Direct Testimony and Schedules
Timothy J. O'Connor

Before the Minnesota Public Utilities Commission
State of Minnesota

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
Exhibit___(TJO-1)

Program Oversight

October 18, 2013

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I. INTRODUCTION AND BACKGROUND

Q. WHAT IS YOUR NAME AND OCCUPATION?

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present and support the Company's prudent implementation of the Life-Cycle Management ("LCM") and Extended Power Uprate ("EPU") program (the "LCM/EPU Project," "LCM/EPU Program," "Program," or "Project") at Monticello. I will also introduce the Company's other witnesses in this matter.

II. EXECUTIVE SUMMARY

A. Overview of Initiative

Q. PLEASE PROVIDE AN EXECUTIVE SUMMARY OF THE OVERALL LCM/EPU PROJECT INITIATIVE AND THE PURPOSE FOR THIS FILING.

A. The Monticello LCM/EPU Program was a complex project undertaken to prepare Monticello for its 20-year extended operating life at increased capacity of 671 megawatts ("MW"). The Program spanned roughly eight years and involved the replacement of hundreds of pieces of equipment inside the plant. We replaced nearly all of the components that support the reactor and power generation equipment. Because this Program was implemented in an operating nuclear facility, I believe that from a design and implementation perspective, it was even more challenging than the original construction of the plant.

We employed thousands of workers during each of three implementation outages (2009, 2011, and 2013). At all times during this Program we placed the safety of our workers, customers and surrounding communities as our top priority. All of our decisions were made with this primary consideration in mind.

The uprate portion of the Project was conceived and initiated in conjunction with the 20-year license renewal we received from the Nuclear Regulatory Commission ("NRC") in 2006. At that time, we were evaluating and planning investments necessary to ensure Monticello's safe and reliable operations through 2030. We knew then that the NRC had approved several other uprate projects.

Simultaneous with our license renewal planning, in 2006, our demand forecast showed a critical need for additional baseload capacity, and natural gas and renewable prices were relatively high. We chose to multi-track the LCM/EPU Project, and proceeded with the licensing, design, engineering and implementation phases simultaneously to meet the projected demand, achieve the full value of the projected energy savings, and optimize our life extension investments. We recognized that if we did not proceed with these phases concurrently, we would not be able to deploy the additional capacity to meet the demand growth forecast during the 2004-2007 timeframe and projected to continue.

We also recognized there was some risk in pursuing the multi-track approach because we were not assured of obtaining all of the authorizations necessary to increase the capacity. We were confident the Minnesota Public Utilities Commission ("Commission") would grant a certificate of need based upon the Commission's June 2006 Order in our 2004 Resource Plan Docket (E002/RP-04-1752) approving the Monticello EPU as part of the Company's preferred plan. We also were confident that based on past industry experience, and the NRC's stated policy of deciding these matters in one year to 18 months, that this work was appropriate. At the time the Commission approved the LCM/EPU Program in January 2009, we anticipated receiving the NRC's approval by 2010, and planned to implement the Program during the 2009 and 2011 refueling outages and ascend to uprated operations in mid-2011. We began our first implementation phase within two months of receiving the certificate of need. Company witness Mr. James Alders describes the resource planning environment that influenced our decisions and timing.

Projects of this magnitude and complexity often encounter difficulties and challenges related to the final scope, and nuclear projects face evolving regulatory requirements. The LCM/EPU Program took longer and cost significantly more than we originally anticipated. We incurred approximately $665 million, roughly double our initial estimates, to complete the Program.[1] The nuclear industry experienced a number of significant events between the initiation of the Program in 2006 and the final implementation of the Program in 2013. Consequently, our federal licensing requirements have increased and we attempted to respond to these evolving concerns in our decision-making.

Primarily, we decided to expand the initial Program scope and accelerate other work to ensure adequate safety and operating margin to meet the regulatory requirements that will be in place through 2030. To Accomplish the necessary scope additions, we required significant design modifications to our high-level conceptual designs used in our certificate of need proceeding. In the end, four major modifications ended up causing the bulk of the cost increase. Our costs for these modifications and their initial estimates are summarized in Table 1 below.

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[1] For purposes of this proceeding, Xcel Energy will use the August 31, 2013, actual amount spent, of approximately $665 million, as the basis for our presentation. We currently forecast approximately another $5 million to obtain the final license approvals and implement the EPU once the license is granted.

I also note that Xcel Energy will be filing a general rate case in November 2013. In that rate case, Xcel Energy will include approximately $655 million in our 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, prior to the completion of the 2013 outage. 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.

Table 1. LCM/EPU– Major Scope Additions

MODIFICATION	MILLION $	
	2008 ESTIMATE	ACTUAL COST
13.8 kV System Addition	20.9	119.5
Condensate Demineralizer System Replacement	18.0	79.8
Feedwater Heater Replacement	37.0	114.9
Reactor Feed Pump Replacement	27.8	92.2
Total	103.7	406.4

Each of these four upgrades was needed to restore or improve safety and operational margins that had eroded after 40 years and to operate the facility at uprated conditions. While we incurred more costs than our original estimates for those modifications, several modifications went smoothly. The steam dryer, turbine, and power range neutron monitor modifications were examples of major modifications implemented within or near our originally estimated costs.

As we increased the Program scope, the magnitude of the installation also grew. Our implementation efforts accounted for nearly $290 million of the Program costs, which we substantially underestimated. As we will explain, these modifications to the secondary system, even when the plant is off-line, are complex and intricate, and require specialized labor, tools and safety procedures. Some of the components and systems we replaced are located in radiological areas, infrequently accessed during normal plant operations. We faced a number of vendor and labor challenges and the productivity during implementation was less than we anticipated due in part to the challenging working conditions encountered. In devising our initial estimate, we underestimated the scope of work required and the complexity of the installation work, and as a result, we incurred costs well beyond our initial expectations. Our costs incurred by category are summarized in Table 2.

Table 2. Cost Categorization*

	Actual Cost (million $)	% of Total
Licensing-Related	$62.1	9%
Design/Engineering	$158.8	24%
Materials/Components	$146.5	22%
Installation	$288.6	43%
Xcel General Costs	$8.8	1%
Total[2]	**$664.9**	**100%**

*With Common Cost Allocated

The NRC's review of our license application has taken approximately four times longer and cost approximately twice as much as we originally expected. The NRC's review is necessary to assure the safety of our operations and we fully support the NRC's mission in this regard. Indeed, in certain instances we were on the cutting-edge of the industry by developing new analytical techniques to support the NRC's approval. As a result of our substantial efforts, we received approval from both the subcommittee and full Advisory Committee on Reactor Safeguards ("ACRS") on July 25-26, 2013, and September 5, 2013, respectively, and we anticipate receiving the NRC's final uprate approval by the end of 2013.

Once we receive the EPU license amendment, we will begin ascending to the higher power levels authorized by the amended license. Until we receive the second license amendment for the fuel configuration ("MELLLA+") we will

[2] The total includes roughly $88,000 remaining in the common cost category that was not allocated to the functional cost categories.

be able to ascend to approximately 640 MW.[3] We expect to receive NRC approval to operate using the MELLLA+ procedures in March 2014.

Despite the design, implementation and licensing challenges, we believe the Monticello facility is safer and more reliable as a result of our investments. Modifications such as our replacement of the reactor feed pumps and motors with larger, more powerful pumps and motors, and our addition to the electrical distribution system of a higher-capacity 13.8 kV system, will allow us to operate the plant with substantially higher operating and safety margins, and provide sufficient capacity to sustain electrical loads as regulatory requirements evolve in this post-Fukushima era. We will demonstrate that our decisions related to these substantial scope changes and implementation challenges were both reasonable and prudent, and resulted in substantial benefits to our customers.

As the Program scope changed during the detailed design phase in 2007 we generally did not foresee that the changes we made would drive the level of cost increases experienced. In retrospect, it seems apparent the Program was going to cost much more than we had forecast, but at the time we began the Program, the final costs were not evident. We were looking backward for others' experience, while the world ahead of us was changing rapidly. While I believe that we engineered the appropriate modifications with solid and innovative design features, I think we may have done a better job foreseeing a portion of the increase. Even if we had done a better job, however, I am certain that we would not have forecast anything approaching the ultimate

[3] This fuel configuration is called the MELLLA+ amendment request, which stands for "Maximum Extended Load Line Limit Analysis." MELLLA+ is an engineering analysis that provides for greater operational flexibility, permits more efficient reactor startup, maximizes fuel utilization and improves fuel cycle economics.

Program cost. For example, we continually reevaluated our estimate for the 13.8 kV system. Our preliminary estimate for this project began at roughly $20 million and soon increased to roughly $30 million. Even our last estimate prepared before the final outage was far lower than the actual cost of nearly $120 million incurred to complete the 13.8 kV modification. And yet, were not alone in our inability to project the materiality of the costs of the Program. We will explain that other utilities faced similar levels of cost increases over their initial estimates that we confronted.

Finally, it is critical to consider the importance of the Monticello facility to our system. The Program combined important LCM projects with the uprate. We determined the substantial majority of the work (78 percent) needed to be done for LCM in the near term. As I will explain in Section IV, it was more cost-effective and efficient to design and implement the LCM and EPU upgrades to the plant at the same time, so we combined these activities into a single Program. The combination of activities allowed us to maximize the depreciation schedule and avoid significant LCM expenses late in the 20-year extended license life.

Upon completion of the uprate, Monticello will provide over 671 MW of reliable, baseload power with virtually no emissions. Even today, Monticello as a whole is cost-effective and a sound investment for our customers. At a time when the federal government is increasing its regulation of fossil fuel emissions, emissions-free energy sources are an important tool to mitigate potential future environmental compliance costs. In this regard, continued operation of Monticello reduces our CO_2 emissions by approximately 2.8 million tons, or 14 percent, annually compared to natural gas generation.

The LCM/EPU Program investments we made will allow Monticello to serve our customers through at least 2030. We addressed many challenges along the way and are confident the record will demonstrate the reasonableness of our decisions and actions under the circumstances. We are pleased that our work will provide clean, reliable and efficient energy to our customers through 2030 and possibly beyond.

B. Purpose and Organization of this Filing

Q. WHAT IS THE PURPOSE OF THIS FILING?

A. In our 2010 rate case (Docket No. E-002/GR-10-971) and again in our 2012 rate case (Docket No. E-002/GR-12-961), the Company committed to undertaking a prudence review of the Monticello LCM/EPU Program. Our commitment followed concerns related to the increased costs experienced on this project.

While we understand why the Commission is concerned about our cost increases, we believe that a full review of the record of this Program will demonstrate that our key decisions were reasonable in light of the circumstances at the time of the decisions.[4] Thus, to support the Commission and the Department of Commerce, Division of Energy Resources

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[4]While we did not formally address our cost changes in our resource plan (because we continued to believe moving forward was in our customers' interest), we did provide updates of our costs in our 2010 and 2012 rate cases. In the first case, we provided an initial test year budget forecast of $400 million based on the information available at that time. Later in that rate case, after the 2011 outage had occurred, we updated the projection to approximately $450-$500 million. As that case was finishing and we were working toward our 2012 rate case, we did substantial work at refining the costs and developed a new estimate of approximately $585 million. During the 2012 case we worked through detailed project work packages and provided a revised estimate of $640 million. We believed this discussion of these changes to our cost estimates was an appropriate means of keeping the Commission and parties updated.

("Department") in their review of the Project, we are making this initial filing to provide a detailed review of the Project, our decisions and our costs. Our initial filing addresses the following topics:

- The Company's nuclear program, NRC regulation, and relevant industry experience with major nuclear upgrades;
- The total cost of the LCM/EPU Program and an analysis of the key cost drivers;
- The history of the Program's initiation and the nature of the original scope, schedule and estimate;
- The EPU licensing process;
- The planning and execution of the LCM/EPU Program implementation outages and the major modifications completed;
- The reasonableness of the Company's key scope changes and schedule;
- The steps taken by the Company to manage vendor issues, quality concerns and evolving scope; and
- The benefits and cost-effectiveness of the LCM/EPU Program.

The Company is providing the testimony and exhibits of four witnesses in its direct case. In addition to myself, the Company is sponsoring the following witnesses in this proceeding:

Scott L. Weatherby. Mr. Weatherby is the Vice President-Finance for the Company's nuclear department. His testimony provides a detailed description and method of accounting for the costs incurred in connection with the Program;

James R. Alders. Mr. Alders is responsible for resource planning and was actively involved with the Minnesota regulatory processes that informed the Company's nuclear strategy. His testimony discusses the certificate of need processes relevant to this proceeding. His testimony also discusses a variety of resource planning and cost-effectiveness considerations both at the time we commenced the Program and at the present time. These analyses support the fact that the Company made prudent economic decisions both when it undertook the Program and in each subsequent year; and

J. Arthur Stall. Mr. Stall is the recently-retired CNO of NextEra Energy and the Florida Power and Light ("FPL") system. In his role at NextEra, Mr. Stall was responsible for more than 6,000 MW of nuclear generation, and he oversaw four EPUs implemented in Florida in 2011 and 2012. His expert testimony provides context for the Company's decisions and describes the challenges that are encountered in major nuclear initiatives of this type. Mr. Stall concludes the Company developed a reasonable design for its Program and the scope of work completed was necessary. He concludes that the Program costs were reasonable under the circumstances and in comparison with what he encountered with his prior EPU experience.

We believe that this information will provide the detailed information necessary for a complete review of our project, and we look forward to the opportunity to assist the Commission and the Department in gaining a full understating of our initiative.

III. XCEL ENERGY'S NUCLEAR PROGRAM

Q. HOW ARE YOU STRUCTURING THIS SECTION OF YOUR TESTIMONY?

A. I introduce the Company's nuclear program and the Monticello plant. I then provide an overview of the NRC and its regulatory authority, and a discussion of nuclear uprates. Nuclear power is highly complex subject matter that includes many technical issues and terms. To assist the Commission in its review, I am providing a list of acronyms that may be useful to stakeholders in Exhibit ___ (TJO-1), Schedule 2.

A. Xcel Energy's Nuclear Program

Q. IS XCEL ENERGY COMMITTED TO INCLUDING NUCLEAR ENERGY AS PART OF ITS RESOURCE MIX?

A. Yes. Nuclear power is a secure, baseload energy source that is an integral part of our resource mix. Nuclear power plants generate electricity uninterrupted for extended periods – as long as 24 months. Baseload plants provide reliable, low-cost power 24 hours a day, seven days a week. They supply the necessary baseload power for the electricity transmission network, or grid, to operate. Thus, nuclear power is a key element in the stability of the electric grid.

