

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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1 **I. INTRODUCTION AND QUALIFICATIONS**

2  
3 Q. PLEASE STATE YOUR NAME AND OCCUPATION.

4 A. My name is Timothy J. O'Connor. I am the acting Chief Nuclear Officer for  
5 Northern States Power Company (Xcel Energy or Company). I am  
6 responsible for all nuclear activities at the Monticello and Prairie Island plants.  
7

8 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

9 A. I have more than 30 years experience in the nuclear industry, including a  
10 diverse background in operations, maintenance and engineering at both  
11 boiling and pressurized water reactors. Before joining Xcel Energy in 2007, I  
12 held a number of positions with increasing responsibility at Constellation  
13 Energy Group's Nine Mile Point station in New York, Public Service  
14 Enterprise Group's (PSEG) Hope Creek and Salem plants, and Exelon's  
15 LaSalle, Dresden and Zion plants. My education and experience are detailed  
16 in Exhibit\_\_(TJO-1), Schedule 1.  
17

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

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

- 21 • We continue to implement extensive capital and O&M investments in  
22 our nuclear plants which is necessary to maintain these safe, reliable,  
23 and carbon-free facilities;
- 24 • We have taken steps to control expenses; and
- 25 • The nuclear industry is facing significant future challenges in terms of  
26 labor and increasing compliance requirements.  
27

1                   **II. KEY NUCLEAR FUNCTIONS AND ACTIVITIES**

2  
3    Q. PLEASE DESCRIBE XCEL ENERGY’S CORE NUCLEAR OPERATIONS.

4    A. Xcel Energy owns and operates three nuclear units: one unit at Monticello,  
5       Minnesota and two units at Prairie Island in Welch, Minnesota. Monticello is  
6       a single-unit 585-megawatt boiling water reactor and was originally licensed by  
7       the Nuclear Regulatory Commission (“NRC”) in 1970. The initial license was  
8       scheduled to expire in 2010. In 2006, the NRC approved a renewed license  
9       for Monticello, extending its operating life until 2030. In September 2006, the  
10       Minnesota Public Utilities Commission (MPUC) approved the use of dry  
11       spent-fuel storage at Monticello to provide the spent-fuel storage capacity to  
12       operate until 2030. Additionally, in January 2009, the MPUC approved Xcel  
13       Energy’s application to implement an extended power uprate at the plant.

14  
15       Prairie Island is a two-unit pressurized water reactor, with each unit rated at  
16       550 MW. The NRC licensed Prairie Island’s two units in 1973 and 1974,  
17       respectively. The initial operating licenses were set to expire in 2013 and 2014.  
18       In 2011, the NRC approved renewed licenses for Prairie Island Units 1 and 2,  
19       extending their operating lives until 2033 and 2034, respectively. In December  
20       2009, the MPUC approved the expanded use of dry spent-fuel storage at  
21       Prairie Island to provide the spent-fuel storage capacity to operate until  
22       2033/34. Additionally, in December 2009, the MPUC approved our  
23       application to implement an extended power uprate at the plant.

24  
25       Monticello and Prairie Island continue to be two of Xcel Energy’s most  
26       reliable baseload electric generation assets, providing approximately 29 percent  
27       of the electricity to NSP’s system. These plants are part of a diverse operating

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

5  
6 Q. PLEASE DESCRIBE THE TOP PRIORITIES OF THE NUCLEAR ORGANIZATION.

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

12  
13 Another top priority relates to recent events. As the Commission is well  
14 aware, the disaster at the Fukushima Daiichi plant in Japan occurred in March  
15 2011. Since that disaster occurred, the NRC has been engaged in an extensive  
16 review of current operating conditions and guidelines for our nation's nuclear  
17 facilities. We expect to continue these efforts throughout 2013 and beyond.

18  
19 Q. WHAT ARE THE PRIMARY CHALLENGES YOU ARE FACING IN NUCLEAR  
20 OPERATIONS?

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

1 Q. PLEASE DESCRIBE THE BENEFITS OF THE COMPANY’S INVESTMENTS IN ITS  
2 NUCLEAR OPERATIONS.

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

6  
7 For example, investments in the Monticello Life Cycle Management and  
8 Extended Power Uprate (LCM/EPU) project improve off-site power and  
9 stability of power to the plant, which increases safety and reliability of the  
10 plant for production. These improvements also utilize updated technology not  
11 available when the plants went into service, further enhancing our operating  
12 characteristics for our employees and our communities.

13  
14 **III. SUMMARY OF REQUEST**

15  
16 Q. PLEASE PROVIDE A SUMMARY OF THE COSTS INCLUDED IN THE TEST YEAR.

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

22  
23  
24

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<sup>1</sup> 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.

1

**Table 1 - Test Year Capital Costs**

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

2

3

4

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7

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.

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15

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.

16

17

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20

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,

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

3 **Table 2 - Nuclear O&M Costs**

	<b>Test Year Budgeted Costs<sup>2</sup> (\$M)</b>
<b>Non-Outage O&amp;M Costs</b>	
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
<i>Total Non-Outage O&amp;M</i>	<i>\$ 252.4</i>
	<b>Test Year Budgeted Costs<sup>3</sup> (\$M)</b>
<b>Outage O&amp;M Costs</b>	
Total Nuclear Outage Costs for Year (Spend)	\$ 91.9
Deferral of Current Year Outage Costs	(91.9)
Outage Amortization	74.5
<i>Net Outage-Related Nuclear Costs for Year</i>	<i>\$ 74.5</i>
<b>Total 2013 Nuclear O&amp;M Costs</b>	<b>\$ 326.9</b>

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<sup>2</sup> Includes post-budget adjustments of \$11 million as summarized on Schedule 6.

<sup>3</sup> Includes post-budget adjustments of \$2 million as summarized on Schedule 6.

1 **IV. COST CONTROLS**

2  
3 Q. PLEASE DESCRIBE THE COMPANY’S EFFORTS TO CONTROL COSTS.

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

16  
17 Q. HAS THE COMPANY INITIATED ANY OTHER COST CONTROL PROGRAMS?

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

22  
23 In addition, we seek to take advantage of economies of scale. For example,  
24 Xcel Energy works with owners of other nuclear facilities to share the costs of  
25 resolving common issues. The Company is currently a member of several  
26 industry groups, where we work with our industry partners to proactively  
27 identify potential issues, investigate whether our facilities may experience

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

6  
7 Q. PLEASE EXPLAIN THE WORK DONE WITH OTHER LICENSEES TO KEEP COSTS  
8 LOW.

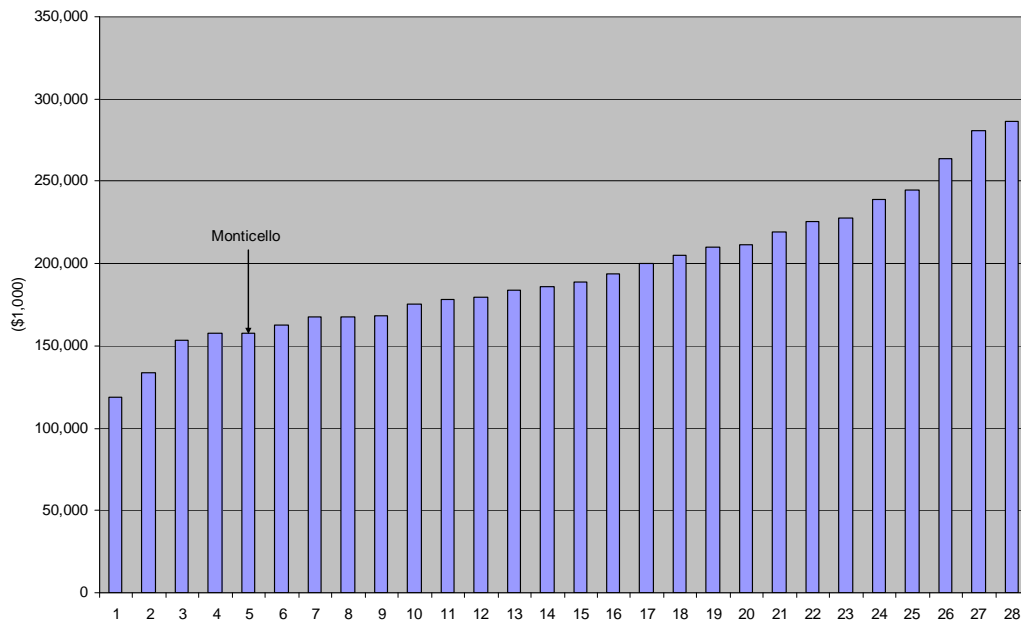
9 A. We work collaboratively with our industry partners to take advantage of  
10 economies of scale and knowledge of industry trends to keep costs low. An  
11 example of this effort is our participation in USA Alliance, a conglomeration  
12 of 10 nuclear plants that purchase materials and equipment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

18  
19 Q. ARE THERE ANY OTHER INITIATIVES THE COMPANY HAS TAKEN THAT HAVE  
20 RESULTED IN SAVINGS?

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

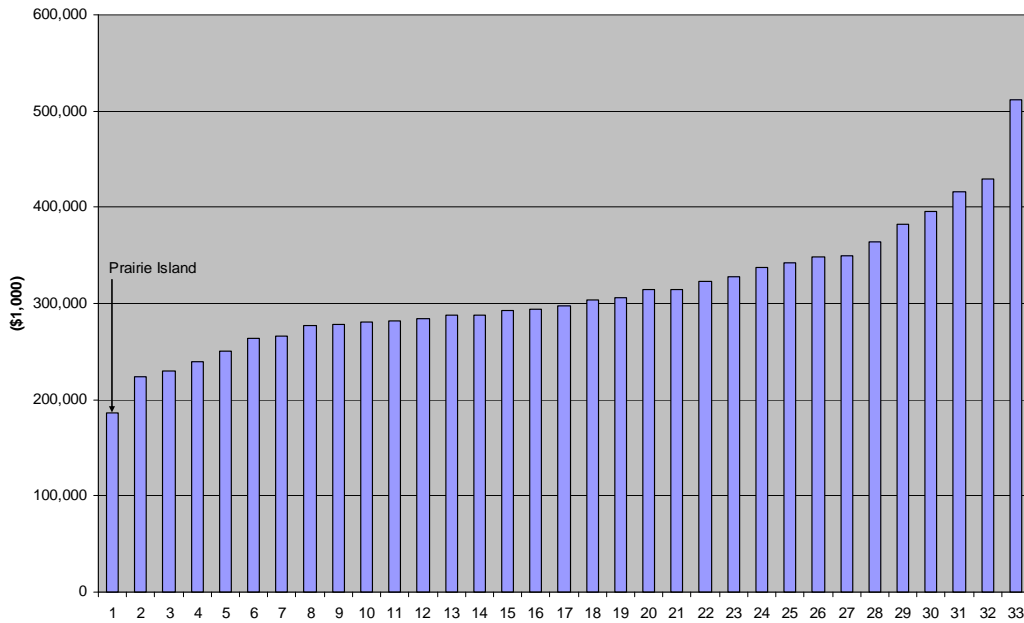
1 Q. EVEN WITH THE COST INCREASES PROJECTED IN THE TEST YEAR, ARE THE  
 2 COSTS OF OPERATING THE COMPANY’S NUCLEAR PLANTS STILL REASONABLE?  
 3 A. Yes. Our plants remain comparable to other operating units in the nation.  
 4 We have attempted to evaluate our proposed budgets with our best estimate  
 5 of industry costs in the test year. Applying a conservative annual escalation  
 6 factor of 3.0 percent per year to 2011 Electric Utilities Cost Group (EUCG)  
 7 U.S. nuclear plant cost data, we compared the test year operating budgets for  
 8 Monticello and Prairie Island with the remainder of the industry (see Figures 1  
 9 and 2 below). This comparative data continues to show that Monticello and  
 10 Prairie Island are operating at a reasonable cost.  
 11

Figure 1 - 2013 Single Unit Operating Costs



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Figure 2 - 2013 Dual Unit Operating Costs



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- 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.

