STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
David C. Boyd	Commissioner
Nancy Lange	Commissioner
J. Dennis O'Brien	Commissioner
Betsy Wergin	Commissioner

In the Matter of a Commission Investigation into Xcel Energy's Monticello Life-cycle Management/ Extended Power Uprate Project and Request for Recovery of Cost Overruns

Docket No. E002/CI-13-754

XCEL ENERGY'S REPORT ON MONTICELLO LCM/EPU PRUDENCE

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, respectfully submits this Report to the Minnesota Public Utilities Commission to facilitate the investigation of the prudence of our costs in support of the Monticello life-cycle management ("LCM") and extended power uprate ("EPU") projects (the "LCM/EPU Program" or the "Program"). In its September 2, 2013 Order in our recent rate case (Docket E-002/GR-12-961), the Commission opened this Docket:

> The Commission opens a new proceeding to investigate the prudence, reasonableness, and rate recoverability of the Monticello LCM/EPU project, *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life-cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, Docket No. E-002/CI-13-754.

We committed to a prudence review of the Program in our test year 2011 and 2013 rate cases, and we agreed to provide a comprehensive explanation of the costs we incurred. We also agreed to waive any defense we may have that the outcome of this investigation could be limited by the prohibition against retroactive ratemaking.

This filing and the accompanying testimony and exhibits will provide the Commission with information it will need to begin its assessment of Xcel Energy's prudence in pursuing and implementing the LCM/EPU Program. While our costs were substantially higher than initially anticipated, this was primarily due to (i) necessary changes in scope and design to meet our goals and regulatory requirements; (ii) actual installation costs, which turned out to be much higher than we predicted; and (iii) delays and added costs in our federal licensing effort. We believe we made prudent decisions based on the information that was available to us at the time. We adapted appropriately to evolving circumstances and managed the process reasonably, sometimes in adverse circumstances. The upgrades remain cost-effective even after consider the actual cost and timing of the implementation. We appreciate the opportunity to provide the Commission with this filing and look forward to working constructively with the Department, the Commission's investigator, and stakeholders to build a complete record for the Commission's consideration.

II. SUMMARY

The Monticello LCM/EPU Program was a highly complex undertaking that in many ways was more complicated than the original construction of the plant. Refurbishment work at an operating nuclear plant presents special challenges due to the precautions that we take to ensure the safety of our workers, customers and surrounding communities. This project required replacing hundreds of pieces of equipment into the plant's existing small footprint. It required the dedicated effort of thousands of workers during three implementation outages (2009, 2011, 2013) to complete installation.

This challenging Program was conceived to serve two separate but overlapping purposes. The first was to undertake LCM activities to support the safe and reliable operation of Monticello through 2030. Many of these actions were required to comply with our aging management plan that was a condition of receiving our license extension. The second was to increase Monticello's available capacity to help us fill a need for additional baseload capacity that was identified in our 2004 and 2007 resource plans. To increase Monticello's capacity we needed to (i) obtain a license amendment from the Nuclear Regulatory Commission ("NRC") authorizing the increase, and (ii) implement the modifications necessary to achieve the increase.

We recognize that completing the Program took longer and cost more than we anticipated. The initial cost estimate was $320 million. The final cost as of August 31, 2013 is $665 million.[1] The cost increases we experienced were primarily driven by three factors.

First, we expanded the scope of a number of modifications generally to address long-term plant needs in support of both the LCM and EPU goals. Several components that we initially expected to repair or recertify required replacement to complete the Program safely and to assure reliable operations for the extended license period. The design and engineering of these component replacements increased costs. While we understood that the expanded scope would increase costs, we did not foresee the magnitude of the scope changes had on the initiative. In the spring of 2010, we had forecasted that the project to cost $400 million. Overall, major changes to project scope related primarily to four major modifications that drove a large portion of our cost increase.