Xcel Energy owns and operates two nuclear power plants comprised of three separate operating units – Monticello near Monticello, Minnesota, and Prairie Island (Units 1 and 2) near Red Wing, Minnesota. Taken together, our nuclear fleet produces 30 percent of the electricity we provide to customers in Minnesota and surrounding states. Our nuclear units are part of America's largest source of clean-air, carbon-free electricity, producing no greenhouse gases. Over the course of their operating lives, our nuclear power plants help us avoid the production of hundreds of millions of tons of greenhouse gases. Including nuclear as a key part of our portfolio provides Minnesota electricity customers significant value in hedging volatile fossil fuel prices.

Q. PLEASE DESCRIBE THE COMPANY'S OBJECTIVES FOR ITS NUCLEAR FLEET.

A. Xcel Energy views its nuclear program as an integrated fleet. We received license renewal for each of our three units, allowing us to continue providing our customers with baseload energy into the 2030s. Our goals for operating them during the license renewal period are relatively simple. We strive to keep our nuclear plants operating safely, reliably and economically. Safety is an obvious imperative and always has been. The principles adopted specifically for our Monticello plant are provided in Exhibit ___ (TJO-1), Schedule 3. We work closely with the NRC and industry peers to ensure that we achieve this objective. We are also committed to improving operational performance of our plants, and the equipment upgrades at Monticello are part of this effort.

Q. IN LIGHT OF THE BENEFITS PROVIDED BY THE MONTICELLO PROGRAM, WHY DID THE COMPANY CANCEL THE EPU PROGRAM AT PRAIRIE ISLAND?

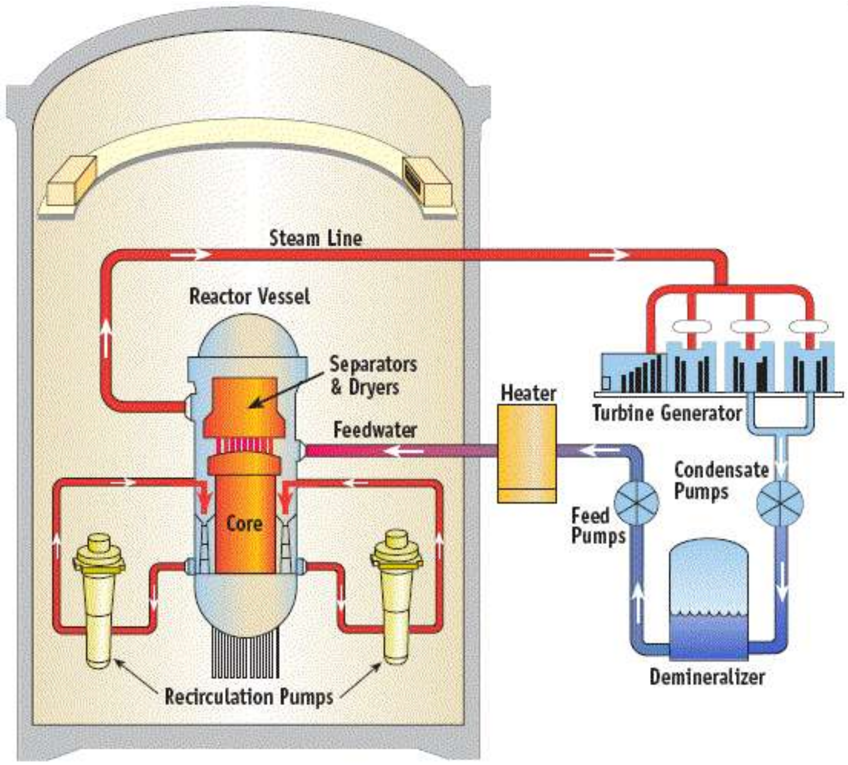
A. We cancelled our EPU initiative at Prairie Island because we projected the capital costs and regulatory risks to increase. In 2011 we believed the NRC would require much more detailed design to approve a license amendment request for the Prairie Island EPU than they had for Monticello. That effort would require years of upfront engineering analysis to prepare the license application. We were also concerned based on Monticello's experience that costs could increase substantially even from more conservative estimates and that there was far less certainty as to whether we would actually obtain an uprate license. Further, the Prairie Island EPU initiative was in its early stages when natural gas prices fell and forecast demand decreased. In contrast, the Monticello LCM/EPU Program was well underway as these economic shifts occurred. These distinguishing features between the two efforts contributed to our decision to terminate the Prairie Island EPU initiative while continuing with the Monticello LCM/EPU.

B. Monticello

Q. PLEASE DESCRIBE THE MONTICELLO PLANT.

A. Monticello is currently a 600-MW, nuclear-powered, boiling water reactor ("BWR"), electric generating plant located in Monticello, Minnesota. It produces electricity by boiling water through nuclear fission and producing steam. The steam is directly used to drive a turbine, after which it is cooled in a condenser and converted back to liquid water. Figure 1 is a schematic drawing of the major components of a nuclear power plant that utilizes a BWR like Monticello.

Figure 1. Boiling Water Reactor Systems



Nuclear fuel assemblies reside in the reactor and supply heat to generate steam for about six years at the Monticello plant. Once fuel is discharged from the core, it becomes spent nuclear fuel. Monticello is shut down approximately every two years to refuel. During each refueling outage about one third of the fuel assemblies are removed from the reactor and replaced with new assemblies. Refueling outages are also very important to the life-cycle of nuclear power plants. Xcel Energy coordinates maintenance and capital upgrades with its refueling outage schedule to minimize outage time. By combining maintenance and capital upgrades, we minimize overall disruptions to plant operations.

Q. WHAT IS THE DIFFERENCE BETWEEN A BWR AND A PRESSURIZED WATER REACTOR ("PWR")?

A. In a BWR, such as Monticello, the reactor core heats water, which turns to steam and then drives a steam turbine. By contrast, in a PWR, such as Prairie Island, the reactor core heats water, but the water is prevented from boiling by maintaining higher pressure in the reactor. This hot water then passes through large heat exchangers, known as steam generators. The steam generators also contain a separate low pressure water supply that is converted to steam and that steam drives the turbine and generator. These differences lead to differences between LCM work required at each type of facility.

Q. WHAT TYPE OF SERVICE DOES MONTICELLO PROVIDE TO THE COMPANY'S CUSTOMERS?

A. Due to the nature and economics of a nuclear power plant, Monticello is operated at full capacity whenever it is available. From 2008 through 2012, Monticello maintained an average capacity factor of 88.8 percent. In 2012, the Monticello plant produced 4,890,374 MW-hours ("MWh") of electricity, or about 10 percent of our customers' annual electric energy requirements.

C. Nuclear Overview

1. *Overview of Licensing Requirements*

Q. BY WHAT AUTHORITY IS XCEL ENERGY AUTHORIZED TO OPERATE MONTICELLO?

A. The NRC regulates the operation of nuclear power plants. Xcel Energy obtained a 40-year operating license from the NRC in 1970. In 2006, the NRC renewed our operating license through 2030.

Q. WHAT ARE THE LIMITATIONS ON MONTICELLO'S OPERATIONS?

A. Monticello's operating license contains detailed parameters for operation of the plant. When the NRC issues a license for a commercial nuclear power plant, the agency sets limits on the maximum heat output, or power level, for the reactor core. This thermal power level plays an important role in many of the analyses that demonstrate safety of the plant. The NRC's permission is required before a plant can change its maximum power level.

Q. PLEASE DESCRIBE THE NRC'S ROLE IN MAINTAINING NUCLEAR SAFETY.

A. The NRC is responsible for overseeing the safe operation of nuclear generation facilities. The NRC regulates the radiological, engineering, health and safety standards applicable to operating the Monticello plant. Therefore, the Company must apply for and receive an amendment to Monticello's operating license from the NRC prior to making any changes to the licensed design basis of the plant. The regulatory approval process to amend a nuclear facility's operating license and technical specifications is governed by Title 10 of the Code of Federal Regulations ("CFR"), Part 50.

Public health and safety is the fundamental goal underlying all NRC actions. The NRC has long recognized the importance of a safety-first focus in nuclear work environments for public health and safety. This nuclear safety culture is defined as the core values and behaviors resulting from a collective commitment by leaders and individuals to emphasize safety over competing goals to ensure protection of people and the environment.

Q. DOES A RENEWED LICENSE FROM THE NRC REQUIRE THE COMPANY TO COMPLY WITH A VARIETY OF TECHNICAL REQUIREMENTS?

A. Yes, as a condition of obtaining the renewed license, Xcel Energy must comply with, among other things, the following four rules designed in part to ensure that reactors and plant systems remain safe for the duration of the license.

- Corrective Action Program
- Aging Management Rule
- Maintenance Rule
- Back Fit and Forward Fit

Taken together, all of these requirements place an obligation on the operator to ensure the facility is designed appropriately to meet the relevant design criteria and that it will meet all applicable safety requirements for the entire duration of the plant's operating license. These NRC requirements are discussed in more detail the Direct Testimony of Company witness Mr. J. Arthur Stall.

Q. AT THE TIME IT WAS SEEKING A LICENSE RENEWAL, DID THE COMPANY FORESEE THE MAGNITUDE OF THE SYSTEMS THAT WOULD NEED TO BE REPLACED AS A RESULT OF THESE OR OTHER NRC REQUIREMENTS?

A. Not entirely. As we investigated the license renewal we recognized some systems would need to be replaced but did not fully appreciate the amount of work that was required. After further analysis of the existing plant equipment, we identified a number of important systems that ultimately needed to be replaced or modified, including: replacement and updates to the generator and turbine systems, replacement of the main power transformer, replacement of the feed pumps, replacement of the condensate pumps, and improvements to the condensate demineralizer system. As we moved through the process we identified the need to replace the entire condensate demineralizer system, all six feedwater heaters and the steam dryer. Finally, we made a decision to increase the capacity of Monticello's electric distribution system to 13.8 kV. Many of the systems we identified during our license renewal process are the same modifications we implemented in connection with the LCM/EPU program. Though we ended up replacing more balance of plant systems in the LCM/EPU program than we anticipated initially, all of the work was consistent with the overall goal of ensuring that the plant maintain safe and reliable operations through the license renewal period.

2. Overview of Uprates

Q. WHAT IS AN EPU?

A. A power uprate occurs when a nuclear power plant increases its maximum output. An EPU is the most significant type of uprate because it requires a greater number of physical modifications to the plant. In a BWR such as Monticello the generation of additional power requires the production of additional heat and steam which requires correspondingly more robust systems to ensure that the plant can produce the additional power safely. I have attached a copy of the NRC Backgrounder on Power Uprates for Nuclear Plants as Exhibit ___ (TJO-1), Schedule 4.

Q. HOW ARE EPUS INSTALLED AND IMPLEMENTED?

A. Implementing the EPU generally requires that we design and install modifications to the non-nuclear side of the station that will operate safely in light of the added heat and steam. Although most of the work is done to the non-nuclear side or balance of plant, the design and installation of modifications to the nuclear plant present special challenges.

The types of modifications required to implement an EPU as well as many LCM upgrades cannot be undertaken while the plant is in operation. Some of the installations require access to areas with high radioactivity that can only be accessed when the plant is off-line. In addition, the systems required to be installed are often integral to the safe operation of the plant and work on those systems requires the plant to be shut down.

Nuclear plants must be taken off-line for periodic refueling. Because of the premium on maintaining maximum availability of nuclear plants, we try to minimize the frequency and length of outages. During refueling outages we try to conduct maintenance, repairs and capital upgrades necessary for ongoing safe operations. In the case of the LCM/EPU Program, we initially planned to coordinate major construction projects with our regularly scheduled refueling outages in 2009 and 2011. As the scope of the project grew, and we encountered difficulties with both equipment and design, we revisited the schedule and completed a substantial portion of the work during the 2013 refueling outage. I will describe the outage process in more detail later in my testimony.

3. Overview of Monticello Program

Q. WHY DID XCEL ENERGY DECIDE TO PURSUE AN EPU?

A. Xcel Energy chose to proceed with the EPU at Monticello as part of our overall effort to operate Monticello through 2030. Monticello achieved a 6.3 percent uprate in 1996-1998, and that project went well. Further, at the time we decided to proceed with Monticello's EPU in 2006, we recognized that other utilities had positive experiences both in obtaining NRC approval to proceed as well as in the overall costs of their initiatives.