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

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

5

6 **A. Strategic Major Investments**

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

9 A. The test year budget for capital expenditures on the Company's strategic  
10 major projects at its nuclear facilities includes the following as shown in Table  
11 3 below:

12 **Table 3 Strategic Major Investments**

13 <u>Capital Cost (Millions)</u>	<u>Prairie Island</u>	<u>Monticello</u>
14 Life cycle management and power uprates	\$ 86	\$ 72
15 Steam generator replacement	<u>156</u>	<u>--</u>
16 Total 2013 strategic/major projects	<u>\$ 242</u>	<u>\$ 72</u>

17

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

19

20 *1. Monticello*

21 *a. Life Cycle Management and Extended Power Uprate*

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

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

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

3  
4 Q. PLEASE PROVIDE AN UPDATE ON THE MONTICELLO LCM/EPU PROJECT  
5 FROM THE LAST RATE CASE.

6 A. At the conclusion of our last rate case, the amended license and completion of  
7 the LCM/EPU project at Monticello was anticipated to occur in the Fall of  
8 2012. The implementation schedule has changed since that time because of  
9 the delay in the NRC's review of our license amendment application and the  
10 need to rework equipment that failed to meet performance specifications.

11  
12 The equipment performance issues have now been resolved and the  
13 equipment is expected to be delivered in time to be installed during the 2013  
14 outage. However, the NRC's review is still in process and we now expect to  
15 complete the license proceeding in 2013.

16  
17 Q. PLEASE DESCRIBE THE WORK REMAINING TO BE COMPLETED AS PART OF THE  
18 LCM/EPU PROJECT.

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

- 22 • *13.8 kV system.* This project includes the replacement and upgrade  
23 of the existing electric distribution system, including switchgear,  
24 controls, relaying and associated cable to the major station loads of  
25 the reactor feedwater pumps, the condensate pumps and the reactor  
26 recirculation pumps. This project also include the replacement of  
27 the reactor recirculation MG set drive motors and replacement of

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

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

1 the steam provided to the feedwater heater. The increased steam  
2 flow to the feedwater heaters will improve the system's efficiency  
3 and improve safety margins.  
4

5 In comparison to about 700 to 1200 employees for a typical refueling outage,  
6 we expect to have approximately 2,500 personnel on site during the Spring  
7 2013 outage at Monticello to assist with the completion of the LCM/EPU  
8 project.  
9

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

11 A. The current total project budget approved by the Xcel Energy Inc. Board of  
12 Directors last December is \$587 million. The Company has spent  
13 approximately \$503 million on the project as of October 31, 2012. See  
14 Exhibit\_\_\_ (TJO-1), Schedule 4 outlining the costs incurred and forecast for  
15 this project by year.  
16

17 This summer we reviewed an updated estimate of costs from our vendor,  
18 Bechtel, based on their completion of detailed work packages for EPU  
19 activities to be completed during next spring's outage. Bechtel's estimate,  
20 which included an increase in contingency costs, came in above the amounts  
21 included in the \$587 million budget approved by the Board. We are working  
22 with Bechtel to minimize their cost increases for the project, but recognize  
23 that final costs will exceed the budget established prior to the completion of  
24 the detailed work packages by Bechtel.  
25

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

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

6  
7 Q. HOW DID THE COMPANY DEVELOP ITS FINAL ESTIMATE?

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

12  
13 As we moved forward with implementation of the project, we designed our  
14 project to comply with existing regulatory requirements. During the course of  
15 the NRC's review of our license amendment request, their acceptance criteria  
16 for several areas changed, including, for example, requirements for steam  
17 dryers and analysis of line breaks in high-energy systems (such as feedwater).  
18 During the 2011 outage, we considered such analysis and determined that the  
19 prior design was not going to meet the new requirements. Consequently, we  
20 revised the designs to accommodate the new requirements, which resulted in  
21 updated cost estimates. In addition, our initial estimates were based on a  
22 detailed review of the plant, but the actual condition of the systems and need  
23 for upgrades could not be fully known until we moved into implementation  
24 when the plant was offline. We were then able to take a closer look at the  
25 existing systems and perform more detailed engineering and work package  
26 planning.

27

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

6  
7 Q. PLEASE DESCRIBE THE PRIMARY COST INCREASES FROM THE START OF THE  
8 PROJECT UNTIL TODAY.

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

16  
17 *Steam Dryer*

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

27

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

6  
7 *13.8 kV Distribution System*

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

12  
13 The 13.8 kV electrical distribution system upgrade supports both EPU and  
14 LCM. Upgrading the existing 4 kV system to a 13.8 kV system is necessary to  
15 support the additional load created by the larger feedwater pumps and motors.  
16 However, the existing 4 kV system would have needed to be replaced during  
17 the remaining life of the plant. The cost difference between replacing the  
18 existing 4 kV system and the installation of the 13.8 kV system is estimated at  
19 less than one percent.

20  
21 More importantly, the upgrade to 13.8 kV provides more safety margin at the  
22 plant by allowing separation of large loads in loss of power scenarios and  
23 more versatility for transient situations. The upgrade provides strategic safety  
24 benefits in light of emerging Fukushima requirements.

25  
26 The primary cost increases for this project were largely the result of design  
27 issues encountered during project implementation. The final cost estimate is

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

5  
6 *Replacement of Reactor Feedwater Pumps and Related Equipment*

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

16  
17 After the initial estimate was developed, the project team determined the  
18 existing feedwater pumps should be replaced with larger capacity pumps,  
19 which increased both equipment costs and required additional modifications  
20 related to equipment and supporting systems. These related modifications  
21 included a change-out of the level transmitters at all four heaters, foundation  
22 modifications, and additional welds. Although the replacement of the pumps  
23 and equipment increased the costs of the project, these modifications are  
24 expected to save costs in the long term since all of the pumps would ultimately  
25 need to be replaced during the remaining life of the plant. Further, this  
26 combination of pumps and equipment allows plant operators to more

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

3  
4 By making these investments early, we benefit from the increased safety  
5 margins and operational efficiencies for the entire remaining life of the facility.  
6 The total cost of this work is approximately \$103.9 million, before common  
7 cost allocations.

### 8 9 *Condensate Systems*

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

15  
16 The modification to the condensate systems includes several items that were  
17 added to the scope of the project after the initial estimate was developed.  
18 These additions were largely the result of not being able to access the critical  
19 areas until the plant was offline.

20  
21 Accordingly, subsequent to the initial estimate, we determined existing wiring  
22 should be replaced at the time of implementation, and more tubing and  
23 supports should be included. However, because these pumps and related  
24 equipment would need to be replaced during the remaining life of the plant, it  
25 made sense to finish the work with the LCM/EPU implementation. Earlier  
26 implementation adds to plant reliability and safety margins and is expected to

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

3  
4 Q. WILL ALL OF THE MONTICELLO LCM/EPU PROJECTS PLACED INTO SERVICE  
5 BE USED AND USEFUL IN THE TEST YEAR?

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

13  
14 2. *Prairie Island*

15 a. Life Cycle Management and Extended Power Uprate

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

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

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<sup>4</sup> Docket No. E002/CN-08-509.

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

6  
7 Q. ARE THERE MAJOR CAPITAL PROJECTS AT PRAIRIE ISLAND IN THE TEST YEAR  
8 THAT ARE SEPARATE FROM THE EPU?

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

12  
13 Q. IS THE LCM PROJECT INTEGRATED WITH THE EPU PROJECT AT PRAIRIE  
14 ISLAND?

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

20  
21 However, now that we foresee likely delays in how soon the EPU activities  
22 can be done at Prairie Island pending regulatory reviews and approvals, or  
23 even termination of the EPU project, we believe we must move forward with  
24 LCM activities in order to properly upgrade and update plant equipment to  
25 support extended operation through 2033-2034. Consequently, we have  
26 scheduled some LCM work to proceed at Prairie Island while the status of the  
27 EPU project is pending regulatory review.

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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.

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

3  
4 **B. Dry Cask Storage**

5 Q. PLEASE DESCRIBE THE DRY CASK STORAGE CAPITAL PROJECTS.

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

9  
10 Q. ARE THERE ANY DRY CASK STORAGE PROJECT COSTS INCLUDED IN THE TEST  
11 YEAR FOR MONTICELLO?

12 A. Yes. On October 23, 2006, the MPUC granted a Certificate of Need for up to  
13 30 additional dry casks to store spent nuclear fuel on-site in an independent  
14 spent-fuel storage installation to support an additional 20 years of operation at  
15 Monticello. Ten storage canisters were loaded in 2008, an additional 10  
16 canisters will be loaded in 2013, and the last 10 canisters will be loaded in  
17 2016. The Company will make significant investments related to the  
18 additional dry-cask storage, and the 10 canisters loaded in 2013 will be placed  
19 into service in 2013. The total additions included in the test year related to  
20 this installation are \$36.9 million.

21  
22 Q. ARE THERE ANY DRY CASK STORAGE PROJECT COSTS INCLUDED IN THE TEST  
23 YEAR FOR PRAIRIE ISLAND?