Second, installation of the modifications was more difficult and expensive than we foresaw. This was the first major construction program to occur at Monticello. In

[1] This is the total cost incurred through August 31, 2013. Final costs will vary slightly as we forecast about $5 million additional for final licensing costs and to implement the procedures for power ascension to uprate levels once the license is granted. The $670 million forecasted total may be subject to reduction based on potential offsets and other issues. We will use $665 million for this filing. Note that Xcel Energy will be filing a general rate case shortly after this filing. In that rate case, Xcel Energy will include approximately $655 million (plus an allowance for AFUDC) in the test year rate base for the LCM/EPU Program, as this was the final estimated total as of the time the rate case budget closed in May. Given that there is potential for some movement in the total due to final accruals and resolution of outstanding issues, we did not update the budget for the test year in the upcoming rate case.

past years, we invested in capital maintenance to repair, strengthen and replace components or equipment. We found that there are significant difficulties of multiple major construction activities at an operating nuclear plant, many of which occurred in remote and radiologic portions of the plant. We found that space for installation was extremely tight; it was necessary to remove or work around hundreds of interferences, and our productivity was slowed due to the specialized and time-consuming procedures to ensure worker safety in radiological and electrically sensitive areas of the plant. In addition, we had to address several issues that arose based on conditions found during the implementation outages. We spent nearly $300 million for implementation costs alone, by far the largest category of costs incurred for the initiative.

Third, NRC licensing for the EPU was challenging. The NRC's review of our application (five years) took much longer and cost double what we originally expected. Much of the delay was the result of increasingly-conservative regulatory requirements that were outside of our control. Nevertheless, on September 5, 2013, we received approval from the Advisory Committee on Reactor Safeguards (the final step prior to NRC approval), and we anticipate receiving the NRC's uprate approval by the end of 2013. Once we receive the EPU license amendment, we will begin the process of ascending to the higher power levels authorized by the license amendment.[2]

We obtained a number of valuable and tangible benefits for the safe and reliable operations of the plant from the Program. Specifically,

- Our work substantially improves electrical performance in the plant, reduces the likelihood of trips and forced outages, and increases reliability;

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[2] We can ascend to full uprate capacity after we receive NRC approval to adjust Monticello's nuclear fuel configuration. This is called the MELLLA+ amendment request, which stands for "Maximum Extended Load Line Limit Analysis Plus." This is an engineering analysis that provides for greater operational flexibility, permits more efficient reactor startup, maximizes fuel utilization and improves fuel cycle economics. We filed that amendment request in 2010 and anticipate it should be granted in early 2014. Prior to receiving the MELLLA+ license amendment, the plant should be able to ascend to about 640 MW.

- We added safety margin and restored operational margin that had been utilized with changes to the plant over time, positioning us well for the future;

- Some installations are providing unexpected benefits that could lower the O&M costs of the plant for the remainder of its useful life;

- We replaced degraded wiring and obsolete controls to support the extended operations of the plant that will avoid future capital additions and the potential for unplanned outages as these issues were discovered; and

- We avoided costly retraining and major changes to daily operations by selecting designs that ensure the plant remains operator-friendly.

Although our costs were much higher than anticipated, we are confident they were what it took to complete the level of activity in the timeframe that we pursued the Program. We completed a significant amount of work and the plant is safer, and will operate more efficiently and reliably as a result. It is important to consider the benefits we obtained from this Program relative to the nature of this asset. Even without the uprate, Monticello provides value as our work supports its sustained availability through 2030. The upgrades we made will serve our customers and the State well into the future as the plant is much better prepared to adapt to the new requirements and higher expected levels of safety margins that will be expected in a post-Fukushima environment. Upon obtaining the EPU license amendment, Monticello can provide 671 MW of reliable baseload power. Generation from Monticello remains cost-effective when considering the overall cost of the Program. Even the incremental 71 MWs are roughly equivalent to a natural gas alternative when evaluated by an avoided-cost analysis. Monticello provides our system with valuable diversity of supply and carbon-free energy and is an important resource at a time when the federal government is increasing its regulation of fossil-fuel emissions.

III. BACKGROUND

A. Life Extension and Uprate

In 2003, we began to take steps to renew our NRC operating license for Monticello, after a Minnesota law was changed making an extension feasible. *See* Minn. Stat. §§ 116C.83 and 216B.243, subd. 3b. In 2005-06 we obtained a certificate of need from the Commission that allowed us to store spent fuel at the site and we received our license renewal from the NRC, authorizing us to operate the plant through 2030. In 2006, we decided to combine our required LCM program for the plant with an effort to seek an EPU to add an additional approximately 71 MW of capacity. In late 2008, we filed an application with the NRC to obtain a license amendment for us to operate Monticello with additional capacity. In January 2009, we obtained a certificate of need from the Commission for authority to construct the upgrades necessary to achieve the uprate.