Q. WHAT WERE THE MAJOR PIECES OF EQUIPMENT THAT WERE INSTALLED AS PART OF THE PROGRAM?

A. The overall Program was comprised of almost 40 separate work orders or individual projects. Ten major modifications comprised nearly the entirety of the LCM/EPU Program and about 95 percent of its costs. The ten major modifications include:

(1) High-Pressure Turbine Replacement and Low-Pressure Turbine Modifications,

(2) Power Range Neutron Monitoring System Replacement,

(3) Steam Dryer Replacement,

(4) Condensate Demineralizer System Replacement,

(5) Main Transformer Upgrades,

(6) Feedwater Heaters Replacement,

(7) Reactor Feed Pumps and Motors Replacement,

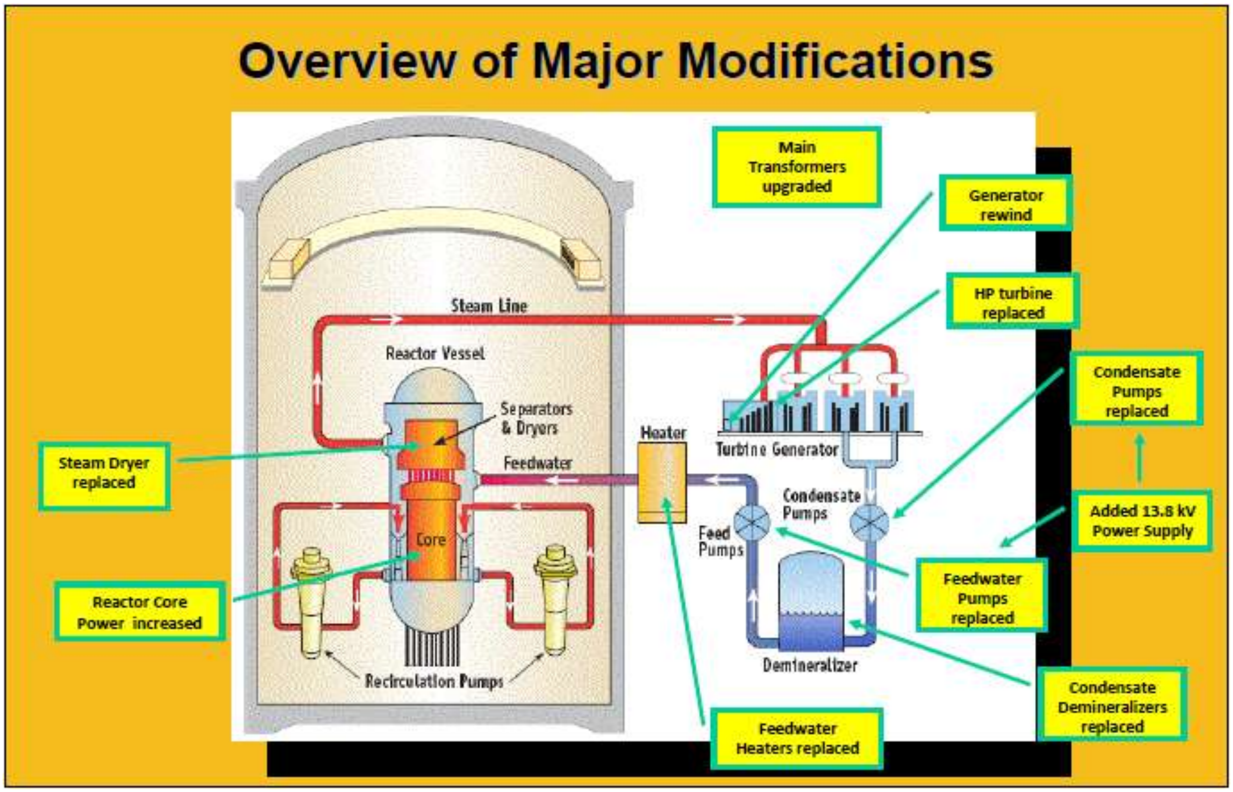
(8) Condensate Pumps and Motors Replacements,

(9) Upgrade of the 4 kV electrical distribution system to 13.8 kV, and

(10) NRC EPU and MELLLA+ Licensing Costs.

Figure 2 graphically depicts the major modifications that were implemented as part of the Program.

Figure 2. Major Modifications at Monticello



A description of all Project modifications, the in-service dates, costs and justification for all modifications is provided in Exhibit ___ (TJO-1), Schedule 5. A complete cataloging of these major modifications, including the final costs, the supporting vendors and any challenges encountered, can be found in Exhibit ___ (TJO-1), Schedule 6.

D. Other Uprate and Refurbishment Projects

1. *Early EPU Successes*

Q. WERE YOU AWARE OF EPUS CONDUCTED AT OTHER PLANTS BEFORE 2006 WHEN YOU DECIDED TO PURSUE THE CURRENT LCM/EPU PROGRAM?

A. Yes. By 2006, the NRC had approved 108 uprates. Of those approved uprates, 13 were EPUs, including EPUs at the Duane Arnold, Dresden and

Quad Cities nuclear facilities. Beginning with the approval of Monticello's EPU in 1998, the NRC approved 12 EPUs for BWRs through 2007. On average, the NRC's review and approval of these EPU's took approximately one year and two months.

Q. DID XCEL ENERGY TRACK THE PROGRESSION OF THESE PREVIOUS UPRATE PROJECTS?

A. Yes. Throughout the initial preparation of the Program we completed due diligence on the other EPUs that were approved prior to 2006. We considered available EPU operating experience, regulatory issues found in transcripts and NRC notices and areas of review contained in NRC Review Standard RS-001 (the review guidance document applicable to EPU applications). Xcel Energy's project team also reviewed NRC inquiries and responses for previous EPU processes to identify the industry issues that concerned the NRC Staff. We then considered which of those issues should be addressed in our application.

Q. AT THE TIME XCEL ENERGY WAS CONSIDERING WHETHER TO PROCEED WITH AN EPU HAD OTHER UTILITIES EXPERIENCED DELAYS IN RECEIVING NRC EPU APPROVAL?

A. Several plants, including the Dresden, Quad Cities and Duane Arnold plants all proceeded through the regulatory process shortly after our initial EPU experience in 1998. As noted above, all of those plants obtained the required license amendment without excess delay or complication. When, in 2005 and 2006, we were considering a second EPU at Monticello, the track record of relatively smooth approval processes suggested to us that obtaining uprate approval would not be unduly complicated.

2. *Recent Uprate and Refurbishment Experiences*

Q. HOW DOES XCEL ENERGY'S LCM/EPU PROGRAM EXPERIENCE COMPARE TO OTHER UPRATE PROJECTS WITHIN THE NUCLEAR INDUSTRY?

A. We were not alone in our inability to accurately estimate the cost and schedule of the LCM/EPU Program. Table 3 is a listing of the recent cost and schedule experiences of other utilities with the implementation of EPUs and other life cycle initiatives. As shown below, many other recent nuclear capital initiatives in the U.S. and Canada experienced costs double their initial estimates and schedules twice as long.

Table 3. Cost Increases and Schedule Changes

Project	Description	Initial Cost Estimate	Latest Cost Estimate	Initial to Final Cost	Estimate of Schedule Extension	Year Completed
Grand Gulf	EPU	$420-$500 million	$874 million	1.7-2.1	n/a	2012
Turkey Point and St. Lucie	4 EPUs	$1,398 million	$3,129 million	2.2	1 year	2011, 2012, 2013
Cooper	EPU	$289 million	$409 million	n/a	Suspended	n/a
Bruce A, Units 1 & 2	Refurbishment and Restart	C$2.75 billion	C$4.8 billion	1.7	2 years	2012
Point Lepreau	Refurbishment	C$1.4 billion	C$2.4 billion	1.7	3 years	2012
Susquehanna	EPU	$217 million	$345 million	1.6	2 years	2010, 2011
Monticello	LCM/EPU	$320-$346 million	$665 million	1.9-2.1	2 years	2013

All of these recent projects place our experience in line with a rapidly evolving industry.

Q. BASED ON THIS CHART, SOME OF THESE PLANTS FARED SOMEWHAT BETTER THAN MONTICELLO. CAN YOU EXPLAIN THAT?

A. Yes. While we do not have comprehensive knowledge of all such projects, we are confident that the scope of work at Monticello was greater than at the other EPU projects. For example, I am familiar with the scope of work required for the Susquehanna EPU. This cost involved two units and the scope was substantially less than the scope of work required for Monticello's LCM/EPU Project. For example, the Susquehanna EPU did not include upgrades to the facility's electrical distribution systems or replacement of the facility's reactor feed pump or transformers.

Q. DOES THE COMPANY PROVIDE AN ASSESSMENT OF THE LCM/EPU PROGRAM IN COMPARISON TO OTHER NUCLEAR UPRATE PROJECTS IN THIS FILING?

A. Mr. Stall, evaluates the Monticello LCM/EPU Program against several projects he oversaw as CNO for FPL and concludes the Program developed along schedule and cost timelines that were similar to other complex nuclear projects.

As I briefly introduced, Mr. Stall is the recently retired CNO for FPL, and he oversaw the life extension and EPU projects at the Turkey Point and St. Lucie nuclear facilities. Collectively, the FPL EPU projects exceeded their initial estimates by more than two-fold, or approximately $1.7 billion. The Florida Public Service Commission reviewed FPL's implementation of the uprate projects in annual prudence reviews from 2009 through 2013. The Florida Commission determined the cost of the projects were prudently incurred, and it authorized full recovery of the uprate costs of $3.1 billion.

In his testimony in this proceeding Mr. Stall describes the challenges facing the nuclear industry in pursuing these programs, including recent industry events, the evolution of the NRC regulation and the increasing difficulty in work force management in connection with major capital projects like Monticello's LCM/EPU program. In his professional opinion, Mr. Stall concludes that:

- The design basis for both the life extension and uprate aspects of the LCM/EPU Program were selected and implemented with nuclear safety in mind and in compliance with NRC requirements,
- The chosen design basis was both logical and appropriate to meet Xcel Energy's overall goal of maximizing the value of the Monticello plant for its customers through 2030, and
- The incorporation of both the LCM and EPU initiatives into one combined project was appropriate and allowed Xcel Energy to efficiently address and implement the necessary life extension and uprate investments.

IV. PROGRAM COST OVERVIEW

A. Aggregate Costs

Q. WHAT ARE THE LCM/EPU PROGRAM COSTS?

A. In total, the Program incurred total costs of $664.9 million, as of August 31, 2013. For a summary of the total Program costs by modification (or child work order), by year, please see Exhibit ___ (TJO-1), Schedule 7. The information provided in my testimony and schedules refers only to actual Program costs incurred and recorded through August 31, 2013. A summary of when various projects of the EPU/LCM Program were placed into service and justification for the project is provided at Exhibit ___ (TJO-1), Schedule 5.

Q. HOW WERE THE PROGRAM COSTS INCURRED OVER THE COURSE OF THE PROGRAM FROM 2007 THROUGH 2013?

A. As demonstrated below, the majority of the costs were incurred during the 2011-2013 time period. Due to various reasons such as design complications, vendor fabrication issues, the complexity involved in sequencing the implementation activities, and NRC delays, much of the work we hoped to complete during 2011 required completion in 2013. From January 2011 through Program completion we incurred more than $365 million. Of this amount, the substantial majority, more than $230 million, was spent during the 2011 and 2013 installation outages.

Q. WHAT CATEGORIES OF COSTS DID YOU INCUR FOR THE PROGRAM?

A. As shown in Table 4, we incurred costs in five major categories, including design, licensing, equipment and materials, and installation.

Table 4. Cost Categorization (Million $)

Cost Category	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$0.0	$0.0	$0.0	$0.0	$0.4	($0.1)	($0.0)	$50.2	$5.1	$4.6	$60.2
Design/Engineering	$0.0	$0.0	$0.1	$4.0	$3.7	$19.6	$16.1	$73.0	$6.3	$15.2	$138.0
Materials/Components	$0.0	$0.0	$0.0	($0.0)	$0.4	$60.0	$3.0	$24.5	$2.6	$6.0	$96.5
Installation	$0.0	$0.0	$0.0	$0.0	$0.0	$24.1	$7.6	$86.6	$27.9	$117.0	$263.1
Xcel General Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.4	$0.6	$1.4	$0.1	$0.2	$2.7
Common Cost Allocations	$0.8	$0.0	$6.9	$11.7	$69.0	$14.7	$48.8	($61.8)	$5.0	$9.2	$104.4
Licensing-Related	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.4	$0.2	$0.3	$1.9
Design/Engineering	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$13.1	($6.2)	$13.8	$20.8
Materials/Components	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.6)	$32.8	$5.4	$12.5	$50.0
Installation	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.6	$17.8	$9.5	($2.3)	$25.5
Xcel General Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2.8	$0.4	$2.7	$6.0
Total:	$0.8	$0.0	$7.0	$15.7	$73.6	$118.7	$76.1	$173.9	$47.0	$152.1	$664.9

Q. PLEASE DESCRIBE THE COST CATEGORIES YOU REPORT.

A. The five categories in Table 4 represent large functional categories that are helpful groupings for programs or projects similar to the LCM/EPU Program. I note that we did not track this categorization during the Project. Rather, we prepared this categorization to facilitate the Commission's review. These categories are described below:

- Licensing-Related – Costs related to the NRC licensing effort and associated analyses, and other regulatory and legal costs.
- Design/Engineering – Costs incurred by the Company and its vendors to design and engineer the modifications.
- Materials/Components – Costs for materials, components or equipment consumed or installed in the plant as part of the LCM/EPU project.
- Installation – Costs incurred to plan for and install the Project modifications during the implementation outages.
- Common Costs – Overall Project costs, such as project management and other costs not directly assigned to specific modifications.
- Xcel General Costs – Generally, Xcel internal corporate charges, as allocated.

Company witness Mr. Scott L. Weatherby's Direct Testimony explains these common costs in more detail. Exhibit ___ (SLW-1), Schedule 3 and Exhibit ___ (SLW-1), Schedule 6 to Mr. Weatherby's Direct Testimony provide additional detail on how these cost categorizations were derived and how the Company analyzed the costs by category both with and without allocations of the aforementioned common costs. While this exercise does not result in accounting-level precision, it provides useful information about the magnitude of costs incurred in each category.

Q. ARE YOU PROVIDING A RECORD AND TRACKING OF ALL COSTS INCURRED IN THIS PROCEEDING?

A. Yes. Mr. Weatherby provides the accounting of all actual Program costs incurred in his Direct Testimony in this proceeding. In addition, we are providing detailed schedules that report costs by vendor, work order, time period and business unit description, among other categories. We will work with the Commission and Department to ensure a full accounting of cost is available for complete analysis of the record.

B. Initial Cost Estimate

Q. WHAT WAS THE INITIAL PROGRAM COST ESTIMATE?

A. Our EPU Certificate of Need application included EPU costs of $133 million but did not expressly detail the LCM costs. The application included a cost sensitivity analysis that estimated an initial cost range of $320 to $346 million for LCM/EPU activities.

Table 5 compares the cost estimates included in the EPU Certificate of Need application to the actual total Program costs incurred.

Table 5. Comparison of 2008 Certificate of Need Estimate and Actual Program Cost

	2008 Certificate of Need Estimate	Actual
LCM/EPU Costs	$270-293	$499
Steam Dryer	$29-32	$30
13.8 kV System Replacement	$21	$120
GE Project Change Requests	--	$16
Total	$320-346	$665

Q. IS IT CUSTOMARY FOR A NUCLEAR PROJECT TO BE INITIATED USING PRELIMINARY ENGINEERING AND COST ESTIMATES?

A. Yes it is in my experience. Most projects begin with a preliminary level of detail because of the magnitude of costs associated with the detailed design and engineering work necessary to complete a project of this size and the amount of time it takes to complete a major project. Doing so permits a project sponsor to evaluate the feasibility of completing the project while continuing to obtain new and better information. In light of the timing and cost issues, as well as the need to obtain NRC approval for any change in operating parameters, it would be very difficult to complete projects without the use of high-level, conceptual estimates.