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

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

4  
5 **C. Mandated Compliance**

6 Q. PLEASE DESCRIBE THE MANDATED COMPLIANCE CAPITAL PROJECTS.

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

11  
12 **Table 4 - Compliance Projects**

13 <u>Capital Cost (Millions)</u>	<u>Prairie Island</u>	<u>Monticello</u>
14 License Renewal Requirements	\$11.0	\$ --
15 Fire Protection	\$ 7.3	\$ 1.0
16 Fukushima external events	\$ 3.0	\$ 3.2
17 Cyber Security	\$ --	\$ 1.6
18 Other	<u>\$ 1.2</u>	<u>\$ 0.2</u>
19 Total Mandated Compliance	\$ 22.5	\$ 6.0

20  
21 Q. WHAT IS THE STATUS OF THE LICENSE RENEWAL FOR PRAIRIE ISLAND?

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

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

3  
4 Q. DO YOU ANTICIPATE COMPLIANCE COSTS TO CONTINUE TO RISE?

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

9  
10 Q. WHAT ARE SOME OF THE KEY COMPLIANCE-RELATED PROGRAMS AFFECTING  
11 THE COMPANY'S COSTS SINCE THE LAST RATE CASE?

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

15  
16 In addition, in response to the 2011 incident in Fukushima, Japan, the NRC  
17 has issued information requests under 10 CFR 50.54(f) and the industry as a  
18 whole is responding. Most of the responses and compliance costs at this time  
19 are related to re-analyzing existing data and conducting new analyses with  
20 information not previously available.

21  
22 **D. Reliability, Improvement and Facilities Expenditures**

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

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

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

5  
6 Q. HAVE THERE BEEN ANY CHANGES TO THE FUEL BUDGET?

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

11  
12 **VI. TEST YEAR NUCLEAR O&M COSTS**

13  
14 Q. HOW IS YOUR TESTIMONY DISCUSSING THE TEST YEAR NUCLEAR O&M COSTS  
15 ORGANIZED?

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

21  
22 **A. Non-Outage Costs**

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

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

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

5  
6 Q. PLEASE PROVIDE A SUMMARY OF 2011 ACTUAL NON-OUTAGE O&M COSTS  
7 COMPARED TO THE 2013 BUDGETED COSTS.

8 A. As shown in Table 5, non-outage O&M costs are projected to increase  
9 approximately \$9.6 million from 2011 to the test year. This increase is due to  
10 a projected increase in non-outage site costs of \$3.4 million and a projected  
11 increase in non-site costs of \$6.2 million. Total O&M costs in the test year  
12 include post-budget adjustments of \$11.0 million, as summarized on Schedule  
13 6 and as discussed in Ms. Heuer's Direct Testimony.

14  
15 I will discuss each of these O&M categories in Table 5 in more detail.  
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**Table 5**

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

	2011 Actual Costs (\$M)	Test Year Budgeted Costs <sup>5</sup> (\$M)	Increase From 2011 Actual to Test Year Budget (\$M)	% Change 2011 to Test Year	Average % Change Per Year
<u>Non-outage Site Costs</u>					
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%
<u>Non-Site Costs</u>					
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%

3

4 *1. Site Costs*

4

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

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

9

10 a. Labor Costs

10

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

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

15

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<sup>5</sup> Includes post-budget adjustments of \$11 million as summarized on Schedule 6 and as discussed in Company witness Ms. Heuer’s Direct Testimony.

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

6  
7 Q. DO YOU SEE ANY CHALLENGES TO CONTROLLING FUTURE LABOR COSTS  
8 BEYOND THE TEST YEAR?

9 A. Yes. The nuclear energy industry is facing increased competition for  
10 experienced workers, which will contribute to a shortage of specialized and  
11 skilled labor. An analysis of Xcel Energy's non-bargaining nuclear employees  
12 shows that 15.6 percent are eligible to retire in 2012, increasing to 31.4 percent  
13 eligible to retire before 2018. For our bargaining unit employees, 11.8 percent  
14 are eligible to retire in 2012, increasing to 25.4 percent eligible to retire before  
15 2018. In addition, the NRC's issuance of a new reactor license will further  
16 contribute to the competition for skilled nuclear workers.

17  
18 We have developed a plan for recruiting and retaining the qualified work force  
19 that is needed to continue safe, reliable, and efficient electricity production at  
20 our sites. However, these are highly-skilled positions that can be difficult to  
21 fill. The recent departure of our Chief Nuclear Officer illustrates the mobility  
22 available to these employees. One new program we developed to help retain  
23 these valuable nuclear employees is a long term retention program initiated  
24 this year. The revenue requirement associated with this program is addressed  
25 further in Ms. Heuer's Direct Testimony.

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

13  
14 b. Materials Costs

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

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

24  
25 c. Employee and Other Expenses

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

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

7  
8 Other expenses are increasing about \$1.1 million (23 percent) in the test year  
9 compared to 2011 actuals, mainly due to increased software maintenance and  
10 license costs. Continuing investments in software for nuclear engineering,  
11 security, analysis and reporting are resulting in higher ongoing costs to  
12 maintain updated versions and valid licenses for the software.

13  
14 *2. Non-Site Costs*

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

16 A. As shown in Table 5, total non-site costs included in the test year forecast  
17 were \$62.0 million. Non-site costs are increasing approximately \$6.2 million  
18 (11.0 percent) from 2011 actual costs to the test year budget, an average  
19 increase of 5.5 percent per year. Both types of non-site costs, regulatory fees  
20 and security, have experienced significant increases due to external  
21 requirements beyond our control.

22  
23 *a. Fees*

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

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

4  
 5 **Table 6 Nuclear-Related Fees**

Fee Type / Organization	2011 Actual Costs (\$M)	Test Year Budgeted Costs <sup>6</sup> (\$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%
<b>Total Fees</b>	<b>\$30.9</b>	<b>\$34.8</b>	<b>\$3.9</b>	<b>12.5%</b>	<b>6.3%</b>

6  
 7 Q. HOW ARE THE AMOUNTS OF THE NRC FEES DETERMINED?

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

15  
 \_\_\_\_\_  
<sup>6</sup> 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.

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

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

11

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

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

16

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

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

26

27

1                   b. Security

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

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

9  
10 **B. Outage Costs**

11 Q. PLEASE DESCRIBE HOW OUTAGE COSTS ARE BUDGETED.

12 A. The first step in developing the refueling outage budgeted costs is to define  
13 the scope of the outage. The scope of a refueling outage includes both  
14 routine activities (the activities completed during every refueling outage),  
15 periodic activities (activities that occur on a defined schedule but not  
16 necessarily every refueling outage), and other one-time or special activities.  
17 Initial cost estimates for completion of the work are based on historical  
18 estimates adjusted for labor or material cost changes that are known.  
19 Activities in the refueling outage scope are controlled under our work order  
20 process. A work order will define the work to be completed, the resource  
21 (internal or contract) responsible to complete the work, and the materials  
22 needed to support the work. Updated information on labor and material costs  
23 are incorporated as the work order progresses through the planning process  
24 leading up to the actual refueling outage.

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

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

7

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

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

16

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

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

26

27

1           1.    *Monticello*

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

13  
14           2.    *Prairie Island Unit 1*

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

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

4  
5 *3. Prairie Island Unit 2*

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

8  
9 The 2012 Spring refueling outage was focused on: refueling and routine  
10 maintenance and capital work items, including but not limited to replacing  
11 safety related battery chargers; auxiliary reserve transformer maintenance;  
12 completion of license renewal inspections that were committed to the NRC  
13 prior to the end of the initial license expirations in 2014; preventative  
14 maintenance on electrical relays and breakers; replacement of equipment that  
15 is required by NRC to be Environmentally Qualified; and the Local Leak Rate  
16 Testing program.

17  
18 The Fall 2013 refueling outage is longer than a normal refueling outage, as  
19 certain capital modifications are addressed in tandem with the O&M aspect of  
20 the outage. In 2013, the capital modifications are related to replacing Unit 2's  
21 two steam generators to support 20 years of extended operation described in  
22 my testimony. The outage work not related to the steam generators  
23 replacement will be routine refueling outage work.

24  
25 Q. YOU INDICATE THAT THE IMPLEMENTATION OF THE LCM/EPU PROJECT AT  
26 MONTICELLO WILL INCREASE THE NON-LCM/EPU PROJECT COSTS. IS THE  
27 COMPANY MAKING ANY EFFORT TO REDUCE THIS IMPACT?

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

8  
9 **VII. CONCLUSION**

10  
11 Q. PLEASE SUMMARIZE YOUR TESTIMONY.

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

22  
23 Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

24 A. Yes, it does.

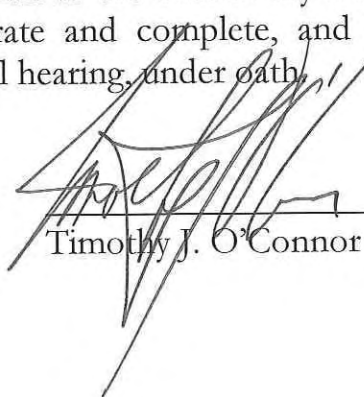
1 STATE OF NORTH DAKOTA  
2 BEFORE THE  
3 PUBLIC SERVICE COMMISSION  
4

5  
6 In the Matter of the Application of Northern )  
7 States Power Company, a Minnesota Corporation )  
8 For Authority to Increase Rates for Electric Service )  
9 in North Dakota )

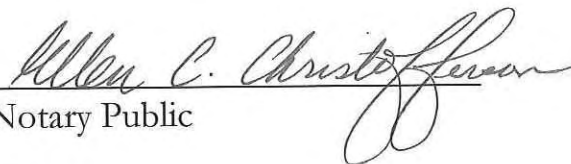
Case No. PU-12-\_\_\_\_

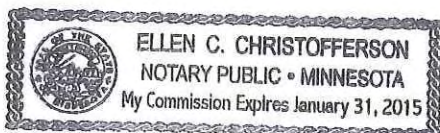
10  
11  
12  
13 **AFFIDAVIT OF**  
14 **Timothy J. O'Connor**  
15

16  
17 I, the undersigned, being duly sworn, depose and say that the foregoing is  
18 the Direct Testimony of the undersigned, and that such Direct Testimony and the  
19 exhibits or schedules sponsored by me to the best of my knowledge, information  
20 and belief, are true, correct, accurate and complete, and I hereby adopt said  
21 testimony as if given by me in formal hearing, under oath.  
22