We chose to multi-track the initiative to meet the Company's forecast need for additional baseload capacity. Thus, we proceeded with the licensing, design, engineering and implementation project phases concurrently. This approach, while accepting some risk, was beneficial to our customers' interest in that we expected to provide the benefits of the LCM/EPU Program as soon as possible.

B. Xcel Energy's LCM/EPU Experience

When we renewed our operating license at Monticello, we knew that we needed to make capital improvements to support the plant's extended life.[3] In addition, at the time we started the LCM/EPU Program in 2006, a number of utilities had

[3] It turned out that this 40-year-old plant had more systems that needed replacement than we anticipated when we began the process of obtaining authorization to renew its license in 2005. Therefore, as part of the present LCM/EPU initiative, we ended up having to replace more systems than we planned.

completed EPUs successfully. This suggested it was a reasonable decision to consolidate our LCM with the EPU activities. Finally, our 2004 and 2007 resource plans showed strong growth in forecast demand and significant need for baseload generation. The forecasts at that time reflected a need to add over 1,000 MW of incremental new generation in the planning horizon.[4]

The combination of these factors – need for LCM upgrades, opportunity for EPU, and need for additional capacity – convinced us to pursue the Program at Monticello as promptly as possible. This led us to take some risk in our development approach by multi-tracking the effort and expending capital prior to having all of the Commission or NRC approvals in place ahead of time. We recognized that if we did not take this risk we could not complete the Program on the schedule to meet our capacity need.[5]

As the Program moved forward in the 2009-11 timeframe, however, we encountered several unexpected developments that increased our costs and caused delays. These cost drivers fit within three broad categories:

- Scope. Our decision to multi-track the initiative caused us to rely on high-level, preliminary cost estimates that were based on a conceptual scope. As a result, our scope did not capture all of the work that needed to be completed and our initial estimates were too low.

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[4] Since 2010, our forecast demand has been soft, largely as a result of the aftermath of the economic downturn in 2008-09. In addition, since about 2011, natural gas prices have fallen sharply and now are at historically-unprecedented low prices due to the commercialization of hydraulic fracturing and horizontal drilling. By the time these two fundamental changes in the energy sector had become clear, we had already spent over half of the capital in furtherance of the Program.

[5] Even as the forecast began to change, it was appropriate to proceed promptly. There was still concern that the forecast could bounce back as the magnitude and duration of the changed demand was not yet clear. Also, moving promptly allowed us to preserve the maximum benefit of the Program by trying to obtain the maximum-possible number of years under our renewed license to (i) obtain extra energy benefit for our customers, and (ii) optimize our investment to allow for depreciation over a longer period given that our extended license was only for an additional 20 years.

- Implementation. Installation was more difficult and costly than we expected, accounting for nearly half of the overall Program costs. We discovered more equipment that needed replacing than we expected and encountered difficult as-found conditions that drove up costs in part by the need to install some larger components in preexisting spaces. We faced challenges obtaining and retaining experienced workers, and we needed to manage our vendors actively.

- Licensing. Unlike prior EPUs, the NRC licensing effort for Monticello has been pending for five years and has been beset by major difficulties that were outside of our control. We believe the events at Fukushima in early 2011 further complicated our efforts as the key outstanding license issue caused the agency to focus more intensely on natural disasters and the capability of retaining reactor cooling with the loss of on-site power.

We acknowledge that our cost estimation was too low. However, based on the analysis in this filing, better foreknowledge would not have materially changed the costs or changed the need for us to do the work. Major construction at a 40-year-old nuclear plant is expensive, whether or not we had accurately predicted it.

C. Recent EPU Experiences at Other Facilities

We were not alone in this experience. Other utilities who recently completed major construction projects have likewise found that the cost was much higher than initially thought. Information on the recent experience of a number of other nuclear facilities place the Company's experience in context of a rapidly evolving industry and provide a frame of reference for judging our actions. Notably, the experience of others, such as nuclear units in Florida, is instructive. The uprates at those units were more expensive, both in dollar increase and percentage increase than our experience at Monticello. These examples show that the environment around nuclear generation and EPU initiatives changed dramatically in the last few years as a result of increasing NRC regulatory challenges. While some other utilities spent less than us, it appears this was driven by relatively smaller scope of work at some of those units. A substantial portion of our testimony discusses why the significant scope of the Monticello Program was appropriate. We discuss below the implications of the prior State law limiting on-site nuclear fuel storage. It was not until 2003 that the Company could consider life extension and the investments that go with it. As a result, we were behind in our modernization efforts for the plant.

