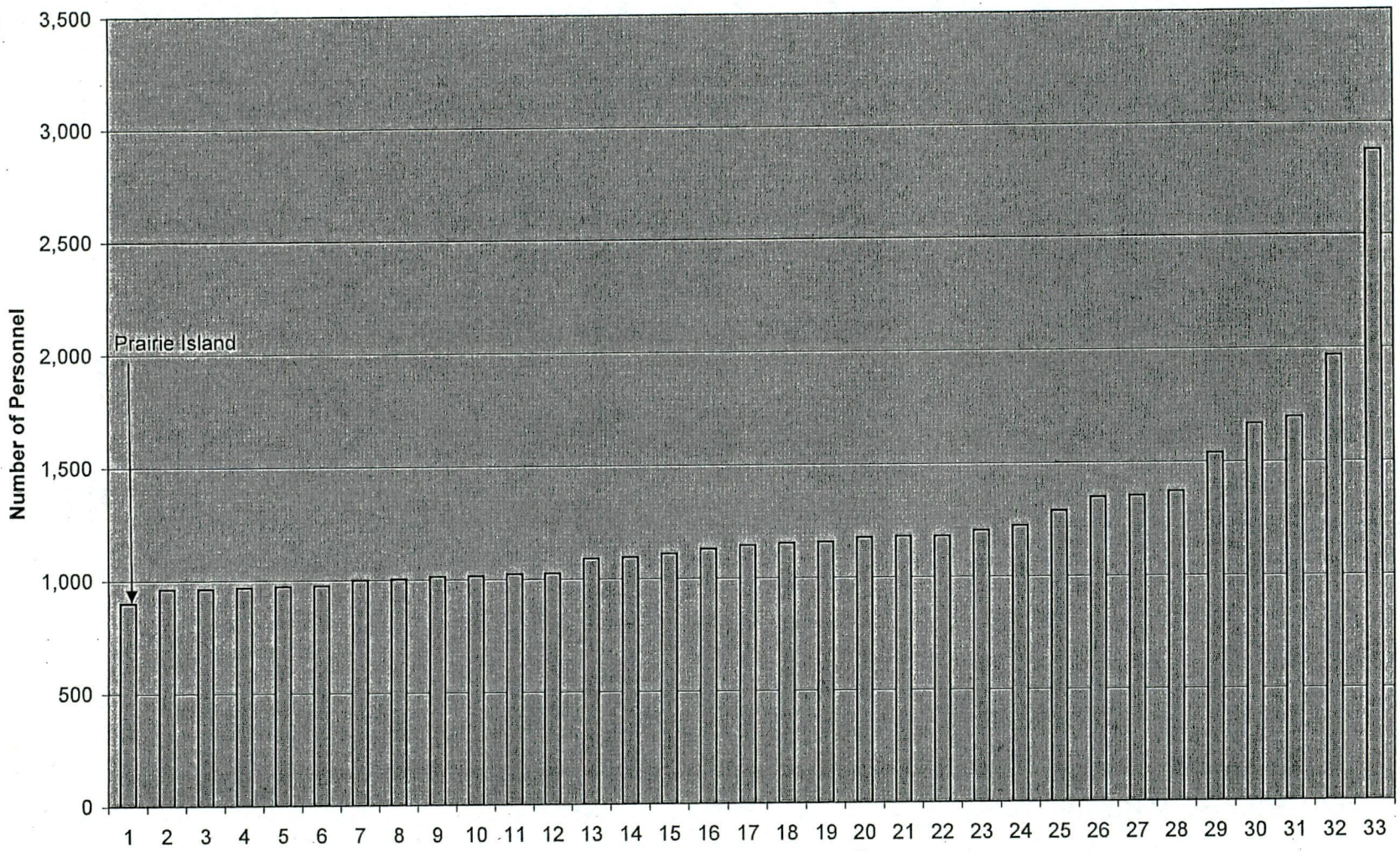


Northern States Power Company
Electric Utility - North Dakota

2011 Single Unit Staffing