C. Cost Drivers

Q. WHY DID THE ACTUAL PROGRAM COSTS EXCEED THE INITIAL $320 MILLION COST ESTIMATE?

A. The reasons for our schedule and cost performance include several overlapping difficulties and challenges faced by the Program. The preliminary nature of our initial cost estimates failed to capture the true costs necessary to implement the overall Program. We made good faith estimates at the beginning of the Program based on historical experiences, but we were unable to anticipate future requirements due to an evolving regulatory environment. As a result of using high-level design estimates, we encountered substantial scope expansion and design changes, and this drove a portion of our Program costs. In addition to the design changes, we continued to underestimate the implementation difficulties that we faced. Yet, all of this additional work was necessary to complete the LCM/EPU Program, regardless of whether it was included in our preliminary estimate or accurately forecast.

The major cost drivers are: (i) Program design and scope changes; (ii) licensing delays; and (iii) the complexity of the modification installations. I will discuss each of these below, and I provide the variances between initial estimates and actual costs for each of the ten major Program modifications as an update to Information Request DOC-160 previously filed in our test year 2013 electric rate case at Exhibit ___ (TJO-1), Schedule 8.

1. Program Design and Scope Changes

Q. HOW DID THE COMPANY'S SELECTION OF PROGRAM MODIFICATIONS IMPACT THE COST OF THE PROGRAM?

A. 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 functionality and 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.

Q. WHAT WERE THE KEY PROGRAM SCOPE ADDITIONS THAT RESULTED IN COSTS IN EXCESS OF THE INITIAL ESTIMATE?

A. As I have mentioned, four major modifications account for $406 million – more than half of the total Program costs of $665. The Company made key decisions during the Program to substantially expand the scope of these four major modifications. These four key decisions were: (i) replacement of the feedwater heaters and associated equipment; (ii) replacement of the reactor feed pumps and motors; (iii) replacement of the entire condensate demineralizer system; and (iv) upgrade of the 4 kV electric distribution system to supplement the on-site power capabilities of the plant. I fully explain each of these decisions to expand the initial scope for these modifications, and why we incurred over $230 million to install these four modifications in Section VII of my Testimony.

In total, these four key scope changes account for nearly $86 million of incremental engineering and design, materials, and other non-installation costs compared to the initial project estimate of $320 million.

Q. DID SPECIFIC CONDITIONS AT MONTICELLO DRIVE ANY PROGRAM DESIGN DECISIONS?

A. Yes. Monticello was constructed in the 1960s, and the original design impacted the design choices available to us as part of this Program.

Monticello was constructed on a very small footprint. This limited our range of options for the design of certain replacement equipment and made aspects of the installation more challenging.

Furthermore, Monticello was not originally designed with license renewal in mind. Rather, it was constructed on the assumption it would operate for 40 years and its design was not conducive to replacing significant components to the operating plant. For example, the condensate demineralizer vessels are located in a vault with concrete walls. The walls were poured after the original vessels had been installed. In our efforts to replace the system we had to perform substantial work in a radioactive and extremely confined space.

The internal 4 kV electric distribution system was also sized for the plant as it was designed in the 1960s. That electric system served the plant well. Over the years, however, additional electric loads eroded much of the built-in margin, and the system was in need of additional capacity. The design decision to install the 13.8 kV system was not a decision to increase the voltage of the system but rather the decision to add additional bus work to accommodate new electric load associated with the uprate and to support additional loads for the next 20 years. The cost of this modification resulted from limited space in the turbine building to add additional busses, ultimately resulting in the need to install over 14 miles of cable.

2. Delays in the Licensing Process

Q. PLEASE DESCRIBE THE IMPACT ON THE PROGRAM FROM DELAYS IN THE NRC LICENSING PROCESS.

A. First, the LCM/EPU Program was confronted with unprecedented regulatory delays before the NRC. Those delays included an 18-month suspension of all review activities related to a specific portion of our License Amendment Request ("LAR"). That suspension was beyond our control and related to the NRC's desire to develop a consensus position on containment accident pressure ("CAP") requirements. The NRC's review also became more stringent after the events at the Fukushima Dai-ichi Nuclear Power Plant in March 2011.

In response, we expended substantially more dollars than we anticipated and more time than any prior applicant to meet the increasingly rigorous NRC standards and to provide new information in response to the NRC concerns.

Q. HOW DID THE NRC LICENSING DELAYS IMPACT THE PROJECT COSTS?

A. The regulatory delays impacted the Project costs in several ways. First, as we will explain, the licensing process was long and rigorous, and we performed more complex and costly calculations than we anticipated to facilitate the NRC's review of our licensing application. As a result, our licensing costs increased from an initial estimate of $28.6 million to approximately $60 million. We estimate an additional $5 million is required to complete the licensing effort through power ascension once the license amendments are granted. Second, the delay caused us to undertake a "gap" analysis, to confirm that the passage of time had not created additional issues. We were able to confirm that no new issues had arisen. Third, and most importantly, the extended and unexpected licensing effort delayed our ability to operate at uprate levels for the full duration of the extended license.

3. Installation Complexity

Q. HOW DID THE COMPLEXITY OF INSTALLATION CONTRIBUTE TO COSTS IN EXCESS OF THE ORIGINAL PROJECT ESTIMATE?

A. We incurred installation costs far in excess of our initial installation estimate. Our installation costs were nearly $290 million which is more than 40 percent of the total spend. Our initial estimate of $320 million included only $27.5 million for installation of the General Electric portion of the work. Our actual installation costs explain the sizable majority of the costs in excess of our initial $320 million estimate. These costs are summarized in Table 6.

Table 6. Initial Estimate Compared to Actual Cost.

Cost Category	2008 Certificate of Need Estimate	Actual Costs (August 31, 2013)	Variance 2013 – 2008
Installation Costs	$27.5*	$288.6	$261.1
All Other Costs	$292.5	$376.3	$83.8
Total	$320.0	$664.9	$344.9

*Partial Scope

We had initial estimates of installation from the original GE Scoping study. We also had some implementation costs built into our portion of LCM related costs. The difference between our original installation estimate and our actual installation costs can be attributed to the fact that we substantially underestimated the complexity and difficulty of completing the installation work. Nevertheless, these installation costs were required in order to complete the LCM/EPU Program, and the fact that our original estimate was substantially below our actual costs does not change the fact that this work was required to complete the Program.

a. Concurrent or Accelerated Projects

Q. HOW DID THE DECISION TO ACCELERATE CERTAIN MODIFICATIONS IMPACT THE IMPLEMENTATION COSTS?

A. We advanced numerous future maintenance activities and component replacements along with the LCM/EPU Program to maximize the implementation outages. I note that the majority of the components we replaced needed to be replaced during the license renewal period. It made sense to bundle those installations with the Program and take advantage of the economies of addressing multiple issues at the same time. While this resulted in a large amount of work during the LCM/EPU Program, it was a cost effective means of completing the work and prevented the potential for performing multiple replacements for competing purposes.

Q. DID THE COMPANY ACCELERATE CERTAIN PROGRAM MODIFICATIONS TO MAXIMIZE THESE LONG-TERM SAVINGS?

A. Yes. We chose to implement certain components replacements that would have been required at some point during the Monticello's extended life as part of the LCM/EPU Program, including the following Program modifications:

- Feedwater Heaters 13 A/B
- Dumps and Drains Piping
- Condensate Demineralizer Piping
- Condensate Pumps and Motors

- Reactor Feed Pumps and Motors
- Reactor Feed Pump Piping

Only one of these projects, the condensate pumps and motors project, was not included in the four key scope decisions I discussed above. As we progressed through the design and planning for the four key modifications, we elected to accelerate the piping, drains and other supporting components for these modifications. Many of these modifications were implemented jointly with other modifications in areas of the plant that are usually inaccessible.

Overall, the vast majority of the incremental installation costs were attributable to the four major modifications that constituted the Program's most substantial scope additions. As provided in Table 7, we incurred approximately $234 million to complete these modifications.

Table 7. Installation Costs of Four Key Scope Additions

MODIFICATION	INSTALLATION COSTS (MILLION $)
13.8 kV System Addition	73.4
Condensate Demineralizer System Replacement	36.1
Feedwater Heater Replacement	70.5
Reactor Feed Pump Replacement	53.8
Total	233.8

We estimate the acceleration of the dumps and drains piping to the scope of the feedwater heater modification added approximately $30 million to the cost of that modification. The condensate pump and motor modification totaled $21.9 million. The remaining components we accelerated contributed to the overall costs of the condensate demineralizer replacement and the reactor feed pumps and motors modifications. By replacing these components as part of the LCM/EPU Program we attempted to efficiently manage our resources and maximize the benefits of our Program investments.

Q. WAS THE AMOUNT OF WORK YOU ENCOUNTERED RELATED TO THE COMPANY'S PRIOR EFFORTS TO MAXIMIZE THE USE OF THE EQUIPMENT AT THE PLANT?

A. Ironically, it is. We were unusually successful at Monticello in keeping the original equipment usable for as long as possible. Four of our six feedwater heaters were original 40-year-old equipment, and the other two intermediate pressure 13 A/B heaters were 30-years-old. Our main transformer was original equipment that we successfully maintained for 40 years. The condensate demineralizer was also original equipment. We had maintained these systems to the maximum extent possible under the original life while many other units had replaced these portions of the plant earlier in their life.

The net effect of our strong efforts to maintain the original equipment at Monticello is that much of that equipment was worn and needed replacement. In order to keep Monticello available for its extended period of operations it became clear that we needed to replace many of these systems. While some of those systems could have lasted a few more years, many of them needed to be replaced right away. In all cases, we determined to combine the installations to maximize the long-term benefits to the plant.

b. Discovery of Design and Implementation Challenges

Q. PLEASE DESCRIBE THE CHALLENGES YOU FACED WITH EMERGENT WORK DUE TO SPECIFIC PLANT CONDITIONS.

A. We faced a variety of issues that arose because of the as-found conditions we discovered once the planned work had progressed into the construction phase. These issues took a variety of forms and required design and implementation adaptations to be undertaken on tight timelines to adhere to the outage schedules. For example, in the case of the condensate demineralizer replacement, the discovery of a backwash receiving tank design issue required expedited design changes in the months before the 2011 outage. As we were preparing to install new digital controls for the condensate demineralizer system, we found that the existing wiring had degraded and required replacement. As a result, we had to design and replace this wiring before proceeding with the control panel replacement. Similarly, we discovered during the 2009 outage that the as-built designs for the feedwater heater piping were incorrect. As a result, we had to prepare in-outage design and constructability packages to alleviate and avoid the piping interferences.

Though we expended great effort to fully analyze and plan for the work required to complete all of the modifications we were unable to walkdown all work areas due to the high radiological conditions in some areas of the plant. As a result we had to modify our construction and design plans on an expedited basis to maintain the outage schedule. Though we did not directly track the costs attributable to these discovery challenges, we incurred installation costs in excess of our initial implementation estimate as a result of this emergent work.

c. Productivity Challenges

Q. HOW DID PRODUCTIVITY ISSUES IMPACT THE PROJECT COSTS?

A. We overestimated the productivity for all of the three Project outages, and generally the implementation tasks required more labor hours than we originally expected. The Company found that construction labor productivity (i.e., the number of person-hours required to complete defined installation tasks) during the implementation outages was substantially lower than predicted by the Company's installation vendors. The Company attributes this productivity challenge to several factors, including the challenging work conditions, difficulties hiring experienced craft labor due to the competitive nuclear labor market, and restrictions on work schedules imposed by the NRC's fatigue rule.

d. Vendor Performance Challenges

Q. DID YOU AT TIMES NEED TO RETAIN MULTIPLE CONTRACTORS TO PERFORM DESIGN, ENGINEERING AND PROCUREMENT ACTIVITIES?

A. Yes, we did. We initially anticipated that the bulk of the design and engineering work would be conducted by General Electric. Although we were satisfied with some aspects of General Electric's support, we encountered difficulties with some of the design and engineering services.

As the Program moved forward, however, there were a number of modifications for which General Electric was not the optimal vendor. We required vendor support to proceed with the work on multiple parallel paths, which often resulted in tight schedules. Other times we used vendors to help us overcome specific design impediments. Finally, we needed to deploy replacement vendors when the initial design work was not satisfactory. We used additional vendors to integrate designs with our existing plant layout or complete alternative designs that we evaluated to be more cost-effective or easier to install or maintain. The vendors that supported our major modifications are listed in Exhibit ___ (TJO-1), Schedule 6.

Q. WAS THE COMPANY'S DECISION TO UTILIZE OTHER DESIGN PROFESSIONALS REASONABLE?

A. Yes. In order to complete the work promptly, it was necessary to bring others into the effort. This approach allowed us to capture maximum value from all of our vendors while also keeping the implementation on-track.

Q. DID XCEL ENERGY HAVE ANY DIFFICULTIES WITH ITS CONTRACTORS DURING THE PROGRAM?

A. Yes, there were multiple difficulties over the past six years, but nothing unusual for a project as large as this one. A number of the concerns were settled in the ordinary course of business. We are still working toward resolving a number of our other concerns.

Q. WHAT DO YOU RECOMMEND FOR THE TREATMENT OF CLAIMS IN THIS PROCEEDING?

A. The Company is pursuing these claims in good faith on behalf of our customers. Any recovery arising from claims should accrue to the benefit of our customers. We cannot guarantee, however, that claims will be successful or result in recovery of as much as we hope. We will work with parties to assure that customers receive the value of all recoveries we are able to achieve.

D. Conclusion

Q. WERE ALL THE COSTS INCURRED REASONABLE AND NECESSARY TO COMPLETE THE LCM/EPU PROGRAM?

A. Yes. Despite these cost and schedule drivers, the work we completed with the LCM/EPU Program delivered substantial benefits to the plant. Each new modification or component replacement was subject to hundreds of hours of study to:

- Maintain the safety of the plant,
- Ensure the right components were replaced to support the long-term operations and the EPU output,
- Optimize the selection and design of the new components, and
- Optimize the timing, sequencing and duration of the activities to minimize the length of the implementation outages.

Each of those new components is installed in the plant and was designed to enhance the safety of Monticello by increasing the margin between the design limit of the component and the current operating limits. In addition to being safer, we expect to experience fewer plant interruptions due to the increased margin. Our efforts also created a plant with new balance of plant systems that are well positioned to serve Monticello through 2030 and potentially beyond. From an engineering perspective, I see no reason why the balance of plant equipment that we installed could not operate beyond 2030.

V. EARLY PROJECT CHRONOLOGY

A. Program Initiation and Life Extension, 2003-2006

Q. HOW DID THE LCM/EPU PROGRAM BEGIN?

A. We started studying the LCM/EPU Program in the early 2000s when we began preparing for Monticello's license renewal. Our initial 40-year NRC operating license was set to expire in September 2010. The life extension licensing process can be lengthy and complex, and it requires full consideration of the LCM activities that may be necessary to support operation through the license renewal period.