23  
24   
25 Timothy J. O'Connor  
26  
27  
28

29  
30 Subscribed and sworn to before me, this 11<sup>th</sup> day of December, 2012.  
31

32  
33   
34 Notary Public  
35  
36



## **Statement of Qualifications**

**Timothy J. O'Connor**  
**Acting Chief Nuclear Officer**

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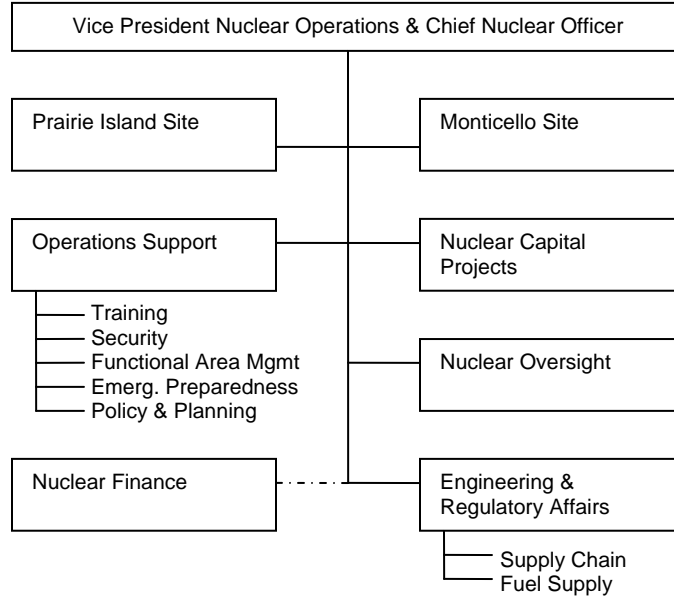
Tim O'Connor is acting chief nuclear officer for Xcel Energy. He is responsible for all Xcel Energy nuclear activities in Minnesota at the Monticello and Prairie Island nuclear generating plants (operated by NSP-Minnesota and its parent company, Xcel Energy.)

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**

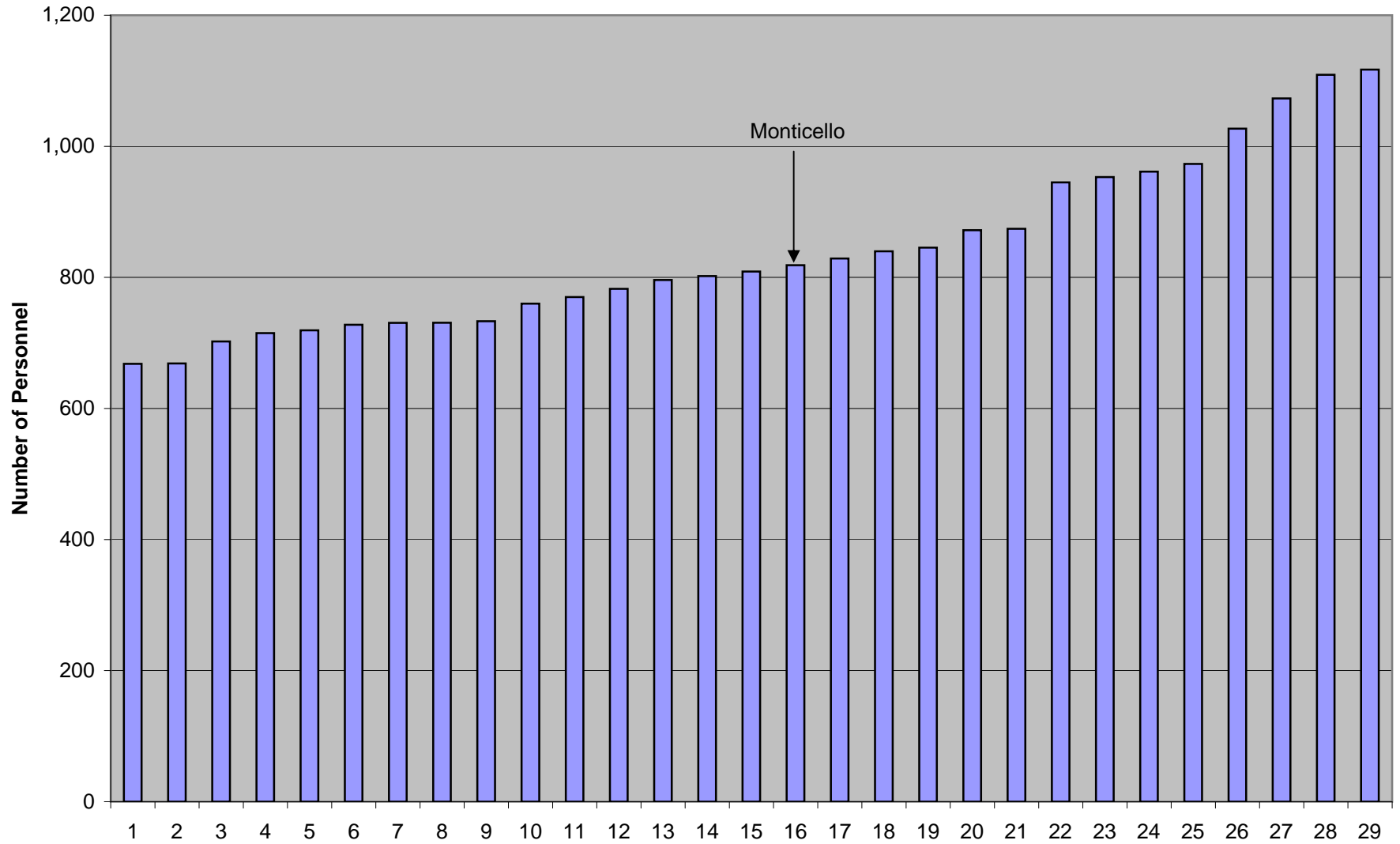
The Nuclear Generation Operations and Support organization oversees Xcel Energy’s nuclear plant operations and the required services to support those operations. The leaders of the areas listed below collaborate as a Nuclear executive team for the oversight of business planning, project prioritization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

**Key Organizations and Activities:**

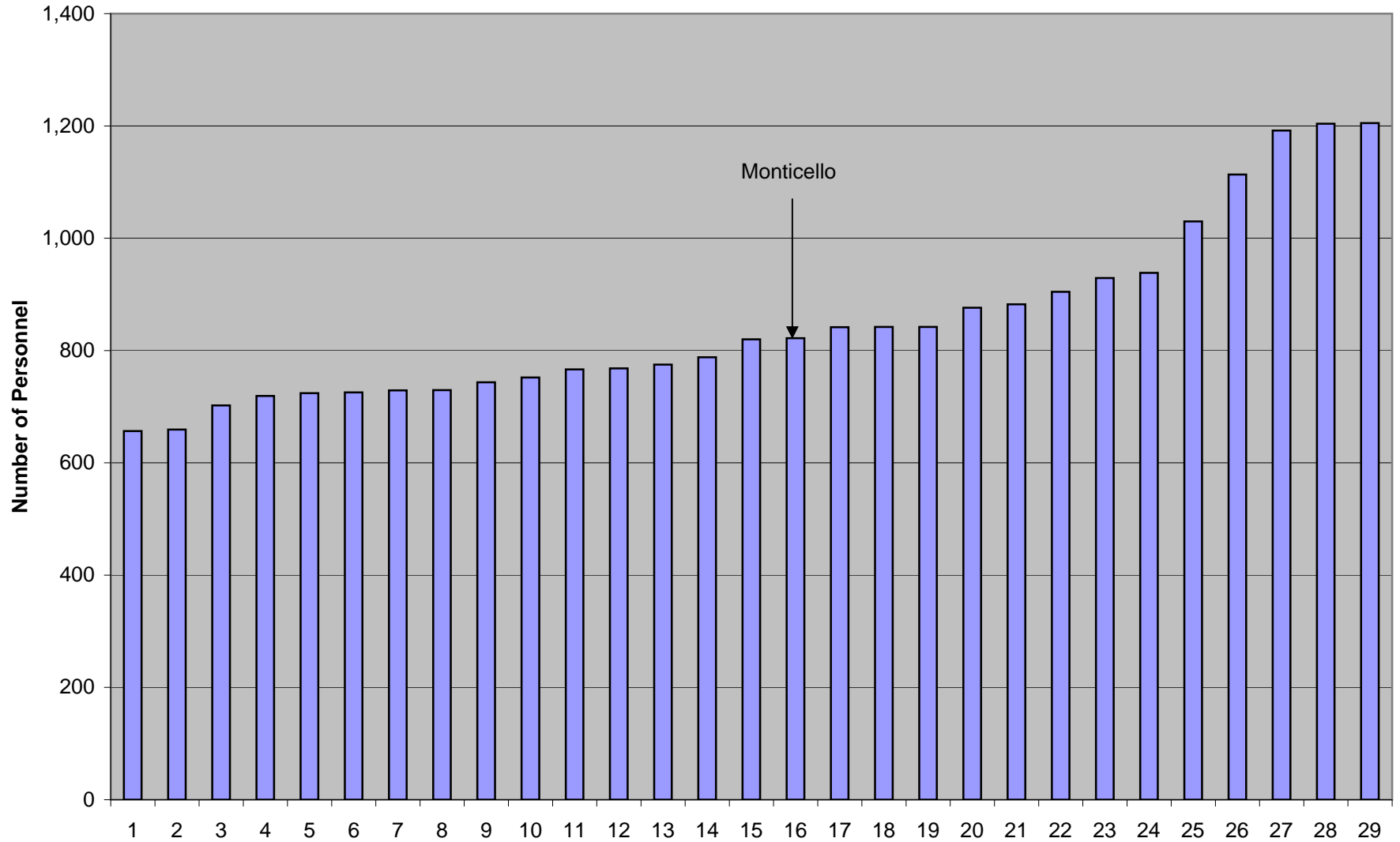
- **Monticello and Prairie Island Sites** – The Site Operations organization at each plant oversees the safe day-to-day operation of the generating plant and the strategic implementation of all functions performed at/for the site. These functions, which include regulatory/environmental compliance, security, 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.