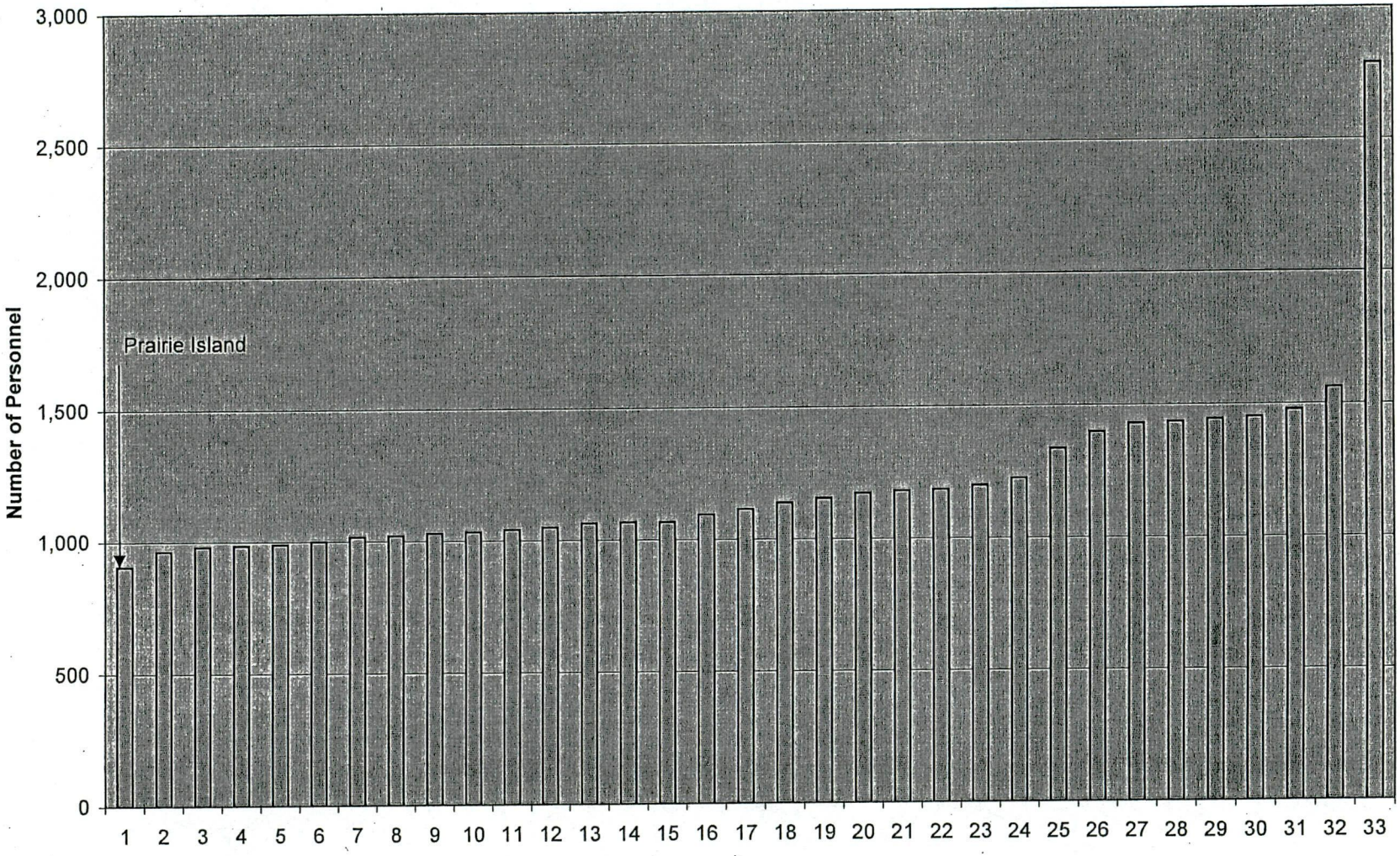


2009 Dual Unit Staffing



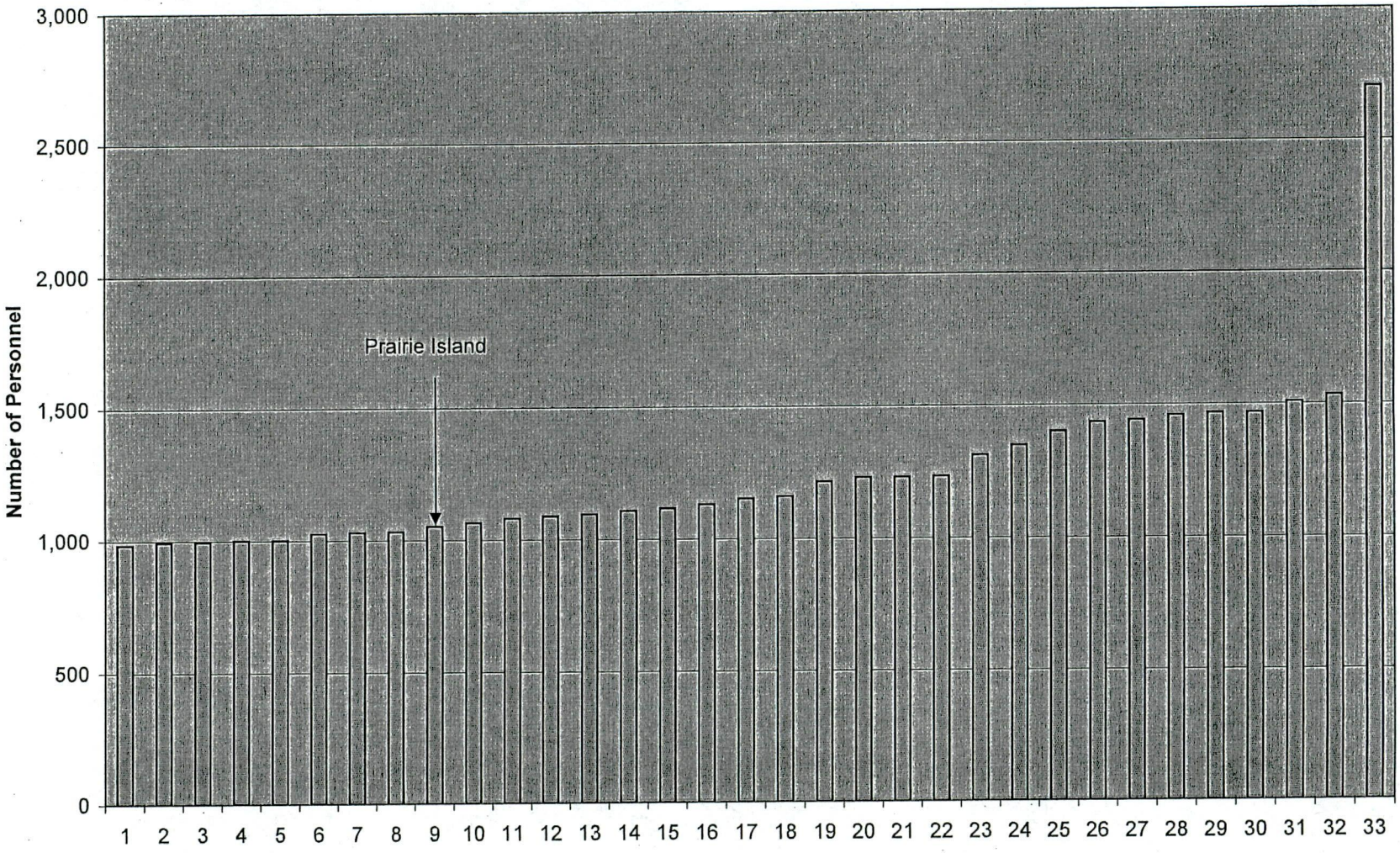
Northern States Power Company
Electric Utility - North Dakota