We began preparing for this extensive effort in 2003. Before that time, Minnesota law effectively precluded us from renewing our license. As a result, the future of our nuclear fleet was uncertain, and to a large extent, we deferred nuclear capital investments in the 1990s and early 2000s given that the license for Monticello was set to expire in 2010. In 2007, Monticello's net plant rate base balance had depreciated to $153 million, reflecting the maintenance approach to capital investments we made during the preceding decade. These investments kept the plant safe, and operating reliably but no significant capital additions were made absent a pending license renewal. The Minnesota law precluding license renewal was amended in 2003, making it possible to seek a license renewal for Monticello.

Q. PLEASE DESCRIBE THE COMPANY'S EFFORTS TO PURSUE NRC APPROVAL OF MONTICELLO'S 20-YEAR LICENSE RENEWAL.

A. We believed maintaining operations at our nuclear plants for another 20 years provided more ratepayer value compared to the available alternatives. As described in more detail by Mr. Alders, once we obtained legal authority to proceed, we sought two approvals necessary to keep Monticello operational through 2030: (i) a Minnesota certificate of need for authority for on-site fuel storage, and (ii) a renewed operating license from the NRC. We obtained both of these approvals in 2006.

Q. DID THE COMPANY CONSIDER UPRATING MONTICELLO'S CAPACITY DURING ITS LICENSE RENEWAL PLANNING?

A. Yes. We recognized that capital investments were needed to ensure the long-term safe and reliable operation of the plant to support the license extension. We categorized these investments as life-cycle management. These investments were necessitated by aging equipment concerns, new or evolving regulatory requirements, operating experience at other nuclear plants, obsolescence and new technologies. Some of these replacements were required in the short term, while others were identified for completion later in the license renewal period.

When we assessed the component modifications and replacements necessary to support life extension, we noted that many of the same components prevented the plant from reaching a higher electrical output. As Mr. Alders explains, we were also aware at this time that Xcel Energy was in a period of sustained high demand growth, and in 2004 we forecasted an increased need in excess of 1,000 MW for new baseload capacity by 2015. We elected to pursue an uprate to Monticello as a means to meet a portion of this forecasted demand.

B. EPU Initiation and Contracting, 2006-2007

1. Initial Studies and Approvals

Q. HOW DID XCEL ENERGY IDENTIFY THE POSSIBILITY OF COMPLETING AN EPU PROJECT?

A. In 2004, Xcel Energy asked General Electric to complete an initial feasibility study for an uprate at Monticello. In 2006, Xcel Energy requested that General Electric provide additional study of the possibility of completing an EPU. This request culminated in an initial cost scoping assessment that was provided to Xcel Energy in May 2006. This study identified the component modifications and replacements necessary to achieve uprate conditions. While this study incorporated analysis of the cost to complete the EPU, detailed engineering was not completed, and the scoping study incorporated only limited feedback from Monticello personnel. The assessment was presented as a high-level estimate subject to additional review and development as the project proceeded.

Q. WHAT ACTIVITIES DID XCEL ENERGY UNDERTAKE TO FURTHER ANALYZE THE POSSIBILITY OF COMPLETING AN EPU AT MONTICELLO?

A. As described previously, the EPU portion of the project was part of the larger objective to extend the life of the Monticello facility. As a result, it was necessary for the Company to identify the cost of other modifications that were required to support the continued operation of Monticello for at least 20 more years. We undertook this effort by reviewing our long-range capital investment plans for the Monticello plant.

Between May 2006 and August 2006, we studied the General Electric cost scoping assessment and our LCM initiative to develop a high-level conceptual estimate of the cost to complete the combined LCM/EPU Program. In August 2006, we determined it was in the best interests of our customers to pursue the LCM/EPU Program.

The original nuclear project authorization ("NPA") for this work was for $273 million (2006$), with implementation outages scheduled in 2009 and 2011 to coincide with our regularly-scheduled refueling outages. The estimate included a large category of costs related to General Electric's scope of work to complete certain LCM/EPU modifications and prepare the NRC license amendment request. The estimate also included costs related to Xcel Energy's scope of work to complete certain Project modifications and to provide project management and support.

Q. DID XCEL ENERGY ULTIMATELY ENTER INTO A CONTRACT WITH GENERAL ELECTRIC FOR THE SCOPE OF WORK DISCUSSED ABOVE?

A. Yes. We executed two agreements with General Electric in the Fall of 2006. A phase one agreement was executed with General Electric on September 26, 2006, and a phase two agreement was executed on December 20, 2006 (collectively the "General Electric Agreements").

Q. PLEASE PROVIDE AN OVERVIEW OF BOTH GENERAL ELECTRIC AGREEMENTS.

A. The phase one agreement provided a non-transferable license to use General Electric's proprietary licensing topical reports to support our preparation of the NRC license amendment request. The phase two agreement provided for General Electric to prepare the license amendment request, and to engineer, design and procure the necessary components and modifications to implement the LCM/EPU Program in two successive refueling outages in

2009 and 2011. It did not include installation of the various components in, and modifications to, the plant. These services were to be provided by a third party. In addition, the phase two agreement excluded portions of the LCM/EPU Program that were to be completed by Xcel Energy.

Q. PLEASE DESCRIBE THE DIVISION OF RESPONSIBILITY BETWEEN XCEL ENERGY AND GENERAL ELECTRIC.

A. General Electric was responsible for completing its defined scope of work in a quality manner to support the implementation of the EPU immediately following the Spring 2011 outage. Monticello is an NRC-licensed facility, and as the licensee, Xcel Energy is responsible for the health and safety of the public proximate to the facility. Thus it was necessary for Xcel Energy to oversee work performed by General Electric and its subcontractors to make certain they were qualified for use in the plant. As the project developed and grew, we also staffed an internal engineering project organization to allow for proper oversight.

Q. WHY DID THE COMPANY DECIDE TO CONTRACT WITH GENERAL ELECTRIC FOR THE ENGINEERING AND PROCUREMENT NEEDED TO COMPLETE THE LCM/EPU PROGRAM?

A. The fact that General Electric was the original designer of Monticello and its ample financial and operational record were the primary reasons for our choice. A profile of General Electric is provided in Exhibit ___ (TJO-1), Schedule 10. Many other utilities also retained the original station designer to assist in uprate and refurbishment projects. See Exhibit ___ (TJO-1), Schedule 11. General Electric holds proprietary rights to aspects of the design basis at Monticello, and it was most efficient to use their prior knowledge and experience for this work.

Further, General Electric previously prepared and received approval for a series of license topical reports that are a roadmap for generally completing the technical analyses necessary to complete a license amendment request for an EPU. As the NRC Staff stated to the commissioners in 2001:

> In addition to plant-specific power uprate applications, General Electric Nuclear Energy ("GENE") has submitted four topical reports (one in 1990, one in 1991, one in 1995, and one in 1996) in which it proposed guidelines to be followed by BWR licensees in the preparation and submittal of power uprate applications. These topical reports covered stretch and extended power uprates up to a 20-percent increase power level. <u>The staff has reviewed and approved these topical reports. The use of topical reports has many benefits.</u> Specifically, it provides a template that standardizes licenses applications for power uprate submittals, improves the quality of licensees' submittals, and provides focus for staff technical review. This also leads to fewer requests for information during the staff's reviews of plant-specific applications and a more efficient review by the staff.

Those reports were previously reviewed and approved by the NRC, and it is more cost-effective to rely on these reports, by obtaining the necessary license, rather than recreate this information with a third party.

Finally, the agreement with General Electric permitted the use of subcontractors to supplement its expertise and gain access to specialists in the design and manufacture of certain components. General Electric's primary subcontractor during the course of the Monticello LCM/EPU Program was the Shaw Group ("Shaw"). Shaw served as General Electric's primary engineering subcontractor to support engineering and design of the LCM/EPU modifications. A detailed profile of Shaw is provided in Exhibit ___ (TJO-1), Schedule 12.

Q. WHAT WAS THE ORIGINAL IMPLEMENTATION SCHEDULE CONTEMPLATED BY THE 2006 GENERAL ELECTRIC COST SCOPING STUDY?

A. The General Electric Scoping Study provided two potential schedule scenarios for completing the Monticello LCM/EPU project. In the first scenario, the Program would be completed in two sequential refueling outages in 2009 and 2011. In the second scenario, the Program was to be completed in sequential refueling outages in 2011 and 2013. We elected to pursue the former schedule to meet the impending capacity need identified in our 2004 and 2007 Resource Plan proceedings.

2. Day Zimmerman Implementation Contract

Q. DID THE GENERAL ELECTRIC AGREEMENTS PROVIDE FOR THE CONSTRUCTION AND IMPLEMENTATION OF THE MODIFICATIONS?

A. No. General Electric included an installation proposal in the 2006 contract, but it was not a firm price, and there was no binding commitment for General Electric to perform the installation work.

Q. HOW DID THE COMPANY CHOOSE AN INSTALLATION CONTRACTOR TO IMPLEMENT THE PROGRAM?

A. In mid-2007, we issued a Request for Proposals to Bechtel Corporation, Areva NP, General Electric/Shaw, Sargent & Lundy, and Day Zimmerman to gauge their interest in performing the implementation scope of work.

We received two responses to the Request for Proposals; one each from the consortiums of General Electric and Shaw and of Day Zimmerman and Sargent & Lundy. Neither bidder was willing to entertain the earlier General Electric installation estimate, rather they made proposals based on their own updated analysis. Both proposals involved time-and-materials-type pricing structures. Two other candidates elected not to provide a proposal. We performed a quantitative and qualitative assessment of both proposals and selected the joint bid of Day Zimmerman and Sargent & Lundy. We subsequently issued a release to Day Zimmerman in December 2007, for work planning and installation services.

Q. WHO IS DAY ZIMMERMAN?

A. Day Zimmerman is a large privately held company based in Philadelphia, PA. The company, through multiple divisions, provides work planning, installation, welding and staff augmentation services to the nuclear power industry. Day Zimmerman is widely used in the nuclear power industry to perform these services. A detailed profile of Day Zimmerman is provided in Exhibit ___ (TJO-1), Schedule 13.

Q. WHY DID THE COMPANY DECIDE TO COMBINE THE LCM AND EPU INITIATIVES INTO ONE PROJECT?

A. Our decision was based on multiple factors. First, there was extensive overlap in the work that needed to be completed concurrently at the plant. By completing these efforts simultaneously, the Company could expect savings in expenses and could achieve economies by doing more work simultaneously. Second, the combination of these projects reduced the expected aggregate duration of outages. While the results of this combination may include replacing some components somewhat ahead of schedule, in the long-term this was a more efficient way to proceed overall.

C. NRC Licensing Process

1. Overview

Q. PLEASE DESCRIBE THE NRC'S LICENSING PROCESS.

A. The NRC licensing process consists of a highly detailed and technical review of the proposed construction and operating characteristics of the facility. The facility must be analyzed and must demonstrate that it is capable of operating safely and it is capable of responding adequately in the event of postulated accident scenarios. Once the NRC issues an operating license it undertakes periodic inspection activities to verify the licensee's compliance with the operating conditions. Two NRC inspectors are stationed on-site at each nuclear facility to ensure compliance with the license requirements. Overall, the process of obtaining and maintaining an NRC operating license requires extensive effort.

Q. DOES THE NRC NEED TO APPROVE THE EPU PROJECT?

A. Yes. To operate at uprate conditions the Company requires NRC approval of changes to the operating conditions and limitations within our license.

Q. PLEASE DESCRIBE THE LICENSE APPLICATIONS THAT XCEL ENERGY HAS MADE IN CONNECTION WITH MONTICELLO.

A. We submitted the current EPU license amendment request to the NRC in late November 2008. In that application, the Company demonstrated that the plant will safely operate at uprate conditions (2004 MWt or 671 MW). Once approved, the EPU license amendment will allow Monticello to increase the thermal output of the reactor and increase the electrical output of Monticello. All preliminary analysis and subsidiary approvals have been received, including approval by the ACRS. As a result there is no action remaining except for review and approval by the full NRC Commission and we expect to receive final uprate approval by the end of 2013.

In addition, the Company is pursuing a second license amendment related to Monticello's nuclear fuel configuration, that will allow the plant to operate more efficiently pursuant to General Electric's Maximum Extended Load Line Limit Analysis Plus ("MELLLA+") licensing topical report. We submitted the MELLLA+ request to the NRC in January 2010. We are seeking MELLLA+ approval to provide operational stability and flexibility at the uprate thermal power level. MELLLA+ is an engineering analysis that provides for greater operational flexibility and ease to safely operate units at maximum power for longer periods. While the plant could operate at the uprate thermal power level without MELLLA+ approval being in place, such operations would be more susceptible to forced outages. We anticipate operating at 635-640 MW, until we receive MELLLA+ approval in early 2014. The MELLLA+ license amendment, has always been scheduled for issuance shortly after the receipt of the EPU license amendment.

2. *EPU Licensing Process*

Q. WHEN DID THE COMPANY FIRST FILE ITS EPU LICENSE AMENDMENT REQUEST?

A. We filed the original EPU license amendment request with the NRC on March 31, 2008. A summary of our licensing activities and incurred costs is provided at Exhibit ___ (TJO-1), Schedule 17.

Q. DID THE NRC ACCEPT THE INITIAL EPU LICENSE AMENDMENT REQUEST?

A. No. NRC staff had concerns about whether we satisfied the NRC's "completeness" review. We withdrew the request in response to a June 26, 2008, NRC letter raising those concerns. We resubmitted the EPU License amendment request on November 5, 2008. In the amended application we changed the configuration to include a new steam dryer component (as opposed to modifications to the existing steam dryer). On December 18, 2008, NRC staff concluded the application met the completeness requirements to enable the NRC staff to proceed with detailed review of the application.

Q. HOW LONG DOES THE NRC USUALLY TAKE TO COMPLETE ITS REVIEW OF AN EPU LICENSE AMENDMENT REQUEST?

A. At the time we submitted the EPU license amendment request, the NRC targeted a review period of approximately 12 months. Since that time, the NRC has amended its review period to approximately 18 months. Nevertheless, the NRC is permitted to take more time to assure safety of the plant and its systems.

As shown in Table 8, before 2007 the NRC completed its review of 15 EPU amendment request applications from other operators of BWR facilities in an average time of 1.2 years per application. For applications filed in 2007 and after, however, the average duration increased by a full year to 2.2 years. This is more than twice the NRC's 12-month target, and still four months longer than the 18-month target.