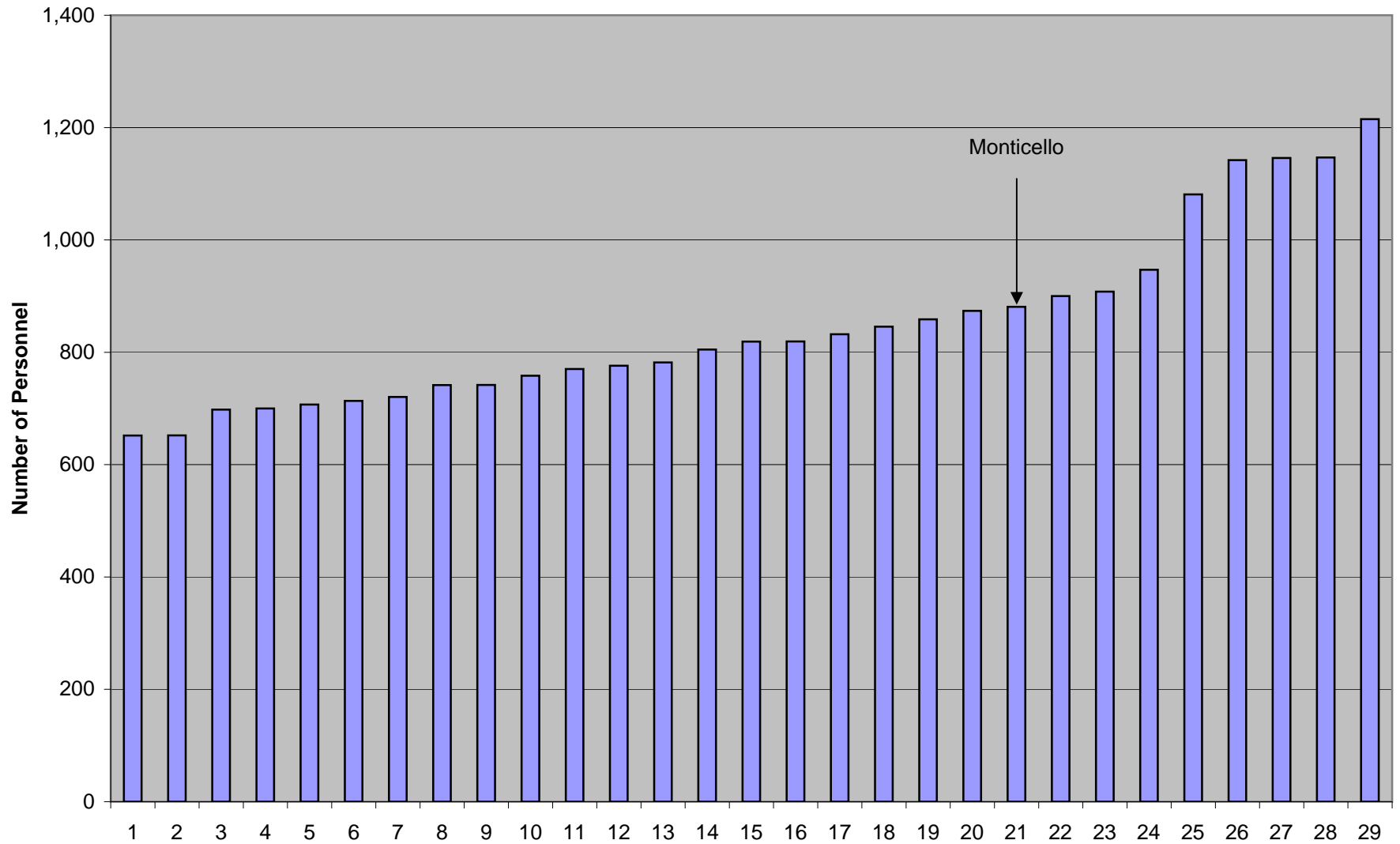
### 2009 Single Unit Staffing



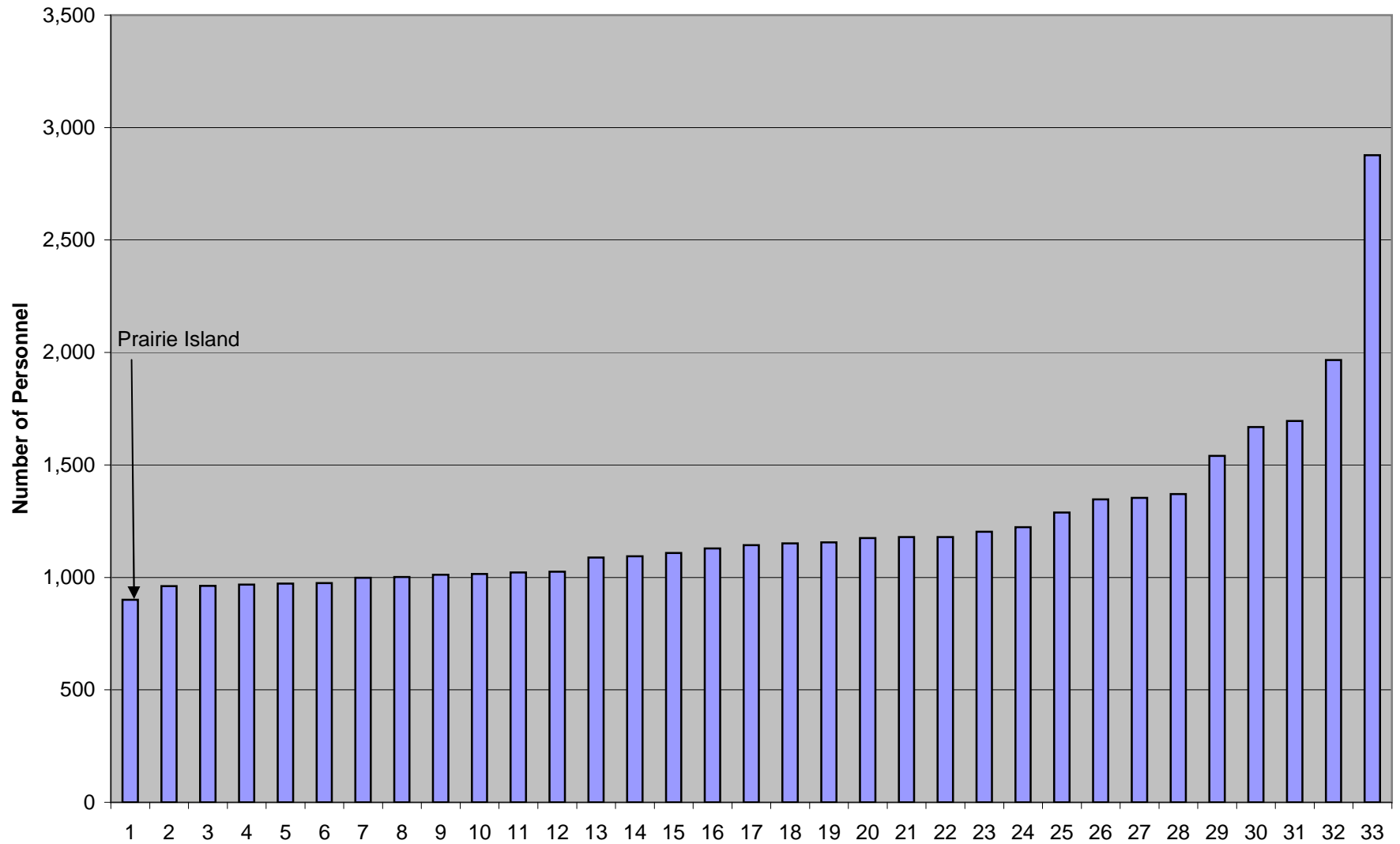
### 2010 Single Unit Staffing



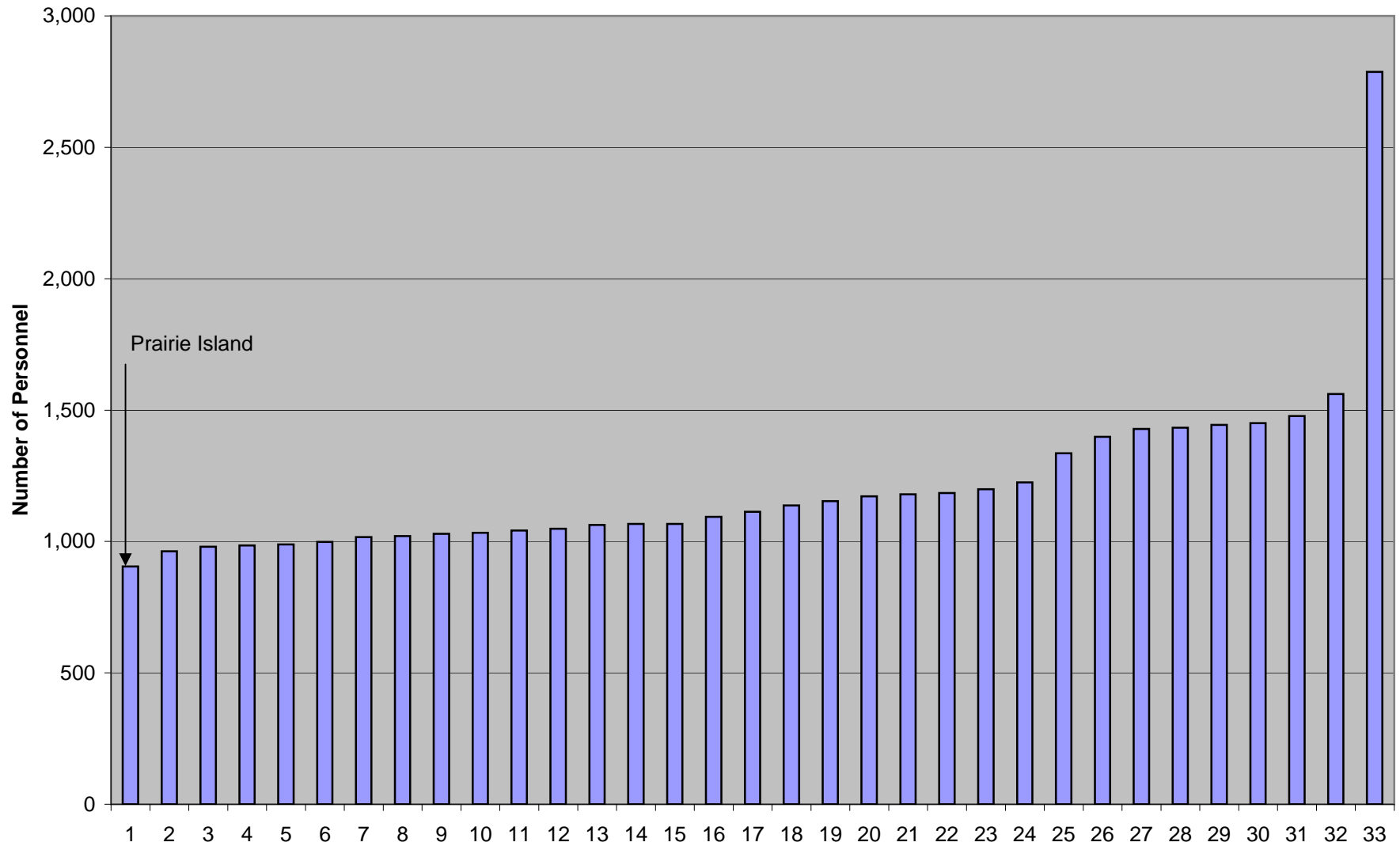
### 2011 Single Unit Staffing



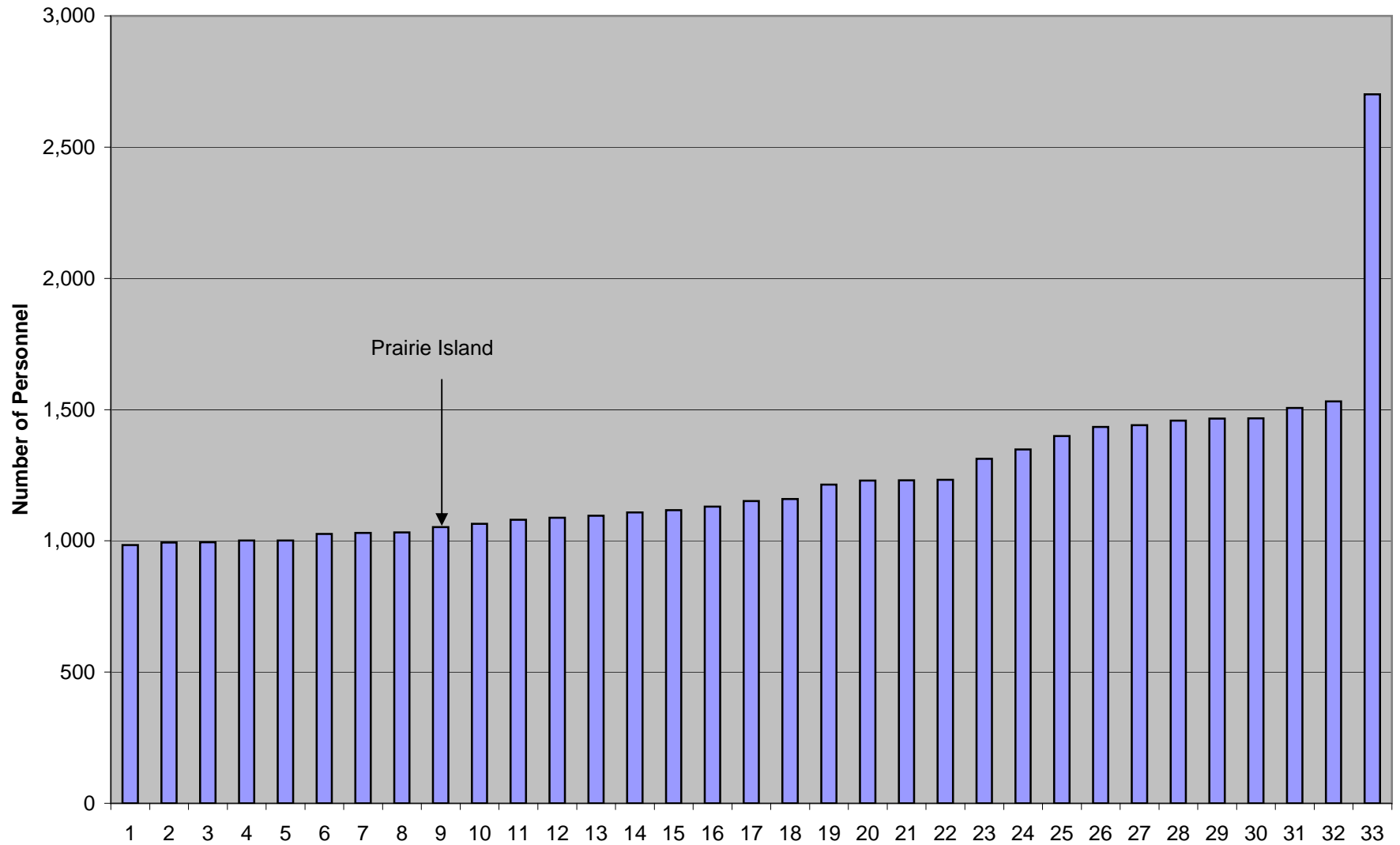
### 2009 Dual Unit Staffing



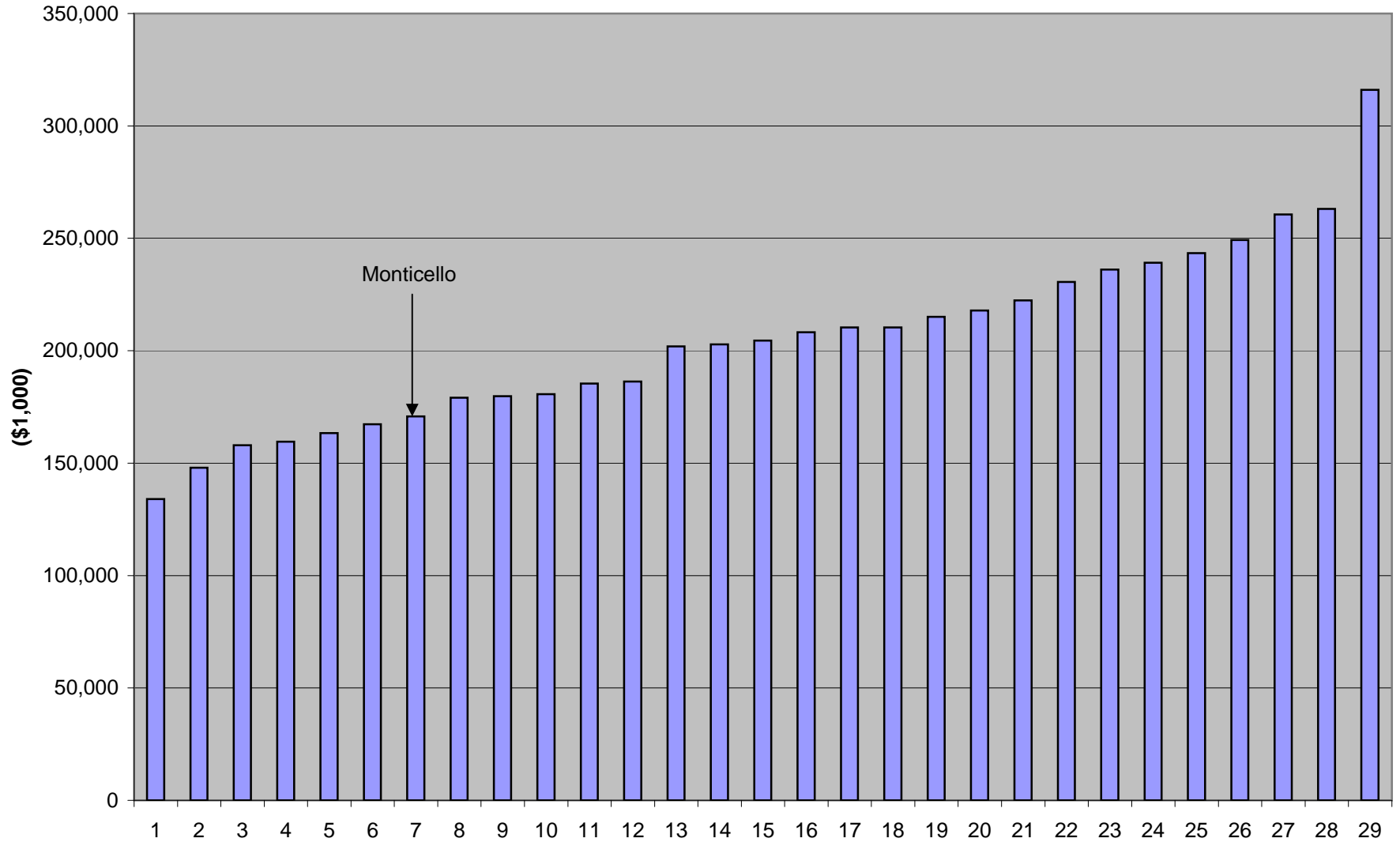
### 2010 Dual Unit Staffing



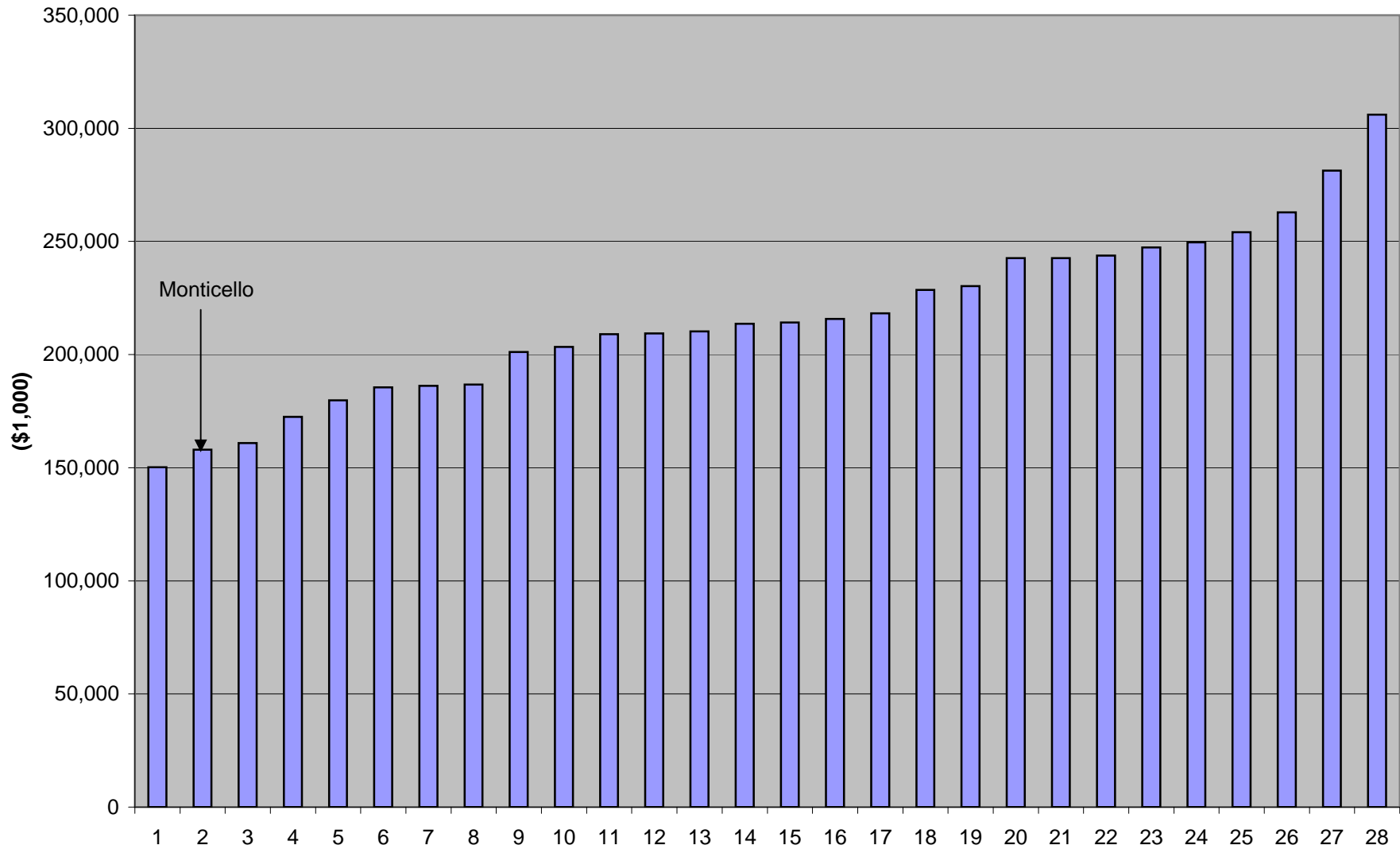
### 2011 Dual Unit Staffing



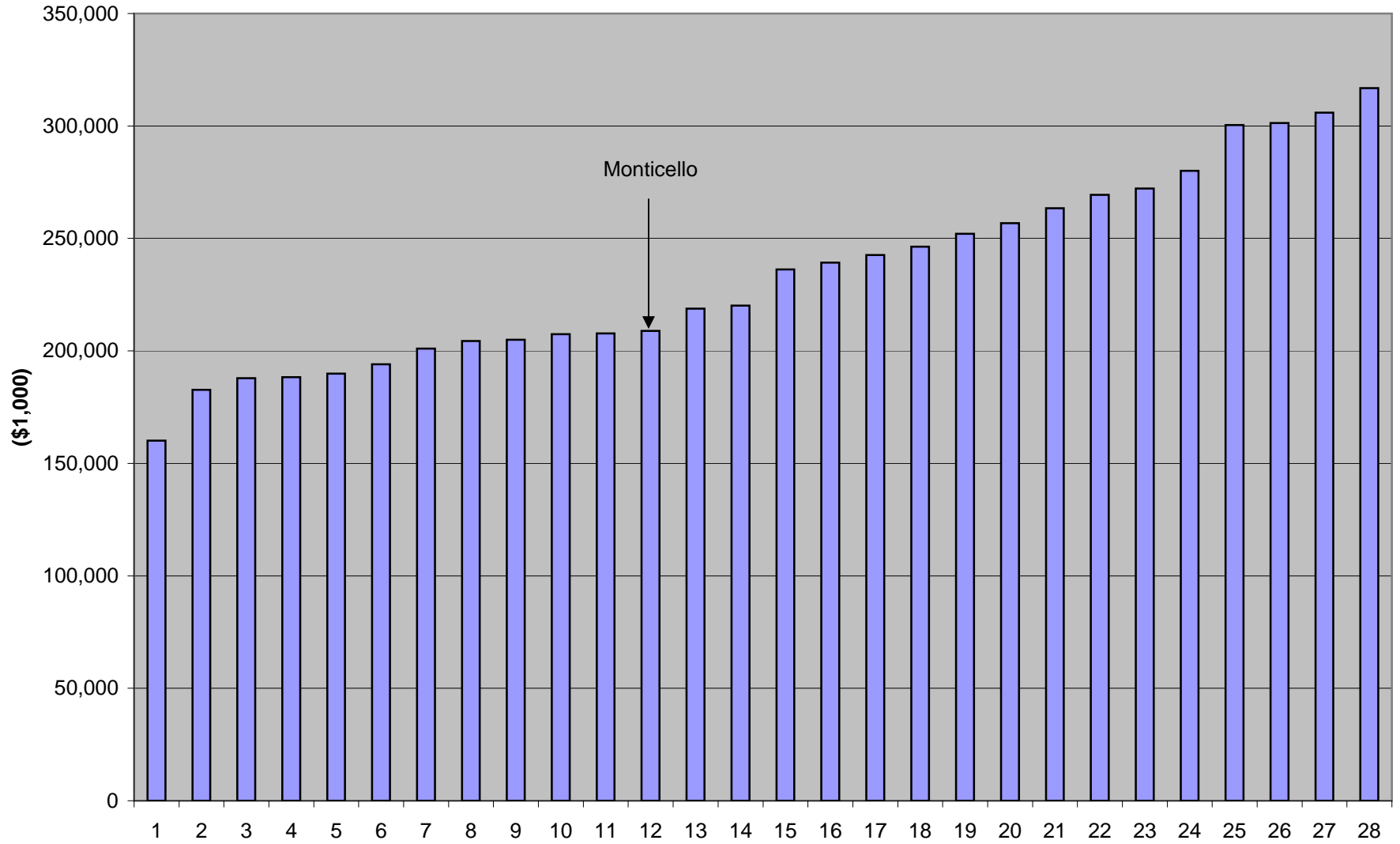
### 2009 Single Unit Operating Costs



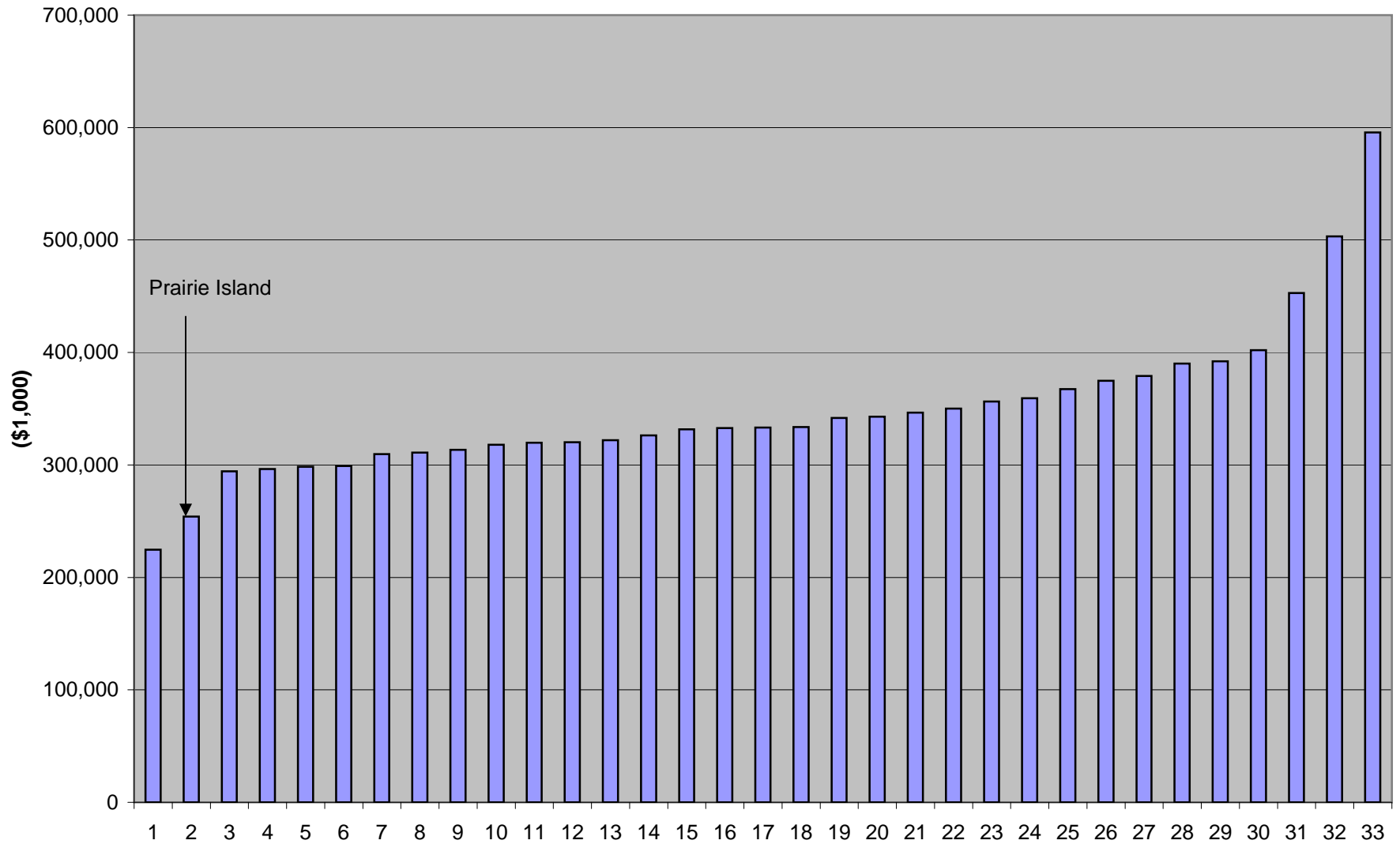
### 2010 Single Unit Operating Costs



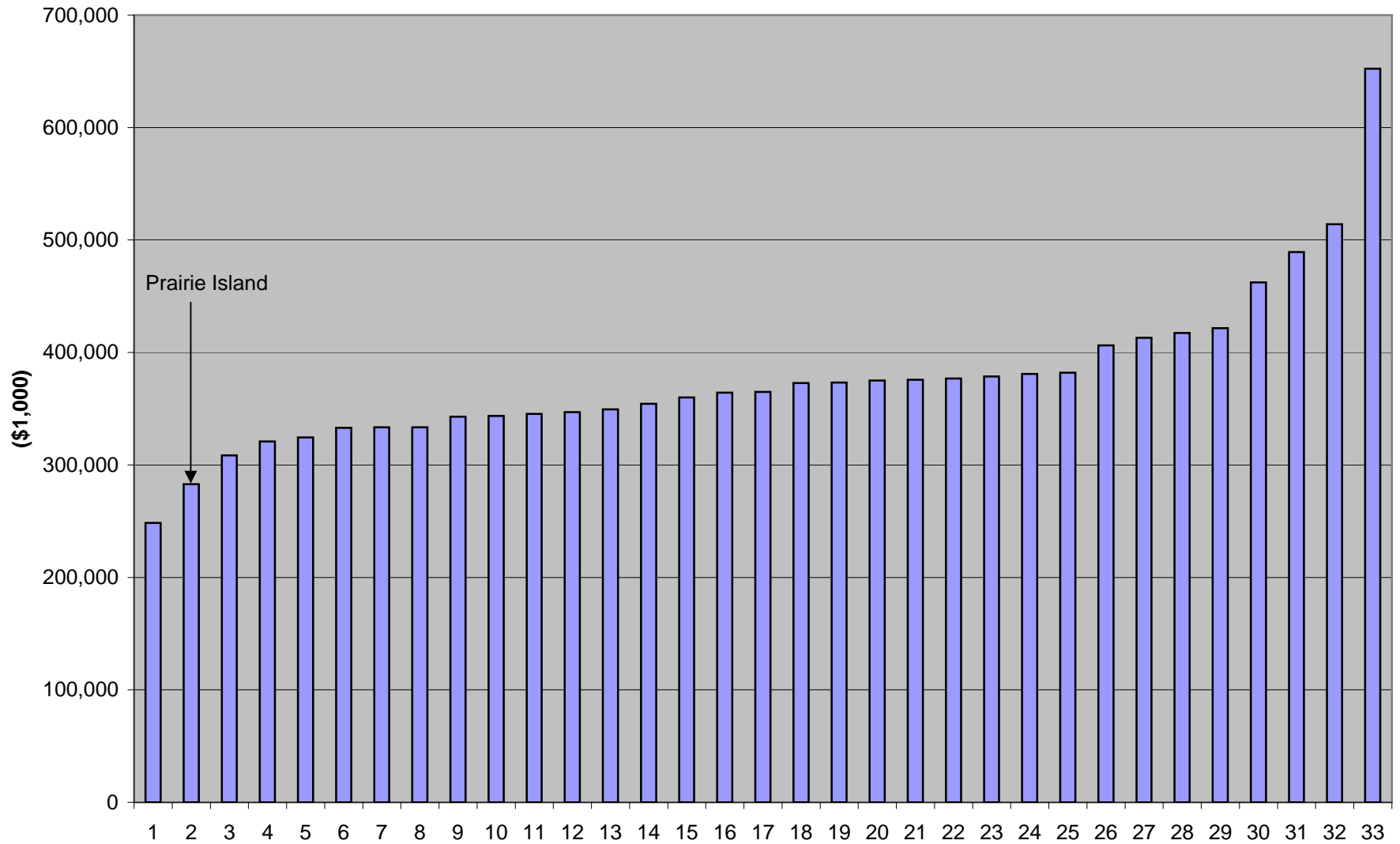
### 2011 Single Unit Operating Costs



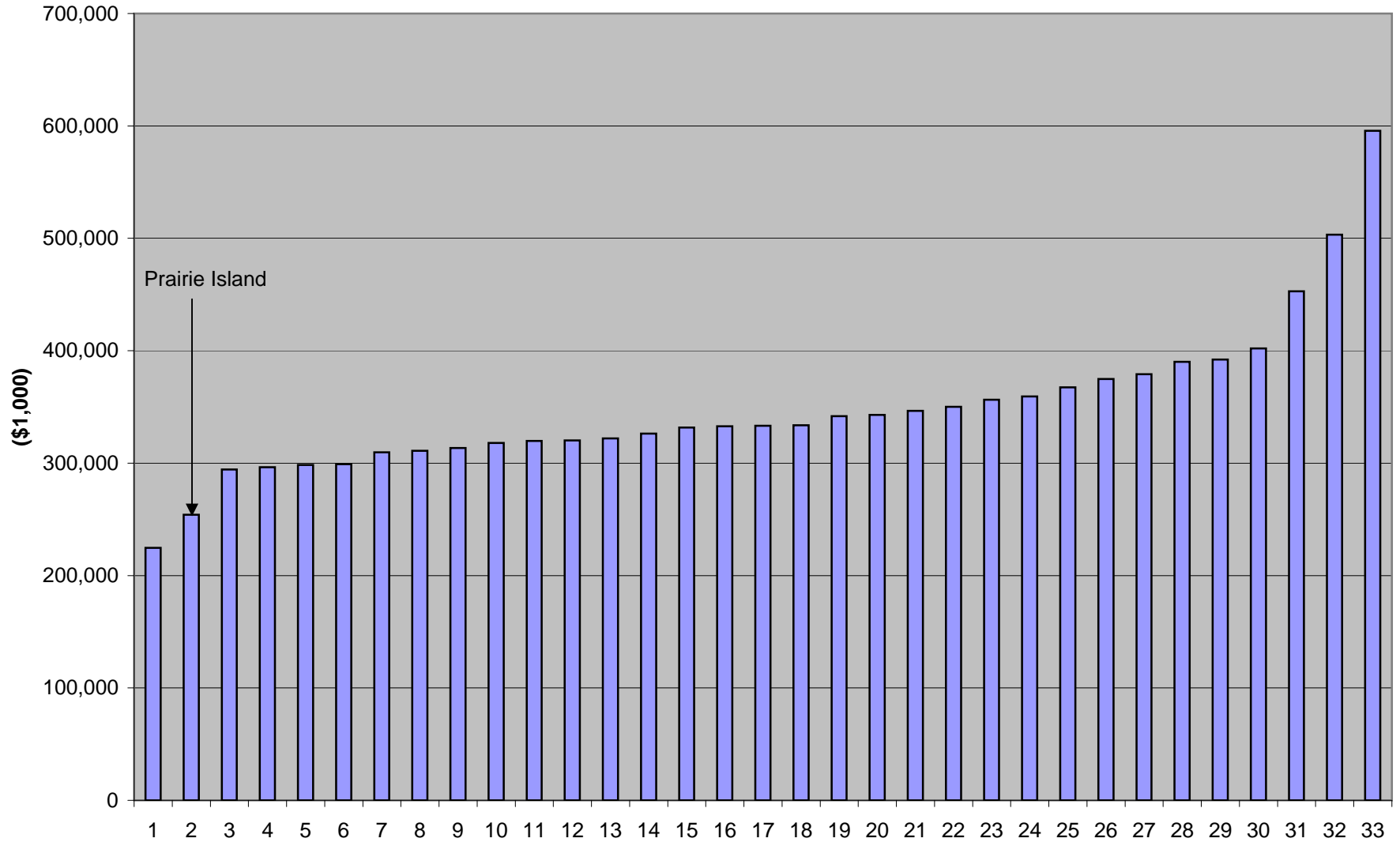
### 2009 Dual Unit Operating Costs



### 2010 Dual Unit Operating Costs



### 2011 Dual Unit Operating Costs





## MONTI LCM/EPU COST FORECAST

By Year / w Child WO

October 2012

Case No. PU-12-\_\_\_\_  
Exhibit\_\_\_\_(TJO-1), Schedule 4  
Page 1 of 2

Parent WO	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