2010 Dual Unit Staffing

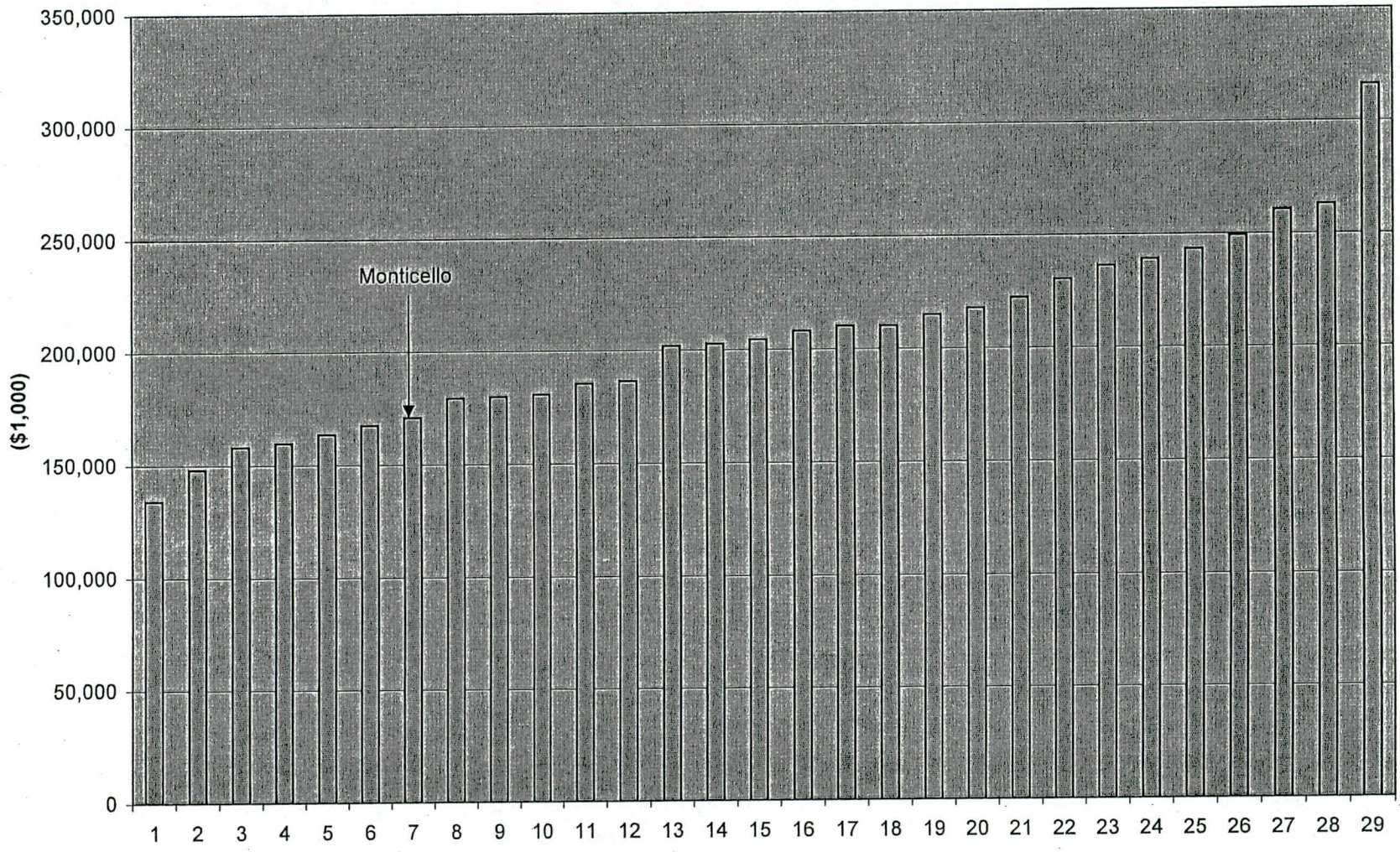


Northern States Power Company
Electric Utility - North Dakota

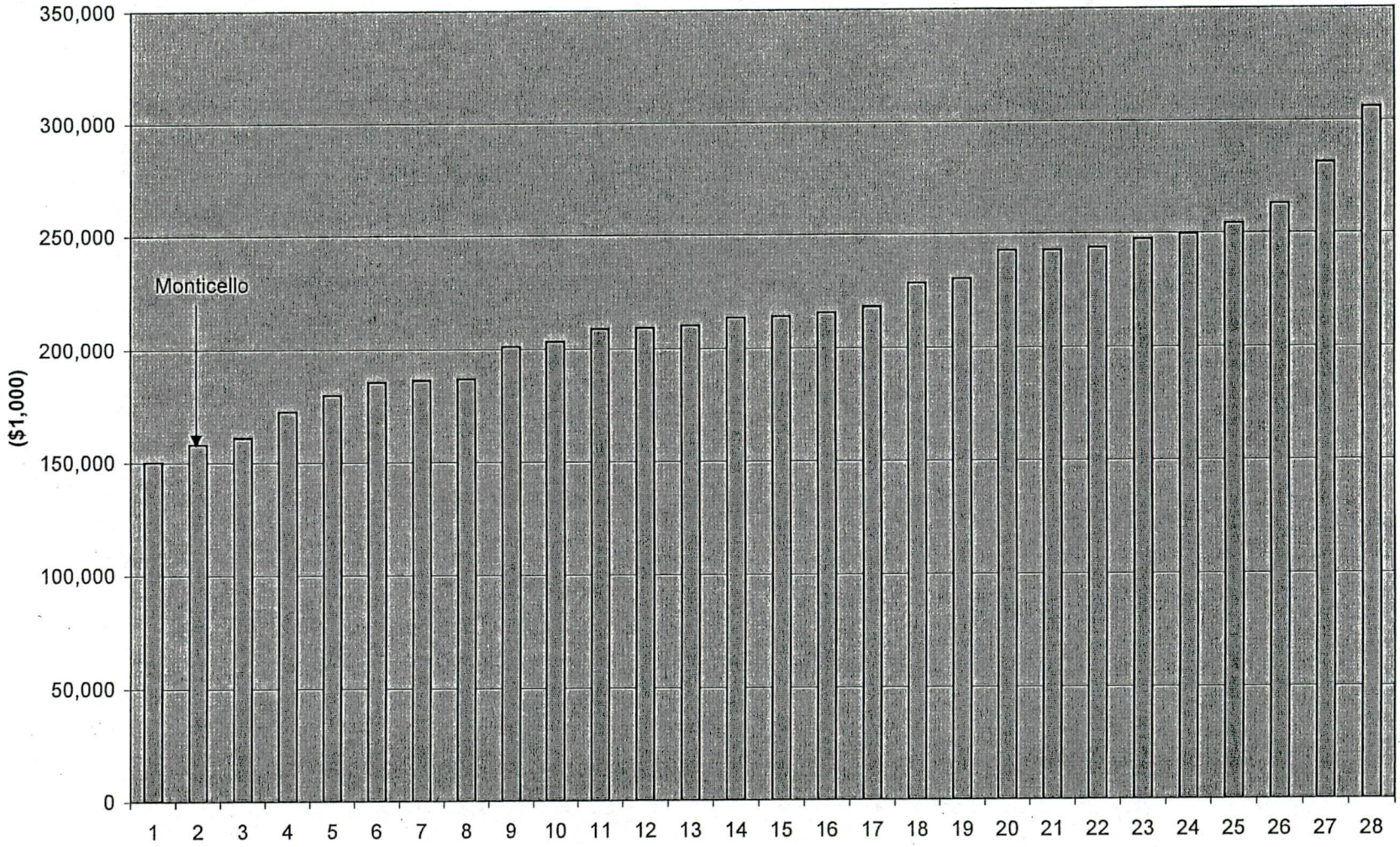