D. Cost Effective Generation

This filing provides an analysis of the cost-effectiveness of the work we did at Monticello. As part of this filing, we confirmed that at a total cost of $665 million, continued operations at Monticello remains valuable to our customers compared to replacing Monticello with combined-cycle natural gas generation. Our analysis focuses on the value of Monticello as a whole because most of the upgrades implemented were required to keep the plant operational for the renewed license period.[6]

1. *Monticello as a Whole Remains Valuable*

Using the 2008 model from the certificate of need proceeding, we provide an analysis of the cost effectiveness of Monticello using the actual total cost of the LCM/EPU Program of $665 million rather than $320 million (as was modeled in 2008). Had we decided not to undertake all of the LCM projects that we did as part of this initiative, we would have had to shut Monticello down prematurely. That analysis shows that, had we known the upgrades at Monticello would cost $665

[6] We note that a realistic option to cancel the LCM/EPU Program was not available for Monticello. Decisions to cancel uprates at other facilities occurred prior to construction, making cancellation a feasible alternative. At Monticello, construction began in 2009 when the full impact of the recession was not known and natural gas prices were high and expected to remain so. We had constructed a substantial number of the modifications by mid-2011 and had expended about $400 million. In light of the significant progress that had been made, it was not feasible or prudent to stop. Further, all of this work was premised on an integrated LCM/EPU approach and we could not have stopped one aspect without completely redesigning the other.

million, Monticello remained cost effective on a present value of societal costs ("PVSC") basis. This scenario shows that in 2008 continued long-term operation of Monticello as a whole saves our customers more than $1.3 billion PVSC in 2008 compared to shutting Monticello down in 2011 and replacing it with natural gas generation.

We ran similar modeling in 2013 using our current Strategist model and confirmed that retaining Monticello as part of our fleet remains valuable under 2013 conditions. The situation in 2013 is quite different from what existed in 2008. Natural gas prices have fallen and forecast demand growth has declined. This means that natural gas generation is more attractive on a purely cost-per-kWh basis. Nevertheless, despite all of the changes, retention of Monticello through 2030 results in a net savings to customers of more than $170 million on a PVSC basis compared to a scenario where we did not extend Monticello's operating license and replaced it with natural gas in 2011.

We provide this analysis because almost all of the modifications were required to be upgraded in order to continue to operate the plant through its extended license period. This analysis confirms that retaining generation at Monticello was the right choice even at the higher cost encountered by this Program.

2. *Implementation Analysis*

To test this proposition, we conducted an assessment of the value of the remaining investment to recognize that costs were incurred over time. We conducted a yearly analysis from 2008 to 2013 that compared the remaining LCM/EPU costs to forecasted benefits at the same timeframe. In each instance we factored in only the costs remaining of the $665 million toward completion and did not include costs that were already sunk. Each year along the way Xcel Energy's decision to continue with the Program was in customers' interest, as stopping the Program and closing the plant would have resulted in excess customer costs. We added an additional test that did not remove our sunk costs to determine if there was a point at which the net benefits narrow substantially so that further evaluation was appropriate. The first significant narrowing occurred in 2012, well after we were committed to completion.

3. Incremental Megawatts

If the Commission wants to consider the value of the incremental 71 MW as it did in the certificate of need proceeding, we also provide this alternative analysis. We do not believe that the incremental value is the best way to assess Monticello's worth, as we approached the life-cycle management investments and our uprate investments as an integrated project with a single purpose. The cost of the incremental 71 MW is roughly equal to, or more expensive than, a natural gas alternative, depending upon the assumptions used. But this analysis results in an overly narrow view of the value of that generation and is not reflective of the plant's support of transmission reliability or the value of fuel diversity.

IV. DESCRIPTION OF LCM/EPU PROGRAM

Monticello is a 600 MW single-unit boiling water reactor ("BWR") nuclear power plant. It commenced operations in 1970 pursuant to a 40-year operating license granted by the NRC. Because Minnesota legislation from the early-1990s effectively precluded us from renewing our operating license, we did not expect to be able to operate beyond 2010. As a result, the Company deferred major capital projects and upgrades and focused only on those repairs necessary for the plant to operate safely through retirement in 2010.