Table 8. NRC Average Review Duration of Approved Uprate Applications

	Boiling Water Reactor (like Monticello)		Pressurized Water Reactor (like Prairie Island)	
	Pre-2007	**Post-2007**	**Pre-2007**	**Post-2007**
Number of EPU Applications	15	2	5	6
Average Review Time (Yrs.)	1.2	2.2	1.5	1.8

Q. HOW LONG HAS THE MONTICELLO EPU LICENSE AMENDMENT REQUEST BEEN PENDING?

A. Nearly five years from acceptance of the amended application.

Q. PLEASE FURTHER DESCRIBE THE NRC'S REVIEW PROCESS FOLLOWING THE ACCEPTANCE OF THE EPU LICENSE AMENDMENT REQUEST?

A. Following completeness review, the NRC initiates a comprehensive safety and environmental review request. During that review the NRC will identify additional information that it needs to complete the reviews.

Q. HOW MANY REQUESTS FOR ADDITIONAL INFORMATION WERE RECEIVED BY XCEL ENERGY?

A. We have received 420 information requests (plus multiple subparts) for the EPU License amendment request and 46 information requests for the MELLLA+ request. This is significantly more than we anticipated.

Q. WERE YOU ABLE TO PREDICT ALL OF THE NRC'S CONCERNS AND QUESTIONS BASED ON YOUR REVIEW AND BENCHMARKING OF PREVIOUS EPU APPROVALS?

A. No. We encountered significant challenges in two main areas that were unexpected: (i) a credit in safety analysis for "containment accident pressure" ("CAP"), and (ii) ongoing structural analyses of the new steam dryer. Both of these issues are discussed below, and each was a significant contributor to the cost of the licensing effort.

Q. WHOSE RESPONSIBILITY WAS IT TO PREPARE THE LICENSE AMENDMENT REQUESTS?

A. Responsibility for completing license amendment requests was split between Xcel Energy and General Electric. Both the Company and General Electric were impacted by the heightened scrutiny as General Electric had a fixed price for the NRC information request part of the effort and has assisted on the hundreds of NRC staff requests on that basis despite there being many more than anticipated. Our licensing costs would have been even higher had we had to pay the incremental costs of all of the additional NRC inquiries.

3. Licensing Challenges

a. CAP Analysis

Q. WHAT IS CAP?

A. In boiling water reactors like Monticello, the EPU increases the temperature of the water in containment, and this higher temperature could affect the ability of the emergency core cooling system to cool the reactor core and containment. CAP credit refers to the reliance in safety analyses on the use of a portion of the increased pressure in the primary containment structure to demonstrate acceptable performance. In prior EPUs the NRC accepted the CAP analysis.

Q. WHY DID THE CAP REQUIREMENTS CHANGE?

A. A disagreement arose between the NRC staff and the NRC's independent advisory committee, the ACRS. Generally, the NRC staff thought the CAP analysis was satisfactory, and the ACRS thought additional analysis was required to demonstrate the use of CAP. Ultimately, in October 2009, the NRC officially informed the Company that the agency required more time to develop additional regulatory guidance on the issue. The NRC did not resolve the internal disagreement until April 2011, just after the events at Fukushima.

Q. SHOULD THE COMPANY HAVE FORESEEN THE INTRA-AGENCY DISPUTE ON CAP?

A. No. Other boiling water reactors, such as Duane Arnold and Vermont Yankee obtained uprate licenses that included CAP credit. The issue of CAP credit was deemed a policy issue, meaning it was one that rose to the level of general applicability to assess the preference of the agency. In fact, deterministic modeling of CAP credit indicated its risks were in the very remote range and safety significance not to the level of triggers. Company executives met with all five NRC Commissioners in late 2010 and early 2011 seeking a vote on this issue. That vote eventually took place in Spring 2011, as the events surrounding Fukushima were unfolding.

Q. HOW DID THE EVENTS AT FUKUSHIMA AFFECT THE CAP ANALYSIS?

A. The NRC vote was a positive one, and the Company thought the CAP issue was successfully resolved just as the events of Fukishima unfolded. We understood that the NRC was going to publish its resolution of CAP requiring certain additional analytics. That guidance was published just after Fukushima. However, we were working on a procedure change that could occur in the interim while we moved through the analytics that would allow the NRC to issue the uprate license. We believed the NRC staff supported this approach. That support, however, changed quickly after Fukushima.

Specifically, the final NRC guidance gave the staff latitude to require significant additional analysis to confirm the outcome. In light of the importance of containment pressure control highlighted by the events at Fukushima, NRC reviewers spent the next two years analyzing the issues. As with the original CAP dispute, the need for this further analysis was not foreseeable.

b. Steam Dryer Analysis

Q. PLEASE DESCRIBE THE SECOND TECHNICAL ISSUE THAT LED TO AN INCREMENTAL LICENSING EFFORT THAT CONTRIBUTED TO THE LENGTH OF NRC REVIEW.

A. The other main issue that contributed to the depth and duration of the NRC review was the NRC's evolving expectations for structural analyses of steam dryers.

Q. DID THE COMPANY'S NOVEMBER 2008 DECISION TO REPLACE THE STEAM DRYER RESOLVE THE NRC CONCERNS?

A. Not entirely. The NRC accepted our November 2008 EPU license amendment request as complete for review, but the NRC remained concerned generally with steam dryer structural integrity. The NRC's review shifted to an analysis of whether the structural analysis of the new steam dryer was sufficient. This issue was the last substantive issue to get resolved with the ACRS in September 2013. The ACRS letter recommending that the NRC issue our EPU license amendment is included with my testimony as Exhibit ___ (TJO-1), Schedule 18. The review of the new steam dryer included numerous iterations of the analyses, and each iteration of the analysis required significant costs to complete.

Q. WHAT WERE THE COSTS INCURRED WITH REGARD TO THE COMPANY'S LICENSING EFFORT?

A. I will address the costs of licensing along with the costs of the major modifications in the next section of my testimony.

VI. IMPLEMENTATION

A. Program Start-Up

Q. WHY DID THE COMPANY DECIDE TO SCHEDULE THE MODIFICATIONS TO BE INSTALLED OVER TWO REFUELING OUTAGES IN 2009 AND 2011?

A. Our decision to implement the Program as quickly as possible was based on interrelated factors. First, as I have described, the Company's ability to make large upgrade investments in modernizing its nuclear facilities was largely placed on hold for over a decade beginning in the 1990s, and we were behind in our investment cycle. Once the law changed making is feasible for us to pursue a license renewal, the Company moved quickly to pursue license renewal approvals to facilitate the planning of key life-cycle investments.

Second, we determined an uprate was the most cost-effective alternative to meet the forecasted demand, and we needed to move promptly to meet that need. We sought to move quickly to capture the customer benefits of increased output over the license renewal period. It was in our customers' best interests to get the fuel savings from the upgrades for as long as possible and to spread the costs of significant construction over as long a period as possible.

We proceeded with our state and federal regulatory uprate filings simultaneously rather than sequentially because we did not want to lose the time needed to make key asset improvements while achieving an integrated design for the Project. The Company was able to start installation during the 2009 refueling outage despite the fact that we only received our certificate of need from the Commission in January 2009. We invested considerable effort to prepare for the 2009 outage, so that we could begin implementation just months after receiving the certificate of need. We procured equipment, undertook significant engineering and developed the plans for those installations to capture the benefits for our customer of upgrading Monticello for the long term. We also worked through many key design issues in the 2006-2009 timeframe.

Q. HOW DID THE FORECASTED DEMAND IMPACT THE LCM/EPU PROGRAM DEVELOPMENT?

A. The forecasted need meant that Xcel Energy had to proceed with its implementation plans on multiple tracks simultaneously. We began moving forward with the LCM/EPU Program in 2006, shortly after receiving the Commission's approval for license renewal, to assess the necessary modifications and improvements. Although we knew it would take longer to achieve NRC EPU approval, based on past experience and NRC policy at the time, we did not consider this to be a significant risk.

Q. DID THE NEED TO MULTI-TRACK THE PROGRAM CONTRIBUTE TO THE DIFFERENCE BETWEEN THE INITIAL ESTIMATES AND THE FINAL COST?

A. To some degree, yes. The compressed Program schedule required the Company and its vendors to use informed assumptions to begin the design, licensing and engineering activities. In some instances, these assumptions did not prove correct, and scope changes were necessary to accommodate the actual plant condition and Program requirements. Though we made several design changes that impacted scope, we did not fully appreciate the difficulties we ultimately faced in implementation. While more time may have led to somewhat better initial estimates, I believe that we would still have underestimated the cost of the Program. The best example of this is our 13.8 kV modification. In this modification, our estimate was initially about $20 million and soon moved to roughly $30 million, but the project cost $120 million after final design and implementation.

Q. DO YOU BELIEVE THAT IT WAS REASONABLE FOR XCEL ENERGY TO ADOPT THIS APPROACH FOR THE LCM/EPU PROGRAM?

A. Yes, I do. The decision to use this approach was based on a need to complete the Program promptly, approximately two years faster than would have been possible had we managed each phase of the project sequentially. Ultimately, development of a third outage was necessary to ensure all required work could get done. Our objective was to move as quickly as possible, but the amount of work necessary could not be accomplished in two outages.

1. *Implementation Team*

Q. WHAT STEPS DID THE COMPANY TAKE TO PREPARE FOR IMPLEMENTATION OF THE PROGRAM?

A. While we were assessing the feasibility of the Program, we began the necessary tasks of staffing a dedicated project management team. An organizational chart depicting the project organizational structure in 2007 can be found as part of Exhibit ___ (TJO-1), Schedule 14.

Q. WHO WAS RESPONSIBLE FOR THE PROGRAM ORGANIZATION DURING THE 2006 TO 2008 TIMEFRAME?

A. The Nuclear Management Company ("NMC") was our contract manager for our nuclear units at that time. NMC was responsible for implementing the LCM/EPU upgrades on our behalf. NMC dissolved in 2008 while the EPU certificate of need was pending, and the management functions were absorbed back into the Company.

Q. HOW DID XCEL ENERGY STAFF THE LCM/EPU PROGRAM MANAGEMENT TEAM?

A. Once we assumed NMC's management function, we continued the approach of using existing employees, retirees and contractors to fill project management roles. For the bulk of the labor needed to implement the LCM/EPU upgrades we hired union labor through our implementation contractor. One of the Project's challenges was that the pool of available qualified resources immediately available to assist with the project was limited, and we utilized all available internal resources to fulfill the Project staffing needs.

Q. HOW DID LABOR CONSTRAINTS IN THE NUCLEAR INDUSTRY IMPACT THE PROGRAM STAFFING?

A. As we discussed in our recent rate cases, the nuclear industry is in a state of increasingly constrained resources. With only 67 nuclear generating facilities in the United States, the domestic labor market is small and tightly knit, creating a highly competitive market for resources. Contributing factors leading to this competitiveness include an aging workforce and a general shortage of entry-level candidates.

At the same time the available labor market was decreasing, the demand for nuclear labor was increasing. When we were developing our project team, major nuclear projects in the United States and Canada were competing with the LCM/EPU Program for qualified personnel, including:

- the steam generator replacements at San Onofre, Crystal River 3 and Diablo Canyon;
- the EPUs at Crystal River 3, Point Beach, St. Lucie, Turkey Point, Grand Gulf and various Exelon nuclear units;
- the completion of Watts Bar Unit 2;
- the construction of Vogtle 3 and 4, and Summer 2 and 3;
- the Ft. Calhoun restart;
- the refurbishment and restart of four reactors at the Bruce Generating Station in Ontario;
- the refurbishment of four reactors at the Darlington Generating Station in Ontario; and
- the refurbishment of one reactor in New Brunswick.

This situation forced the Company to compete for a limited pool of skilled personnel.

2. *Project Management Plan*

Q. WHAT TOOLS DID THE COMPANY USE TO SET THE PROGRAM OBJECTIVES AND PARAMETERS?

A. The project management team prepared a project management plan that included a framework to manage certain aspects of the project including issues such as scope and quality control. This plan set forth a series of project principles that were the guidance for how the Company was to implement the Program. These principles focused on increasing safety and reliability, incorporating industry experience and extracting values from economies of scale.

Q. WERE THERE ASPECTS OF THE PROJECT MANAGEMENT THAT YOU WOULD HAVE DONE DIFFERENTLY?

A. I think so. While I believe our engineering group did a good job of identifying issues and designing solutions, I may have scheduled a more robust project management in advance of the increased scope. The need for additional project management was not clear to us in 2009 as we moved into and completed the outage and our work with General Electric and Day Zimmerman went relatively smoothly. As we moved through 2010, we began to face design challenges and a need for greater oversight of quality issues. We reacted well by quickly responding to concerns, developing design solutions, establishing recovery plans for the 2011 outage and eventually changing the management structure following the 2011 outage. While I believe the change was appropriate as the Program evolved, it did not reduce our costs. Instead, our 2013 outage, which had the benefit of substantial longer upfront planning and design still took longer than anticipated and cost more than we had forecast.

3. LCM/EPU Program Phases

Q. WHAT WERE THE PHASES OF THE PROGRAM?

A. The Monticello LCM/EPU Program was organized around three basic phases:

1) Initiation and Definition: activities necessary to better define the scope of the LCM/EPU Program, identify program vendors and identify long-lead components and materials. Generally, this phase of the Program occurred between 2006 and 2008.

2) Design and Engineering: detailed engineering, procurement specifications, drawings, calculations and implementation plans. Additional work involved procuring long-lead components; preparing detailed modification packages; issuing construction drawings; performing technical calculations; and identifying high-level testing requirements. This Program phase primarily occurred between 2007 and 2010. Some design and engineering activities, however, occurred as late as 2012 to support the completion of the 2013 outage.

3) Installation: activities, including detailed work packages and construction efforts that took place before and during each of the Monticello refueling outages in 2009, 2011 and 2013. The installation phase consisted of converting the design packages and drawings into detailed work packages and tasks for implementation. Revisions to the design are often warranted based on constructability.

Q. WHY DO THE PHASES OVERLAP?

A. As I discussed, we targeted completion of the Program in 2011. To meet that target, it was necessary to perform certain work in parallel.

Q. PLEASE DESCRIBE THE DESIGN AND ENGINEERING PROCESS EMPLOYED IN IMPLEMENTING THE LCM/EPU PROGRAM.

A. Overall, the design and engineering process was used to conduct a systematic review of each system and determine the need for replacement or modification. This process began with a review of our licensing requirements to identify 'pinch-points' that limited the ability of the plant to operate at uprated capacity levels. We then created solutions to address these pinch points and prepare the EPU license amendment through the engineering process.