2011 Dual Unit Staffing



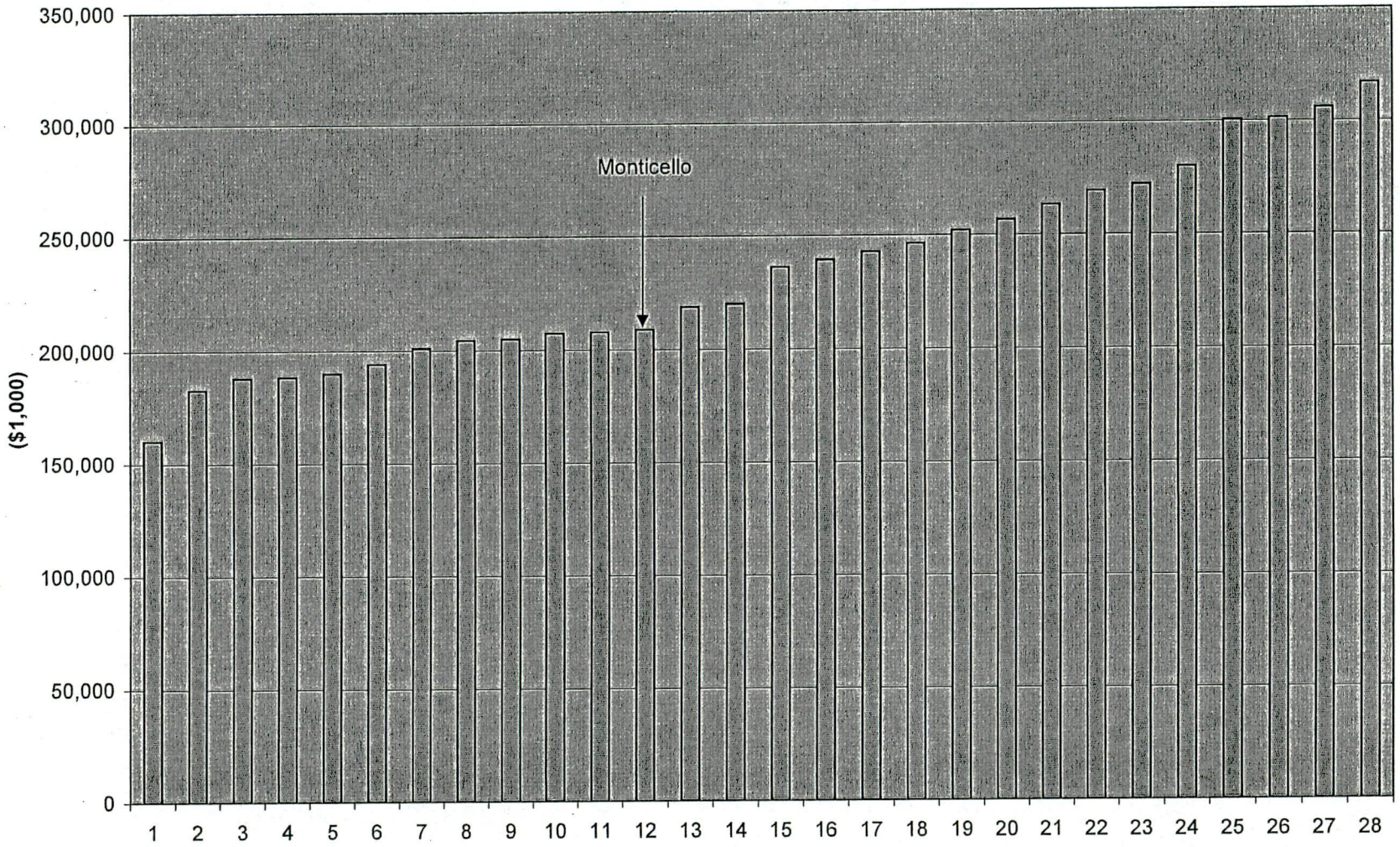
2009 Single Unit Operating Costs



2010 Single Unit Operating Costs