A. Genesis of the Program

In 2003, a new Minnesota law made it possible for Xcel Energy to seek a 20-year operating license extension. In 2006, Xcel Energy obtained both state and federal permits needed to continue operations until 2030.

Our commitment to nuclear safety requires that we ensure plant systems and equipment are maintained or replaced as necessary to ensure safe and reliable operation for the duration of the extended license period. The LCM/EPU Program grew out of our recognition that, with a renewed operating license, we had considerable work to do for the continued safe and reliable operation of the plant.

In that same timeframe, Xcel Energy was experiencing significant forecast demand growth. Forecasts at the time indicated the need for over 1,000 MW of new capacity in the planning horizon. In our resource plan proceedings, we considered ways to meet that increasing demand, including uprating the capacity at some of our existing generators, such as Monticello. We determined that if we increased the size and function of certain systems and components, we could increase Monticello's capacity by about 71 MW with no incremental change in the nuclear fuel used. Thus, we decided to combine our LCM activities with an EPU to increase Monticello's capacity in order to contribute to meeting our forecast demand.

The EPU required both a certificate of need from the Commission and an NRC license amendment. We recognized that the timelines were short for us to obtain those permits and develop and build the upgrades in time to meet the forecast demand. In addition, with our renewed operating license set to expire in 2030, we wanted to complete the upgrades as soon as possible to provide our customers the benefits of the incremental energy from Monticello for as long as possible and also to allow us the maximum available period over which to amortize the investment. For all these reasons, it was necessary for us to multi-track our initiative and begin implementing the Program prior to obtaining final approvals.

B. Program Set-Up

The preliminary scope for the Program took shape in 2006-07 and grew to include two additional components by the time we sought the certificate of need in 2008. Our 2008 cost estimate was $320-$346 million, based on our preliminary review of the work needed to support long-term plant operations and information we received from our external design engineer about systems that would need to be addressed. In developing the Program, the Company did not attempt to allocate between the uprate and life extension aspects of the Program, but rather viewed them as part of a single integrated initiative.

Further development occurred as we began working through the NRC license process. We filed our initial amendment request with the NRC in March 2008; that application included modifications to a piece of equipment called the "steam dryer," which is used to reduce the moisture content (liquid water) of the steam that is transferred from the reactor to the high and low pressure turbines. Later in 2008, we concluded we needed to replace the steam dryer instead of modifying it. We refiled our NRC application in November 2008 with this new approach.

While we were seeking the certificate of need in 2008, we were simultaneously working on the EPU license amendment request. Despite not yet having those authorizations in place, we spent considerable effort and capital getting ready to commence construction almost immediately after we received the certificate of need. The Commission granted that permit in January 2009 and we proceeded immediately to install the modifications during our normal refueling outages in spring 2009. Our initial plan was to complete the installations in the spring refueling outage in 2011.

C. Cost Drivers

Implementing this Program was much more difficult and took longer than we anticipated. We made design choices for the benefit of the plant that drove additional design and engineering and materials costs. Further, many of the installations were of the type that occur in new construction, but they needed to be deployed within the existing footprint of the plant.

Our initial estimates were based on a high-level conceptual design for the Program. As we moved through the early decisions on design, we chose to undertake work that was central to the long-term viability of the plant, and that enhanced the plant's safety and reliability. As required by NRC regulations and our commitment to nuclear safety, we regularly reevaluate the performance of the plant's systems and components. During the evaluations performed in preparation for the Program we took care to identify all components necessary to enable operations through life extension so that we could implement those changes during the 2009 and 2011 outages. These evaluations resulted in new modifications and component replacements being identified as necessary to complete the LCM/EPU Program.

The Company made key decisions during the Program to substantially expand the scope of these four major modifications and NRC licensing. These key decisions were: (i) replacement of the entire condensate demineralizer system; (ii) replacement of the feedwater heaters and associated equipment; (iii) replacement of the reactor feed pumps and motors; (iv) upgrade of the 4 kV electric distribution system to supplement the on-site power capabilities of the plant; and (v) NRC licensing. Each is described briefly.

<u>Condensate Demineralizer</u>. The initial estimate of the condensate demineralizer modification included replacing the five vessels, upgrading the pre-coat pumps, making small modifications to the existing analog control system and testing.