<b>10245258</b>											
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



## 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 9 Checkbook & Other									18,963,786	19,376,771	38,340,557
									1,509,411	(24,828,443)	(23,319,032)
<b>10245381</b>											
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
<b>TOTAL EPU \ LCM</b>	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			
<b>TOTAL EPU \ LCM</b>	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
<u>Outage Costs (Spend)</u>					
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%
<b>Total Outage Costs (Spend)</b>	<b>\$67.3</b>	<b>\$91.9</b>	<b>\$24.6</b>	<b>36.6%</b>	<b>18.3%</b>

**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) <sup>1</sup>	(91.9)	(23.9)	35%	17.5%
Outage Amortization	59.8	74.5	14.7	24.1%	12.0%
<b>Net Outage-Related Nuclear Costs for Year</b>	<b>\$59.1</b>	<b>\$74.5</b>	<b>\$15.4</b>	<b>26.1%</b>	<b>13.0%</b>

<sup>1</sup> 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**

	RATE CASE ADJUSTMENTS				Revised 2013 Budget - Total Nuclear
	Initial 2013 Budget - Total Nuclear	(1) Top Level Adjs to O&M	(2) Top Level Adj Retention	(3) Top Level Adj 2012 Outage	
<b>Non-Outage Costs</b>					
<i>Site Costs</i>					
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
<b>Total Controllable Non-Outage Costs</b>	<b>\$ 181,742,443</b>	<b>\$ 7,449,000</b>	<b>\$ 1,383,042</b>	<b>\$ -</b>	<b>\$ 190,574,485</b>
<i>Non-Site Costs</i>					
Nuclear Fees	\$ 33,082,913	\$ 1,500,000			\$ 34,582,913
Security - G4S contractor	\$ 26,511,501	\$ 700,000			\$ 27,211,501
<b>Total Discretionary Non-Outage Costs</b>	<b>\$ 59,594,414</b>	<b>\$ 2,200,000</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 61,794,414</b>
<b>Total Non-Outage Costs</b>	<b>\$ 241,336,857</b>	<b>\$ 9,649,000</b>	<b>\$ 1,383,042</b>	<b>\$ -</b>	<b>\$ 252,368,899</b>
<b>Outage Costs - Spend</b>					
Monticello outage costs	\$ 49,423,305				\$ 49,423,305
Prairie Island outage costs	\$ 42,435,062				\$ 42,435,062
<b>Subtotal - Total Nuclear Generation O&amp;M Spend</b>	<b>\$ 333,195,224</b>	<b>\$ 9,649,000</b>	<b>\$ 1,383,042</b>	<b>\$ -</b>	<b>\$ 344,227,266</b>
<b>Outage Costs - Net</b>					
Nuclear Generation Outage Spend (per above)	\$ 91,858,367				\$ 91,858,367
Deferral & Amortization Adjustment:	\$ (19,381,736)		\$ 2,009,472		\$ (17,372,264)
<b>Outage Costs - Net of Deferral/Amortization</b>	<b>\$ 72,476,631</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 2,009,472</b>	<b>\$ 74,486,103</b>
<b>Total Nuclear O&amp;M - Non-Outage &amp; Outage- net</b>	<b>\$ 313,813,488</b>	<b>\$ 9,649,000</b>	<b>\$ 1,383,042</b>	<b>\$ 2,009,472</b>	<b>\$ 326,855,002</b>

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 estimate 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
<b>Total O&amp;M adjustments</b>	<b>\$ 9,649,000</b>

(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
<b>Total increase in fall 2012 outage costs</b>	<b>\$ 3,680,000</b>
<b>2013 amortization impact</b>	<b>\$ 2,009,472</b>