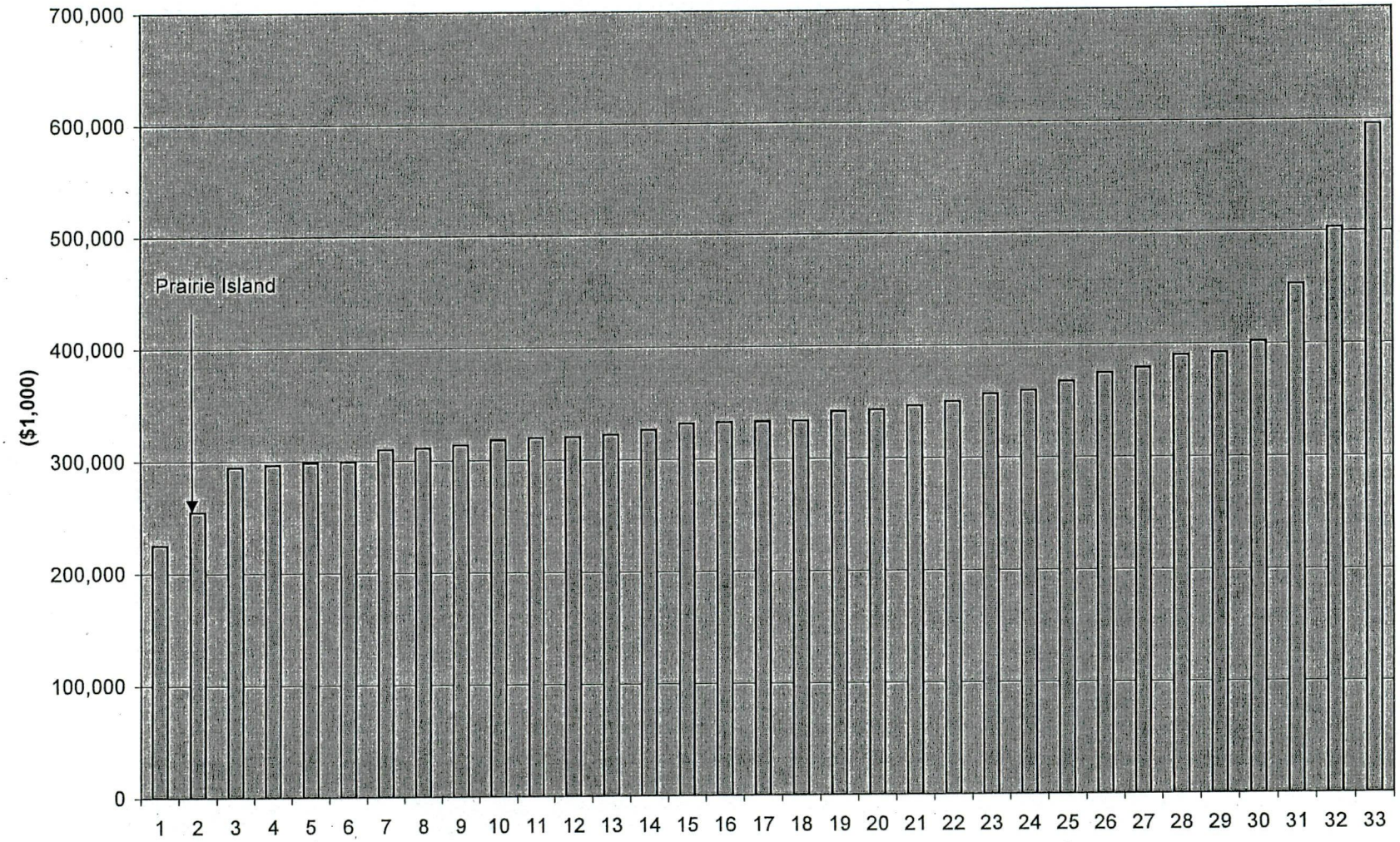


2011 Single Unit Operating Costs



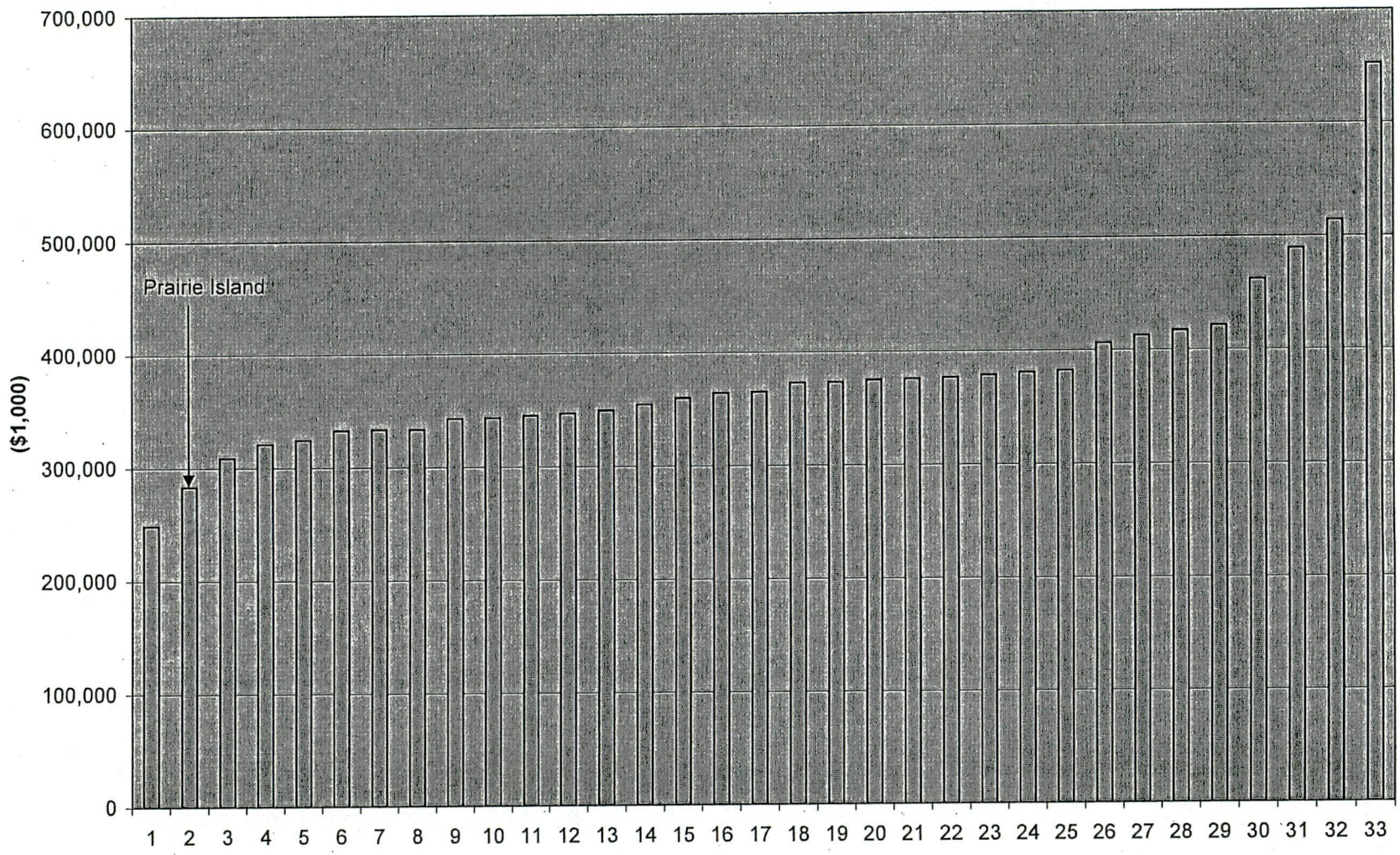
Northern States Power Company
Electric Utility - North Dakota