However, the Company early on identified the need to replace the entirety of the condensate demineralizer system and control panel because the existing system would not support long-term operations or the increased flow requirements at EPU levels. This represented a substantial increase in scope that necessitated unanticipated engineering and design, materials and other costs that we estimate amounted to roughly $27 million.

Installation of that system also proved to be very difficult. When the Company prepared for the installation, we found that replacing the vessels required work in vaults that were extremely confined and radioactive. The original 1960s-vintage vessels had been installed first and the walls of the vaults poured around them. This combination of circumstances resulted in a very difficult and inefficient work environment. A significant number of additional workers had to rotate in and out of the space and our workers had to wear protective gear and comply with restrictive rules concerning exposure to radiation. Our forecasted costs did not adequately address the loss of productivity associated with these conditions. Finally, while we were installing the system, we found that other system components and wiring had degraded and required replacement. This required real-time design and replacement work. This all drove up the cost. In the end, we estimate that installation of the condensate demineralizer system, added $34 million to the cost of the Program.

Feedwater Heaters and Associated Equipment. The original scope called for rerating six feedwater heaters and replacing or modifying other related plant equipment. During the design phase of the Program, however, it was determined that the six feedwater heaters all required replacement. extensive replacement of drain and dump piping. In total, the added scope related to the feedwater heater system accounted for more than $13 million in incremental costs.

Installing the feedwater heaters was a very challenging job that ultimately resulted in an incremental $64 million of costs. Again productivity was a challenge due to the need to resolve numerous interferences and fitting these large pieces of equipment in the available space. The work simply took longer than we predicted. The decision to replace the feedwater heaters also required further analysis and structural modifications to the turbine building floor. In addition to the turbine floor costs, we incurred previously-unanticipated costs with interferences (piping and wiring) related to replacement of the 13 A/B feedwater heaters.

<u>Reactor Feed Pumps and Motors</u>. The initial estimate for this major modification was based on General Electric's recommendation to add a smaller capacity supplemental reactor feed pump and motor. However, the Company determined that the third pump design was not workable due to size limitations and operating procedures. The Company elected to replace the existing pumps and motors with larger capacity equipment to support uprated power conditions and to ameliorate repair issues with the legacy pumps and motors. The increased scope for this major modification led to incremental engineering and design, materials and other costs which we now estimate to be nearly $31 million.

We also incurred about $45 million in additional installation costs as a result of the issues we encountered. Our pump and motor fabricators encountered delays in providing the components because of difficulty fabricating equipment that met our specifications for startup and operations. This required greater on-site presence as well as additional testing efforts. Also, we incurred design costs for new pipe drawings, additional stress analysis, new pipe support calculations, as well as addition piping, as a result of the interferences discovered through our work planning activities. Our implementation costs also were increased by our effort to minimize outage length, we constructed a two-level, load-bearing, structural, scaffold to provide two access points to the equipment, so work on the motors and pumps could occur concurrently instead of in sequence.

13.8 kV Distribution System. The initial LCM/EPU Program cost estimate included limited modifications to the plant's existing 4 kV electrical distribution system. However, as the Program's detailed design and engineering phase advanced, the Company decided to replace the reactor feed pumps and motors with larger capacity equipment to meet the operational and uprate needs of Monticello. In addition, the existing 4 kV system provided inadequate margin for long-term operation of the plant and needed to be supplemented to provide adequate on-site power for the extended license period. The Company determined that upgrading the plant's non-safety-related equipment to a new 13.8 kV electrical distribution system was the preferred option for meeting the electrical needs of this new equipment. The 13.8 kV upgrade led to initial costs increases associated with the revised scope in the range of about $25 million.

In addition, we incurred about $73 million in installation costs for this modification. This was by far the most difficult project of the whole Program. These costs were incurred because the system had to be constructed in a remote location and the new cable for the system needed to travel through highly-sensitive areas to reach their destination. The design and implementation work packages for this job required careful analysis through an iterative process to ensure safe installation. The Company encountered design challenges to route the conduit and raceways and design issues in the switchgear room. We installed more than 14 miles of five-inch cable in raceways throughout the station. If cables are not carefully installed, they can be damaged by overstress or tensioning. To accommodate these considerations, we pulled the cables in a slow and methodical fashion using 20-foot intervals. In addition, just as the condensate demineralizer system was installed in a highly radioactive space, the cable and conduit for the 13.8 kV electrical system was installed in a very precarious electrical area in the switchgear room. We took many steps to assure worker safety and nuclear safety by constructing shields, requiring tethers for tools, and requiring protective gear, all of which slowed the productivity of the work effort. To understand the scope of this modification, as we approached the outage we estimated that it would require over 183,000 hours (equivalent to 7,625 days) to install the system. The installation of this modification actually required 230,576 hours during the 2013 outage.