The goal of such a multi-layered review process is to ensure that all design and engineering decisions have been thoroughly analyzed by design management to ensure the safety of the plant, our workers and the surrounding communities. Each stage becomes increasingly more rigorous and is designed to provide multiple opportunities for design and engineering issues to be properly identified and addressed.

Changes in design are a normal part of doing work at a nuclear plant. Engineering design development requires iteration for two reasons. First, initial engineering designs are not intended to meet performance criteria at a component or system level and must be adjusted prior to their implementation to account for requirements that may be identified through impact reviews from station and engineering programs. Second, new information frequently comes to light during the course of an engineering-intensive program that requires revisiting previous engineering design work.

Q. IS THE DESIGN AND ENGINEERING PHASE ESPECIALLY COMPLICATED FOR MAJOR MODIFICATION PROJECTS AT OPERATING NUCLEAR POWER PLANTS?

A. Yes. Two issues make it more complicated and costly to modify an older nuclear facility such as Monticello. First, certain plant systems experience degradation over time, resulting in diminished operating margins. Second, an EPU subjects a nuclear facility to NRC scrutiny that may necessitate changes to a plant's original licensing basis, which may involve additional engineering changes and equipment upgrades beyond those initially envisioned to meet the EPU operating requirements.

Q. WHAT METHODS DID THE COMPANY USE TO OVERSEE THE PROGRAM DESIGN AND IMPLEMENTATION?

A. Xcel Energy used a number of internal review committees that provided oversight of the design effort. These committees met regularly to approve scope changes, manage vendor performance and address design questions. We also worked with our external design organizations to oversee vendor services, such as communications, quality assurance and quality control, work processes, scope of work and task authorizations and design control. Our initial work planning and oversight functions were less robust in part due to our expectations that General Electric would deliver specific designs and equipment. This approach worked well for the 2009 outage, but delays in design and other issues in 2010 made this structure challenging during the 2011 outage. As we experienced issues with design and fabrication of equipment, our involvement in the work increased. We occasionally moved design work to other vendors, required additional review and analysis and added on-site inspections of equipment that had failed to meet specifications.

Q. WHO IS RESPONSIBLE FOR THE QUALITY OF WORK CONDUCTED AT THE NUCLEAR PLANTS?

A. Under 10 CFR Part 50, Appendix B, Xcel Energy as the licensee is required to maintain a qualifying Quality Assurance and Quality Control ("QA/QC") function. The Monticello LCM/EPU Program and our vendors were subject to numerous QA/QC site inspections, audits and oversight throughout the course of the project. Our QA/QC function reviewed our work products, design activities and the goods and services that we procured from our vendors. We rejected several key components in this process, and I believe this is an area where our efforts are proving the benefits of this approach. We are not experiencing in-service equipment issues as has occurred at other facilities.

Q. WHAT WAS THE FINAL LIST OF MODIFICATIONS INCLUDED FOR INSTALLATION AS PART OF THE LCM/EPU PROGRAM?

A. A table of modifications, including the refueling outage in which we originally expected to install the modification, the refueling outage in which we completed the modification, our total spending on each modification and the reasons for changing the completion dates is provided at Exhibit ___ (TJO-1), Schedule 15.

B. Overview of Installation Process

Q. WHEN WERE THE LCM/EPU PROGRAM MODIFICATIONS INSTALLED AT THE PLANT?

A. The installations were completed during Monticello's regularly scheduled refueling outages in the spring of 2009, 2011 and 2013. Table 9 provides the duration and aggregate cost of the three LCM/EPU Program implementation outages.

Table 9. Outage Durations and Cost

Outage	Duration		Costs Incurred	
	Planned	Actual	Planned	Actual
2009 Outage (RFO 24)	45 days	56 days	$25 million	$34 million
2011 Outage (RFO 25)	65 days	81 days	$101 million	$133 million
2013 Outage (RFO 26)	85 days	138 days	$99 million	$151 million

Q. ARE THESE OUTAGE COSTS THE SAME AS THE INSTALLATION COSTS REPORTED ON THE COMPANY'S FUNCTIONAL COST CATEGORIZATION ANALYSIS?

A. No. The outage costs shown above are a portion of the installation costs in Table 2. As I discussed above and as further explained by Mr. Weatherby, Xcel Energy analyzed its LCM/EPU Program spending to assign costs to several functional cost categories, including installation. The actual outage costs shown in Table 9 do not necessarily encompass all of the costs categorized as installation for the purposes of the cost categorization exercise, in part due to the timing of the accounting transactions. Implementation costs include the development of detailed work planning packages that are developed before the outages while the outage costs focus on mobilization and completion of the installations.

Q. WHAT TYPE OF ACTIVITIES TAKE PLACE DURING A NUCLEAR REFUELING OUTAGE?

A. The main purpose of a refueling outage is to replace depleted fuel with new fuel. During a refueling outage, plant workers have greater access to high radiation areas that are difficult to access during normal operations, such as areas close to the reactor core. To the extent possible, we try to coordinate maintenance and capital projects with refueling outages.

Q. WHAT ARE THE KEY OUTAGE PLANNING MILESTONES?

A. In accordance with industry standards, we use nine planning milestones with specific timing requirements to ensure planning will meet the outage schedule. Key outage planning milestones include scope identification, work package planning, procurement, work order walkdowns and schedule preparation and refinement, all scheduled to be completed a number of months before the outage.

Q. DID THE COMPANY FOLLOW THESE OUTAGE PLANNING MILESTONES FOR THE LCM/EPU PROGRAM?

A. We did not impose the milestone dates for our 2009 outage planning because we were proceeding on an expedited basis. For the 2011 and 2013 outage preparations, we restored the expectations that the milestones would be met.

Q. DID THE COMPANY TAKE STEPS TO ADDRESS MILESTONES THAT WERE AT RISK DURING THE PREPARATION FOR THE LCM/EPU PROGRAM OUTAGES?

A. Yes. When our project management recognized that planning milestones were at risk of not being met, the Company developed recovery plans. To develop these plans, we identified the reason for slippage, the effect on successor cascading milestones, plans to communicate the risk of slippage for successive work in other departments that may be impacted and courses of action to recover and meet the milestone.

1. Staffing of Implementation Outages

Q. HOW ARE OUTAGES STAFFED?

A. Typically, existing plant staff is augmented by outside contractors and contract labor to complete the numerous tasks in the specified time frame. In general, the contract labor is highly trained and goes from plant site to plant site to assist in refueling outages. They are also trained on site-specific requirements and must adhere to all of the same processes and procedures as the plant's full-time workers. While onsite, each contractor is closely monitored to ensure that they are safe and adhere to all NRC regulations.

During a typical refueling outage, approximately 2,000 supplemental workers are added to the plant's existing staff and the combined workforce performs work on a demanding 24/7 schedule to complete thousands of upgrades and safety inspections as well as refueling activities We performed more than 39,000 separate tasks, including capital and refueling tasks, during the three Program implementation outages in 2009, 2011 and 2013.

2. Execution of Outages

Q. WHAT TOOLS ARE USED TO MONITOR IMPLEMENTATION OUTAGE PROGRESS?

A. We use several tools, including a computerized database and detailed scheduling software to monitor implementation progress. We track the actual schedule against the original schedule for doses, number of OSHA reportable events, number of tasks not executed and number of unplanned tasks.

Q. IS IT COMMON FOR MAJOR TASKS TO TAKE A CRITICAL PATH FOR IMPLEMENTATION DURING A PLANNED OUTAGE?

A. Yes. The critical path is the longest path through the sequence of activities conducted during an outage. This may include major project activities that need to be completed to return systems to service and to restore the plant to operations. It is very common for major tasks involving complicated removal and installation activities to become critical path items.

3. Post-Installation Testing

Q. AFTER INSTALLATION OF A MODIFICATION, ARE THERE TESTING REQUIREMENTS TO ENSURE THE WORK WAS COMPLETED CORRECTLY?

A. Yes. Before a modification is completed and turned over to the plant's operational personnel, there are rigorous testing requirements that must be completed. The overall test protocol for a modification can be hundreds of pages including guidelines, checklists and test logs to be reviewed and completed before we can turn that modification over to the plant. These testing protocols are overseen by the NRC. Testing requirements include (i) factory testing, (ii) on-site inspection, (iii) post-installation testing, (iv) pre-operational testing and (v) operational testing. After satisfactory completion of operational testing, the modification is turned over to the plant.

C. 2009 Outage

Q. PLEASE PROVIDE AN OVERVIEW OF THE 2009 OUTAGE.

A. The 2009 refueling outage ("RFO 24") was the 24th refueling outage in the plant's history. The 2009 refueling outage began on March 14, 2009, and was scheduled to last for 45 days to April 28, 2009. In total, six modifications scheduled for this outage were completed in 56 days at a cost of $34 million compared to a pre-outage estimate of $25 million. The major modifications completed during the 2009 outage are listed in Table 10.

Table 10: RFO 24 LCM/EPU Completed Modifications

MODIFICATION	DESCRIPTION
High Pressure Turbine Replacement	This modification replaced all rotating and stationary blade sections within the high-pressure turbine to allow greater steam flow capacity.
Low Pressure Turbine Modification	This modification replaced several sections of stationary blades to allow greater steam flow capacity.
Cross Around Relief Valve (CARV) Replacement	This modification replaced the CARV and piping to allow greater flow capacity for EPU operation. In 2009 we removed the original CARVs, installed spares, and shipped the original CARVs to Wiley Labs to reset the set points. The CARV work is included in the feedwater system major modification.
Power Range Neutron Monitoring Installation	Replaced APRM system with the PRNM system.
1AR Transformer	The 1AR transformer was replaced with a new 13.8 kV – 4 kV transformer, equipped with an auto load tap changer. This 1AR transformer work is included in the main power transformer major modification.
Main Steam, Feedwater Piping Modifications and New Instrumentation	Inspected and re-rated #12 Feedwater Heater; Replaced Main Steam Flow Transmitters; Replaced Feedwater Flow Transmitters; Replaced 16 Main Steam Strain Gauges (Stream Dryer Monitoring)

Q. WHO WAS THE PRIMARY INSTALLATION VENDOR DURING THE 2009 OUTAGE?

A. Day Zimmerman was the primary implementation contractor for the 2009 outage. We also requested that General Electric and Shaw provide 24-hour support during the outage as a supplement to their contractual scope of work.

Q. OVERALL, WERE THE 2009 LCM/EPU MODIFICATIONS IMPLEMENTED SUCCESSFULLY?

A. Yes, the 2009 modifications were implemented successfully. The 2009 LCM/EPU projects ran on schedule for the first 75 percent of the outage, but the duration of the LCM/EPU projects ran approximately ten percent over target. We experienced only one lost time accident for a craft worker who injured his elbow.

Q. WHAT WERE THE KEY SUCCESSES FOR THE 2009 OUTAGE?

A. Key successes for the 2009 outage included the installation of the Power Range Neutron Monitoring system, which we installed without operational issues. No other plant in the United States installed this system without initial startup issues. In addition, the installation of the IsoPhase bus modification eliminated a major reliability concern for the plant.

Q. HOW DID THE FINAL IMPLEMENTATION PERFORMANCE COMPARE TO THE ESTIMATED COST AND SCHEDULE FOR THE 2009 OUTAGE?

A. During the 2009 outage we experienced approximately $9 million of implementation costs over our budgeted amount. Virtually all of these additional changes were related to the complexity of the work and difficulty installing the modifications. The majority of these additional costs were attributable to the need for additional labor and materials necessary to complete the work.

Q. WAS ALL OF THE WORK ORIGINALLY SCHEDULED FOR THE 2009 OUTAGE ACTUALLY INSTALLED?

A. No it was not. We deferred a number of modifications to the 2011 outage. Specifically we deferred the condensate demineralizer system replacement and the condensate pump impeller replacement to provide time to complete the design, and we delayed the main transformer because of vendor welding and other fabrication issues. We also deferred some smaller projects to the 2011 outage for better alignment of the work during that outage.

Q. WHY DID THE 2009 OUTAGE EXCEED THE ORIGINAL SCHEDULE BY 11 DAYS?

A. The return to service was delayed by approximately 11 days due to challenges accessing the condenser during installation and startup issues with the turbine and generator at the conclusion of the outage. The high pressure turbine was out of alignment with the generator, and approximately three days were required to bring it into alignment. We required another four days to fully flush the turbine. The installation of the Power Range Neutron Monitor was also delayed because of the need for engineers to technically assist with installation.

Q. DID THE COMPANY PERFORM A REVIEW OF THE 2009 OUTAGE IMPLEMENTATION?

A. Yes we did. The specific lessons learned from LCM/EPU Program in RFO 24 were related to outage planning, on-site assistance from our prime design and engineering vendors, managing scope creep, and setting consistent quality control expectations. While we believed we performed reasonably well during the 2009 refueling outage, we recognized that significantly more work was planned to take place during the 2011 refueling outage. As a result, we wanted to be cognizant of the need to prepare for that work, and we reestablished the outage milestone protocol I discussed above.

Q. WAS THE COMPANY SATISFIED WITH THE OUTCOME OF THE 2009 OUTAGE?

A. Generally, yes. Although the outage milestones were waived in advance of the outage, we were able to take advantage of our design and planning preparation, and we successfully implemented and installed many Program modifications without concern.

D. Implementation Planning, 2009-2011

1. Design and Planning

Q. WHO WAS THE PRIMARY INSTALLATION VENDOR DURING THE 2011 OUTAGE?

A. At the end of the 2009 outage, designs for the 2011 projects were in development and expected to meet the standard outage milestones. To ensure appropriate mobilization and retention of construction supervisors, we retained Day Zimmerman to conduct similar work for the 2011 outage planning period and through the 2011 outage. Day Zimmerman worked with our engineering team to develop work packages for the 2011 outage.

Q. WHAT 2011 OUTAGE PLANNING DIFFICULTIES DID YOU ENCOUNTER?

A. We experienced difficulties with our work package planning for the 2011 outage throughout 2010 and early 2011. We rejected all designs in 2010 and rapidly pursued recovery plans to complete designs that met our specifications. Our efforts to supplement the design process with our internal engineering resources also put pressure on our outage planning.