2009 Dual Unit Operating Costs

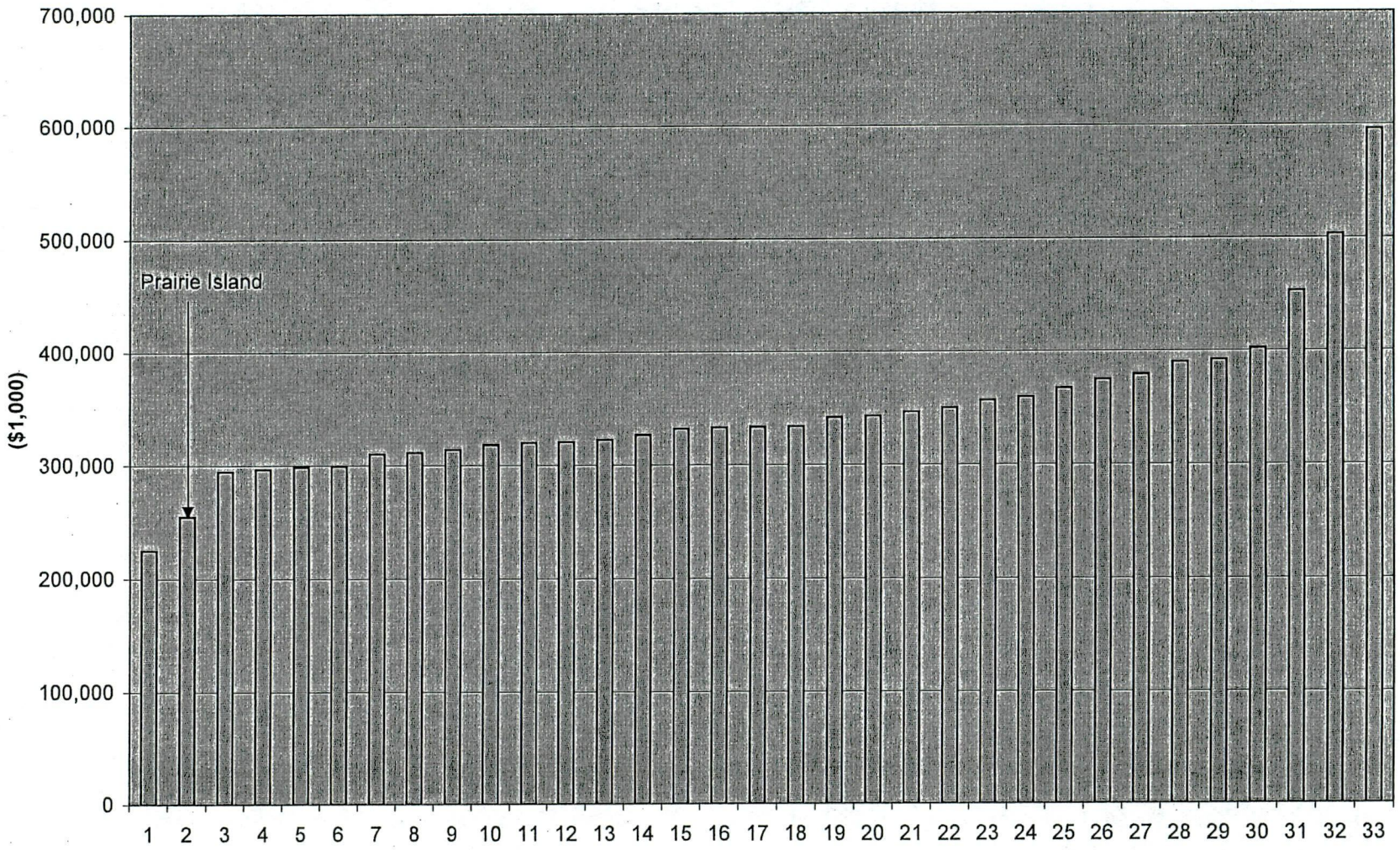


Northern States Power Company
Electric Utility - North Dakota

2010 Dual Unit Operating Costs



2011 Dual Unit Operating Costs



Xcel Energy®

MONTI LCM/EPU COST FORECAST

By Year / w Child WO

October 2012

Parent WO		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
10245258												
10435578	MNGP Extended Power Uprate	796,294	158	6,879,598	11,725,050	69,040,875	14,680,962	48,784,723	(129,606,009)	5,025,118	5,839,310	33,166,080
10859413	MNGP EPU Steam Dryer Acoustic			40,060	3,461,044	1,025,454			2,757,939			7,284,497
10884258	MNGP EPU Certificate of Need					149,871	28,418	(178,289)				
10942850	MNGP EPU-Power Range/Neutron				525,833	2,032,779	9,975,282	(321,824)	5,324,261			17,536,332
10943007	MNGP EPU Main Power Transform				50,770	760,457	10,870,277	3,419,403	11,343,807	46,285		26,491,000
10943047	MNGP EPU GEZIP Installation					20,948	1,147,423	623,758	845,715			2,637,845
10943052	MNGP EPU Condensate Impeller/P					310	842,422	2,651,616	3,379,522	2,703,201	5,755,053	15,332,125
11132414	MNGP EPU Expansion Joints					273,044	4,618,737		2,127,077			7,018,858
11133668	MNGP EPU Turbine Replacement					18,342	37,641,129	(40,574)	16,357,704			53,976,601
11133705	EPU Condensate Demin Sys Repl					6,224	3,035,588	2,176,857	74,117,821	438,084		79,774,573
11133713	EPU CARV Replacement					135,920	8,689,051	623	9,548,855			18,374,449
11133719	EPU FW Heater Drain & Dump Vlv					2,252	3,273,546	4,070	1,426,869			4,706,737
11133731	EPU MS Flow Transmitters Repl						219,505		237,493			456,998
11133856	EPU FW Flow Transmitters/PC In					116	163,395		176,911			340,421
11133861	EPU Isophase Bus Cooling					9,790	2,593,160	7,655	2,827,992			5,438,597
11133865	EPU EQ Transmitters & Detector						585,886		254,759			840,645
11133871	EPU MSIV Solenoid Valve Repl						237,734		103,373			341,107
11133877	EPU Remove DW Bricks in Bioshi					4,795	141,176					145,971
11133931	EPU Drywell Spray Flow Valve R					202	105,864		114,758			220,824
11194611	EPU Off Gas Dilution Fan Cable						439,017	136	190,955			630,108
11213813	EPU 1AR Cable Replacement						180,586	721,787	239,434	(1,141,807)		
11215274	EPU Steam Dryer Replacement						12,974,136	4,864,717	12,437,027	98,937		30,374,817
11225964	EPU Acoustic Monitoring Instr						312,652		135,949			448,601
11257804	MNGP EPU 13.8 KV Distribution						3,725,653	11,979,995	19,596,852	15,722,640	30,114,418	81,139,559
11284286	MNGP EPU Rpl 4 FW Drain & Dum						117,160	685,742	16,757,538	12,027		17,572,466
11286955	MNGP EPU Replace Reactor FW P						87,573	5,660,992	21,788,780	12,111,431	29,923,158	69,571,934
11286961	MNGP EPU Rpl 14&15 A/B FW Hea						117,427	(3,010,772)	33,320,358	(15,043,098)		15,383,914