Licensing. We also experienced a number of difficulties related to the NRC licensing process. The NRC's review has evolved substantially over the past five years resulting in a substantial increase in our licensing costs and extended the time required to obtain approval of our request. This drove our costs up by about $30 million.

D. Installations

Installation of the modifications took place during our regularly-scheduled refueling outages. The installations occurred during each of the 2009, 2011, and 2013 outages.

1. 2009 Installations

The 2009 refueling outage was scheduled for 45 days. It took 56 days and more than had initially been estimated. We succeeded in installing several important modifications, including replacing the High Pressure Turbine, installing a Power Range Neutron Monitoring Device ("PRNM") and undertaking other modifications necessary for future work. While the outage went somewhat over budget, the issues we encountered were generally of the type that can be expected during a major nuclear outage. We were generally satisfied with the performance of our internal and external teams, which were able to resolve the difficulties that arose. In particular, we worked constructively to address the critical path issues in the outage –

turbine/generator alignment and condenser work – to minimize the added scope to the outage.

2. *Adding the Third Outage*

In light of our relatively successful experience in 2009, we concluded that the internal and external team we assembled to complete the 2009 outage should continue through to the installations in 2011. We believed at that time that the same approach would work well for the 2011 outage. However, several things happened between the 2009 and 2011 outages that impacted on the overall success of the Program.

By summer 2010, our design work for the 2011 outage progressed to the stage where we realized that there was more work to be done than could be accomplished during a single outage. We concluded that if we tried to implement all of the identified work in a single outage, it would have extended the outage through the summer peak demand period. We concluded that we wanted to avoid this risk and that it was better to split the work into two outages.

The primary work that was deferred was the installation of the 13.8 kV distribution system. By deferring this work, it became necessary to also defer upgrades to the reactor feed pumps and motors and condensate pump and motor. The new motors were designed to operate on the 13.8 kV distribution system, and without installing the 13.8 kV system, it was impossible to operate the new pumps and motors.[7]

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[7] Initially we planned to proceed with a second mid-cycle outage in the fall of 2011 for the final installations. We subsequently revised these planning assumptions to 2012, and later to the spring 2013 refueling as a result of the delayed NRC approval and the performance of one of our fabrication vendors. Since our NRC amendment remained suspended at this time, we concluded that the delay in final installation was manageable and appropriate.

3. 2011 Installations

The 2011 refueling outage was scheduled to last 65 days, however, the modifications were completed in 81 days. The extra 16 days for the outage drove up our costs; the primary reason for the delay was the difficult installation of the condensate demineralizer system.

This outage was made more difficult by concerns about design and installation challenges. It required greater site involvement as well as changes in design engineering firms. We experienced recurring difficulties attracting and retaining qualified labor for the installations. And as discussed earlier, we discovered emergent issues during our replacement of the condensate deminineralizer system that lengthened the outage. We worked hard to minimize this impact and implemented creative testing protocols that mitigated the delays.

4. Program Restructure

After the end of the 2011 outage, we decided to restructure the Program to capture the benefits of lessons learned from the outage. Based on the modifications scheduled for the 2013 outage, we still had the most challenging part of the work ahead of us. As a result, we elected to restructure the Program implementation.

First, we hired Bechtel to act as our primary installation contractor for the final installations. Bechtel has a positive track record with implementing LCM and EPU projects. With the magnitude of work left to be accomplished during the 2013 outage, it was a good decision to hire a company of the size and sophistication of Bechtel. This choice was instrumental in our ability to complete all of the complex installations necessary to bring the Program to a successful conclusion.

Second, we restructured the projects organization within the Nuclear department. The most notable change we made was to hire a new Vice President of Nuclear Projects with targeted experience in managing the implementation of large and sophisticated construction projects. The Company also set up a new system of daily and weekly meetings designed to ensure transparent communication of issues and a real-time understanding of how and why costs are being incurred.

5. 2013 Installations

Despite the changes we implemented as part of the restructuring, the 2013 outage was challenging and expensive. It lasted 139 days, which was 52 days longer than scheduled.

During this outage we installed the most difficult equipment modifications, including the 13.8 kV system, the reactor feed pumps and motors, the remaining feedwater heaters and the condensate pumps and motors. The critical path item generally contributing to the 2013 outage duration for the reactor feed pumps and motors replacement, primarily due to the lack of space to complete the work. We expected the work space to be tight and built structural load bearing scaffolding to add work space so we could access two levels simultaneously. Nevertheless, the construction and installation of the building pipes to the nozzles, and the cable pulling to connect power to the pump motors were two activities associated with the feed pump replacement that were especially time-consuming and contributed to cost and schedule overruns during the outage.

Also, he NRC's "fatigue rule" limited the number of hours worked at a nuclear site. This put us at a competitive disadvantage with non-nuclear construction projects, as some workers prefer to take jobs that do not limit the number of hours they can work.

6. Conclusion of Construction

Upon conclusion of the 2013 outage, the Company restarted the plant and all of the new equipment was fully tested and is operating properly at the 600 MW power level. Once the EPU license is granted we expect to begin the power ascension procedures.

E. Standard

We respectfully request that the Commission consider our actions and decisions in the context of the overall Program and in light of the information we had at the time decisions were made. We believe the focus of the inquiry should be on the decision-making process and the reasonableness of our choices at the time, rather than on the outcome. If, in hindsight, an investment is more expensive than predicted or more expensive than other alternatives that had been considered at the time, should not be the focus of the Commission's prudence analysis. If more than one course of action was reasonable at the time a decision was made, the prudence of that decision should focus on the reasonableness of the choice, rather than whether, in hindsight, the other decision may have been preferable.

We also recommend that the Commission apply this standard in assessing our implementation of this highly complex Program. That inquiry should include assessing the Company's reaction to adverse events and ability to adapt as circumstances changed. Specifically, we ask the Commission to understand that many of the complexities did not arise until after the Program started, requiring us to adapt.

As the scope and cost of this Program escalated, we learned many valuable lessons and adapted our processes to meet those evolving circumstances. That a project experiences difficulties is not evidence of imprudence nor is revising practices and procedures to address those difficulties. Rather, adapting in response to lessons-learned is evidence of prudent management that demonstrates our commitment to do our best under challenging circumstances.

V. ACCOMPANYING TESTIMONY

In support of this filing, we have included the prefiled Direct Testimony of a number of witnesses who can describe the scope of the Program. These testimonies are:

- *Timothy J. O'Connor* – Chief Nuclear Officer and Project Champion. Mr. O'Connor has been actively involved with the LCM/EPU Program from its early days and provides context along with the detail of the development and implementation of the Program;

- *Scott L. Weatherby* – Vice President, Nuclear Finance and Business Planning. Mr. Weatherby provides the accounting database and related materials that will allow the Commission and stakeholders the ability to review the detail of the costs incurred;

- *James R. Alders* – Regulatory Consultant. Mr. Alders provides the historical context around the Program, a discussion of the relevant certificate of need and resource planning proceedings, and the Strategist modeling work that was done to support this filing; and

- *J. Arthur Stall* – Retired Chief Nuclear Officer, Florida Power & Light. Mr. Stall brings a wealth of experience in the nuclear business, including having overseen eight nuclear units with LCM/EPU initiatives at four of them. He provides his perspective on the appropriateness of our scope and designs and his opinions about how the challenges we experienced and the outcome of our initiative compares to his own work.

This testimony and accompanying materials will provide the Commission with a substantial record from which to judge the Program.

VI. CONCLUSION

Xcel Energy appreciates this opportunity to provide the Commission, its investigator, the Department and other stakeholders with information about the Monticello LCM/EPU Program. Implementation of this Program was more expensive and took longer than we anticipated. Nevertheless, despite the many challenges we encountered, the upgrades at Monticello were important to the long-term viability of this generating resource. The installation was done right. The equipment is functioning properly and we have had very few issues since the unit returned to full power after the outage. This experience has not been universal. While we acknowledge that our actions were not perfect over the past eight years and we learned many lessons along the way, our efforts were prudent and designed to implement the Program in good faith based upon what we knew at the time. Xcel Energy respectfully requests that the Commission find our actions prudent and that the costs incurred in support of the Program are eligible for recovery in rates.

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Respectfully submitted,

By /s/

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