11286966	MNGP EPU Rewind Generator						11,466	(4,566,954)	11,220,145	(549)		6,664,108
11286973	MNGP EPU Replace Exciter						44,556	14,153	59,688			118,397
11286981	MNGP EPU MSD Tank Mods						48,861	580,361	(664,954)	32,390		(3,341)
11286985	MNGP EPU Stator Water Cooler R						90,948	428,774	1,909,285	1,086		2,430,092
11286992	MNGP EPU RWCU Capacity Impro						201,111	677,809	1,013,508	3,254,068	8,137	5,154,633
11335729	MNGP EPU Turbine Generator Vib							802,970	2,671,806	1,299		3,476,075
11376086	MNGP Drain Cooler Piping Mod P							8,590	(8,590)			
11376103	MNGP Turbine Bldg Elev 951' Rp							11,956	(11,956)			
11398720	E & S for EPU								(375)	11,303		10,927

Xcel Energy®

MONTI LCM/EPU COST FORECAST

By Year / w Child WO

October 2012

Case No. PU-12-___
Exhibit___(TJO-1), Schedule 4
Page 2 of 2

Parent WO		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
11410738	MNGP EPU PCT Vent & Purge Valv							63,977	100,329	1,688	148,202	314,195
11536446	MNGP EPU License Development								50,015,888	5,166,805	5,751,307	60,934,000
11638897	MNGP EPU 13A&B Feed Wtr Heate									18,963,786	19,376,771	38,340,557
9	Checkbook & Other									1,509,411	(24,828,443)	(23,319,032)
10245381												
10735617	MNGP EPU-1AR Transformer Repl		13,599	67,153	(57,755)	78,418	1,508,613	26,613	1,776,338			3,412,979
	TOTAL EPU \ LCM	796,294	13,757	6,986,812	15,704,942	73,559,796	118,709,314	76,078,865	173,886,850	48,914,105	72,087,913	586,738,648

LTD Actuals											
January	260	17,626	7,897	5,457,196	25,972,702	3,961,907	2,878,398	11,100,528	4,964,281		
February	106,374	(17,626)	24,797	706,615	1,412,778	7,657,132	2,431,093	20,320,381	5,162,571		
March	124,978	17	553,953	2,385,364	22,223,964	50,387,058	20,790,380	39,446,626	2,628,377		
April	112,562		20,797	823,070	1,706,811	13,579,611	3,860,168	26,304,443	4,013,999		
May	130,026		96,624	546,356	1,754,854	7,205,156	3,424,716	31,367,108	3,770,100		
June	123,983		61,876	774,377	6,975,612	13,037,594	14,605,805	8,227,358	3,313,396		
July	114,927		2,780	511,544	2,862,630	3,408,368	1,314,231	6,217,688	1,817,566		
August	24,615		12,003	1,081,623	1,487,316	4,638,515	4,469,562	12,076,683	2,947,125		
September	(5,614)	3,040	5,473,039	935,383	2,015,811	7,279,371	7,447,912	8,031,789	4,260,191		
October	78,359	(2,899)	199,669	737,517	2,521,258	5,880,744	2,880,397	4,819,211	4,436,197		
November	29	286	290,286	775,975	2,454,154	1,473,455	6,066,671	2,489,858			
December	(14,204)	13,313	243,091	969,921	2,171,906	200,404	5,909,531	3,485,176			
TOTAL EPU \ LCM	796,294	13,757	6,986,812	15,704,942	73,559,796	118,709,314	76,078,865	173,886,850	37,313,804		503,050,434
Life to Date		810,052	7,796,863	23,501,805	97,061,602	215,770,916	291,849,780	465,736,630	503,050,434		

Table 1 - Summarizes calendar year outage costs.

Calendar Year Nuclear Outage Related O&M Costs – Spend ($ in millions)

	2011 Actual Costs	Test Year Budgeted Costs	Increase From 2011 Actual to Test Year Budget	% Change 2011 to Test Year	Average % Change Per Year
Outage Costs (Spend)					
Labor	$26.6	$26.9	$0.3	1.1%	5.5%
Contractors & Consultants	33.7	55.7	22.0	65%	33%
Materials	6.4	8.4	2.0	30%	15%
Other	0.6	0.9	0.3	33%	16%
Total Outage Costs (Spend)	$67.3	$91.9	$24.6	36.6%	18.3%

Table 2- Identifies the actual costs of the outages and what portion of those outages' expense is included in the test year. Due to timing of the spend, the total outage costs in Table 2 differ from Table 1.

Total Outage Costs by Outage ($ in millions)

Unit/Year	PI Unit 2/ Spring 2012	PI Unit 1/ Fall 2012	PI Unit 2/ Fall 2013	MT/ 2011	MT/ 2013	Total
Total Cost for Outage (spend)	$42.9	$37.4	$44.0	$43.7	$52.6	
Portion included in 2013 Outage Amortization Expense	$23.8	$20.4	$5.0	$7.0	$18.3	$74.5

Table 3 - Shows the test-year outage costs calculated consistent with the deferral and amortization process discussed by Company witness Ms. Anne E. Heuer.

Amortized Outage-Related Nuclear O&M Costs – Net ($ in millions)

	2011 Actual Costs	Test Year Budgeted Costs	Increase From 2011 Actual to Test Year Budget	% Change 2011 to Test Year	Average % Change Per Year
Total Nuclear Outage Costs for Year (Spend)	$67.3	$91.9	$24.6	36.6%	18.3%
Deferral of Current Year Outage Costs	(68.0)[1]	(91.9)	(23.9)	35%	17.5%
Outage Amortization	59.8	74.5	14.7	24.1%	12.0%
Net Outage-Related Nuclear Costs for Year	$59.1	$74.5	$15.4	26.1%	13.0%

[1] Outage cost deferrals include $0.7 million incurred in other business areas in 2011.

2012 ND Electric Rate Case - Nuclear Generation
Adjustments to 2013 O&M Expense Budget
Without 10/1/12 Merit Increase

	Initital 2013 Budget - Total Nuclear	RATE CASE ADJUSTMENTS (1) Top Level Adjs to O&M	(2) Top Level Adj Retention	(3) Top Level Adj 2012 Outage	Revised 2013 Budget - Total Nuclear
Non-Outage Costs					
Site Costs					
Internal Labor (including overtime and other premiums)	$ 130,227,461	$ -	$ 1,383,042		$ 131,610,503
Contractor, Consulting	$ 26,340,658	$ 5,674,000			$ 32,014,658
Materials	$ 15,028,888	$ 1,775,000			$ 16,803,888
Employee Expenses	$ 4,206,162				$ 4,206,162
Other	$ 5,939,274				$ 5,939,274
Total Controllable Non-Outage Costs	$ 181,742,443	$ 7,449,000	$ 1,383,042	$ -	$ 190,574,485
Non-Site Costs					
Nuclear Fees	$ 33,082,913	$ 1,500,000			$ 34,582,913
Security - G4S contractor	$ 26,511,501	$ 700,000			$ 27,211,501
Total Discretionary Non-Outage Costs	$ 59,594,414	$ 2,200,000	$ -	$ -	$ 61,794,414
Total Non-Outage Costs	**$ 241,336,857**	**$ 9,649,000**	**$ 1,383,042**	**$ -**	**$ 252,368,899**
Outage Costs - Spend					
Monticello outage costs	$ 49,423,305				$ 49,423,305
Prairie Island outage costs	$ 42,435,062				$ 42,435,062
Subtotal - Total Nuclear Generation O&M Spend	**$ 333,195,224**	**$ 9,649,000**	**$ 1,383,042**	**$ -**	**$ 344,227,266**
Outage Costs - Net					
Nuclear Generation Outage Spend (per above)	$ 91,858,367				$ 91,858,367
Deferral & Amortization Adjustment:	$ (19,381,736)			$ 2,009,472	$ (17,372,264)
Outage Costs - Net of Deferral/Amortization	**$ 72,476,631**	**$ -**	**$ -**	**$ 2,009,472**	**$ 74,486,103**
Total Nuclear O&M - Non-Outage & Outage- net	**$ 313,813,488**	**$ 9,649,000**	**$ 1,383,042**	**$ 2,009,472**	**$ 326,855,002**

Adjustments to Non-outage	$ 11,032,042
Adjustments to Outage	$ 2,009,472
Total Budget Adjustments Reflected in Rate Case	$ 13,041,514

Notes on Adjustments

(1) Updates to initial budget assumptions in June 2012 increased Nuclear O&M budget by $9.65 million, related to:

Design calculation reconstitution project in response to NRC/INPO issues	$ 1,600,000
Higher estimate for regulatory fees	$ 1,500,000
Overhaul & other work needed on diesel engines	$ 1,500,000
Additional contract engineering support - AC/DC analysis & technical issues	$ 1,344,000
Overhaul/repair of plant water/intake screens and cooling water pump	$ 975,000
Revised estimate of Security costs for contract under negotiations	$ 700,000
Updated esimate of Fukushima program costs chargeable to O&M	$ 600,000
Emergent regulatory compliance work related to NRC/INPO inspections	$ 600,000
Contractors and materials for buried piping and other new projects	$ 580,000
Higher than expected radiological waste disposal costs	$ 250,000
Total O&M adjustments	$ 9,649,000

(2) Additional compensation costs related to management retention program introduced in October 2012. Amount is 2013 amortization of multi-year program.

(3) This is 2013 amortization impact of $3.7 million cost increase for fall 2012 Prairie Island outage. Scope changes identified in October 2012 increased the outage length from 35 to 45 days, due to:

Spent Fuel Pool Heat Exchanger temporary Modification for fuel pool cooling	$ 1,200,000
Containment Integrated Leak Rate Test (required by NRC)	$ 938,000
Radioactive waste storage tank inspection	$ 909,000
Steam Generator eddy current testing	$ 313,000
Train Specific Integrated Testing	$ 200,000
Head Vent Modification Capital Project	$ 120,000
Total increase in fall 2012 outage costs	$ 3,680,000
2013 amortization impact	$ 2,009,472