Although I was personally involved in the decision to select Day Zimmerman and believed they were the best choice to complete the outage work, in my opinion, Day Zimmerman's performance in 2011 was not as strong as I had hoped or expected. Some of these difficulties were attributable to loss of Day Zimmerman's more seasoned planning staff. Our planning was also made more complicated by the fact that we were attempting to modify the electrical system while completing CapX 2020 substation upgrades, which presented an unacceptable shutdown cooling risk.

2. *Decision to Split 2011 Outage*

Q. WHEN DID THE COMPANY DECIDE TO DEFER WORK PLANNED FOR THE 2011 REFUELING OUTAGE AND WHAT FACTORS CONTRIBUTED TO THAT DECISION?

A. The Company decided in June 2010 to split the 2011 outage into two, and defer certain work scheduled for Spring 2011 outage to a Fall 2011 outage. There were three main factors that drove our decision to split the work and add a third outage.

- First, the planned 13.8 kV electrical work presented significant shutdown risk and required intricate work sequence planning. This would have extended the 2011 outage through the summer peak.
- Second, our NRC license amendment request was on hold while the agency resolved the CAP standards.
- Third, vendor fabrication issues with some of the pumps and motors remained unresolved, complicating our outage planning, and posing significant risk of requiring critical path attention throughout the outage.

These issues led us to avoid the unacceptable risk of a prolonged outage through the summer of 2011. The Company elected to allow more time to complete the equipment and design and we planned an off-cycle fall 2011 outage to complete the remainder of the work. Ultimately, other factors led us to postpone the remainder of the work to the regularly-scheduled Spring 2013 refueling outage. We advised the Commission of this change of timing as further described in the testimony of Mr. Alders.

Q. WHAT WORK DID YOU DEFER WHEN YOU DECIDED TO ADD A THIRD OUTAGE?

A. 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 our upgrades to the reactor feed pumps and motors, and the condensate pump and motor, because 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. We also delayed final installation of the 13 A/B feedwater heaters because we were concerned they would not arrive in time for the 2011 outage.

Q. WOULD IT HAVE BEEN FEASIBLE TO COMPLETE ALL REMAINING LCM/EPU PROJECT ACTIVITIES IN THE 2011 OUTAGE?

A. In hindsight, no. We were not sufficiently prepared to undertake all of the activities associated with these major modifications by the Fall of 2011. In fact, we considered deferring more work to a subsequent outage than we did. I believed we could manage the outage as planned and that it was important to the plant to replace the condensate system and the main power transformer sooner than later.

Q. DID THE COMPANY'S DECISION TO SPLIT THE REMAINING WORK INTO TWO OUTAGES RESULT IN AN INCREASE IN PROJECT COSTS?

A. No, I do not believe so. By splitting the outage we allowed ourselves time to complete the design and work planning for the 2013 outage, ensured our vendors met design and quality specifications, and avoided an extended outage during peak electricity demand. The significance of the work scheduled for the third outage required us to begin planning immediately after the 2011 outage and these planning activities continued nonstop until the 2013 outage began. I believe that ultimately, we could not have completed all of the Project work in two outages, and the decision to split the 2011 outage did not materially impact the costs incurred to complete the spring 2011 outage.

E. 2011 Outage

Q. PROVIDE AN OVERVIEW OF THE 2011 OUTAGE.

A. The 2011 refueling outage ("RFO 25") was the 25th refueling outage in the plant's history. The 2011 refueling outage began on March 4, 2011, and was scheduled to last until May 8, 2011, or 65 days. The planned modifications were completed in 81 days, or 16 days longer than planned. The cost of the outage was approximately $133 million compared to an initial estimate of about $101 million.

Q. WHAT PROJECT MODIFICATIONS WERE COMPLETED AS PART OF THE 2011 OUTAGE?

A. During this outage we successfully installed or began six major modifications. These Project modifications are identified in Table 11.

Table 11: RFO 25LCM/EPU Completed Modifications

MODIFICATION	DESCRIPTION
Feedwater Heater Replacement	These original units were over 40 years old and were nearing end of life due to tube degradation. We are one of the few nuclear plants to achieve 40 years of life from our feedwater heaters. The 14 and 15 feedwater heaters were installed in 2011. The 13 feedwater heater replacement was deferred to optimize outage schedule to minimize simultaneous outage work activities in the same area.
13.8 kV Distribution System	Installed cable tray conduit supports, and constructed new switchgear room and new Hot Shop.
Main Transformer Replacement	Replaced the original unit, which was over 40 years old and was nearing end of life due to insulation degradation. Similar to the feedwater heaters, we were able to achieve significantly more years of service from our transformers than other units.
Condensate Demineralizer System and Panel Replacement	The Condensate Demineralizer was deferred from the 2009 outage to 2011 due to added scope and design complexity. The control system upgrade replaced obsolete controls and provided additional margin. The upgrade improved water quality, which will reduce radiation dose for plant maintenance.
Steam Dryer Replacement	Due to evolving NRC licensing requirements and expectations, NSP elected to replace, rather than modify, the steam dryer.
Generator Rewind	Replaced the original insulation on this unit, which was over forty years old and nearing end of life.
11 and 12 Feedwater Heater Drain Line Replacement	The original piping on the drain line was more than forty years old. Approximately half of the linear feet of the original piping was replaced in the Spring 2011 outage. Installation was spread over two outages to minimize impact on outage schedule and labor requirements

Q. HOW DID THE FINAL IMPLEMENTATION PERFORMANCE COMPARE TO THE ESTIMATED COST AND SCHEDULE FOR THE 2011 OUTAGE?

A. During the 2011 outage we experienced about $32.1 million of additional implementation costs above and beyond those estimated for the outage. We expected to complete the 2011 outage in 65 days, but the outage lasted 81 days, 16 days longer than planned.

Q. WHICH MODIFICATION DROVE THE HIGHER THAN ANTICIPATED OUTAGE COSTS IN 2011?

A. The most challenging modification installed in 2011 was by far the condensate demineralizer system. Our costs to install this modification during the 2011 outage exceeded our installation estimate by approximately $13 million. The condensate demineralizer system posed three particular difficulties that we also faced to varying degrees with other modifications during the 2011 outage. Those difficulties related to as-found conditions in the plant, challenges completing the work within the confined spaces of the plant and difficulties sequencing the work.

First, while preparing for the work, we identified that the condensate demineralizer vessel vaults were radiological. To mitigate the risk to plant workers, we were forced to add shielding to the location and further plan the work to minimize the exposure to our workers. Similarly, while preparing to install new digital controls for the condensate demineralizer system, we identified that existing wiring for the controls was degraded and required replacement. Thus, we were forced to quickly plan for and replace this wiring before proceeding with the rest of the work. We were unable to access this wiring before the start of the 2011 outage.

Second, the condensate demineralizer system work required replacement of all vessels and associated piping. This piping is located in a very small space. When coupled with the high-dose environment we found in this location, only a small number of workers could work simultaneously in this area. That substantially limited our ability to complete the work as efficiently and expeditiously as we expected.

Third, because of the complexity of the condensate demineralizer system modification, we were not able to complete all of the detailed scheduling and sequencing with other outage activities until just prior to the start of the outage. That delay substantially limited our opportunity to optimize the sequencing of the work. As a result, we encountered difficulties with overlapping activities that delayed portions of the work.

Q. ARE THERE OTHER EXAMPLES OF CHALLENGES FACED DURING THE 2011 OUTAGE THAT CONTRIBUTED TO HIGHER THAN ANTICIPATED COSTS?

A. Yes. For example, we expanded the budgeted scope of work for Sargent & Lundy to assist with challenges faced with work on the main transformer and switchyard. We also experienced a malfunction with a steam dryer seal on top of the reactor vessel. This malfunction led to roughly four days of delay for the steam dryer replacement modification. We incurred approximately $2 million in excess of our initial steam dryer installation estimate.

F. Implementation Planning, 2011-2013

1. Decision to Move Final LCM/EPU Implementation Outage to 2013

Q. WHEN DID THE COMPANY DECIDE TO IMPLEMENT THE FINAL PROJECT OUTAGE IN 2013?

A. In November 2011 we elected to move the final outage to spring 2013. This allowed us to synchronize the final implementation outage with our scheduled refueling outage and the NRC's review of our license amendment request.

Q. WHY DID THE STATUS OF THE NRC'S LICENSE REVIEW CONTRIBUTE TO THE DECISION TO FURTHER DELAY THE OUTAGE?

A. We initially expected to receive NRC EPU approval in 2009, and we were planning to complete the physical work and operate at the higher output levels as quickly as possible. When the NRC put our review on hold to address the CAP issue, we realized we would not receive the license as soon as we had hoped, but it allowed us some breathing room so we could defer final installations without foregoing project benefits. It initially looked as though we had a work-around to the CAP issue developing so we thought the off-cycle outage in 2011 might be valuable. As things developed, however, it became clear that the license would be delayed a significant time and it allowed us to complete our preparations for the final outage and move it to 2013.

Q. PLEASE DESCRIBE THE VENDOR PERFORMANCE ISSUE THE COMPANY CONSIDERED IN ULTIMATELY DECIDING TO DELAY THE FINAL PROJECT IMPLEMENTATION OUTAGE TO THE SCHEDULED REFUELING OUTAGE IN 2013.

A. We had one piece of equipment that did not perform up to the Company's design specification and had to be adjusted. We initially attempted to find other solutions around the design but concluded there were none. The refurbishment schedule required a significant delay in the outage, an estimate that lengthened as we learned more regarding the solution. This issue was resolved satisfactorily and resulted in a partial settlement under which the equipment was redesigned to meet the specifications and Xcel Energy received a discount for other payment obligations.

2. Lessons Learned

Q. WHAT DID THE COMPANY DO IN RESPONSE TO THESE CHALLENGES?

A. During the 2011 outage we recognized the need to adapt our processes and we took steps so we could immediately continue planning for the 2013 outage. After the 2011 refueling outage, the Company undertook a project management assessment. The Projects group conducted a post-outage critique and identified a number of improvement opportunities. Actions related to staffing, construction estimates, design process, safety education, spare parts inventory, project controls and cost tracking were proposed to assist the program team in managing a project of this scale. The Company undertook a comprehensive effort to strengthen the Program's organization and the project management practices in place for the planning and execution of the 2013 outage.

Q. DID THE COMPANY MAKE ANY SIGNIFICANT CHANGES IN THE WAY THE FINAL OUTAGE WOULD PROCEED?

A. Yes. One of our most important recognitions from review of the 2011 outage, was the final modifications scheduled for the 2013 outage would be the most challenging installations of the Project. In mid-2011 we elected to hire Bechtel Power Corporation ("Bechtel") to provide comprehensive project management to ensure successful completion of the final LCM/EPU modifications. Bechtel is a large and sophisticated multi-national company with expertise in the area of nuclear generation. A profile of Bechtel is provided in Exhibit ___ (TJO-1), Schedule 16.

Q. WAS THE DECISION TO USE BECHTEL FOR THE FINAL IMPLEMENTATION OUTAGE REASONABLE?

A. Yes. 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. However, as I will discuss below, even with Bechtel on board and with substantial time to develop the work packages and sequence planning for the 2013 outage, the difficulty of the work caused the 2013 outage to exceed its initial and revised budget and schedule as well.

Q. WHAT OTHER STEPS DID THE COMPANY TAKE AT THE CONCLUSION OF THE 2011 OUTAGE TO IMPLEMENT THE LESSONS IT LEARNED?

A. We hired Karen Fili in December 2011 as Vice President-Nuclear Projects to reorganize the capital projects organization within the nuclear business unit. Ms. Fili is a highly-experienced project specialist with extensive experience implementing major capital projects for other nuclear utilities. The Company concluded that we would benefit from her experience with successfully implementing rigorous project management controls.

Q. PLEASE SUMMARIZE MS. FILI'S EFFORTS TO REORGANIZE THE NUCLEAR CAPITAL PROJECTS GROUP.

A. Ms. Fili took a number of steps, including: (1) realigning the projects' group structure; (2) emphasizing individual modification budgeting and forecasting; and (3) establishing firm outage milestones. In addition, she instituted a set of processes to improve reporting and tracking.

Q. DID THESE PROJECT MANAGEMENT TOOLS RESULT IN COST SAVINGS?

A. Not necessarily. Nuclear projects tend to be difficult and expensive, and the use of rigorous project controls cannot change the need to undertake the work necessary to satisfy the relevant NRC requirements and to otherwise complete the work. Certainly more detailed planning and reporting may help to avoid delays; however, our experience was that while we had a clearer picture of our costs and schedule, we were not able to keep costs from increasing and, in the end, the costs we incurred were necessary to complete the modifications successfully.

3. Preparation for 2013 Outage

Q. IN PREPARING FOR THE FINAL OUTAGE, DID THE COMPANY REVISIT ITS ESTIMATES OF PROGRAM COSTS?

A. Yes. The Company took time to develop the final cost estimates for the 2013 outage to try to understand the complexities of the Program. We received estimates from Bechtel as part of this effort in mid-2011. We formally reviewed and evaluated those estimates, and requested refined estimates. By the end of 2011 Bechtel had arrived at an estimate for total project costs of $586.7 million. This estimate was the basis for our estimated project costs of $586.7 million provided in our 2012 rate case, Docket No. E002/GR-12-961.

Q. DID BECHTEL AND THE COMPANY CONTINUE TO REFINE THE ESTIMATE?

A. Yes. Bechtel worked through several iterations and a final Program estimate was not approved until January, 2013 and then updated in June 2013.

Q. WHAT WAS THE REVISED COST ESTIMATE FOR PROGRAM COMPLETION WHEN THE OUTAGE BEGAN?

A. The January 2013 estimate for the complete LCM/EPU Program was $639.9 million. The $639.9 million estimate included $20 million in contingency. By June 2013, an additional $15 million of costs were added for the LCM/EPU Program to arrive at a final forecast of $655 million.

Q. WHY DID YOU INCLUDE A $20 MILLION CONTINGENCY IN THE PROGRAM COST ESTIMATE DEVELOPED IN FEBRUARY 2013?

A. Contingencies in cost estimates are necessary to capture the risk of unknowns in a project. This allowance is used to communicate to our executive management and other internal stakeholders that although we have done our best to capture the full cost of the LCM/EPU Program, initiatives of this scale routinely present some risk. The amount of the contingency is our best estimate of that risk.

Q. DOES THE USE OF A CONTINGENCY DEPART FROM PAST PRACTICE ON THE LCM/EPU PROGRAM?

A. Yes. Previously the Company elected not to include contingencies or other types of more general risk allowances in its estimates.

Q. WHAT WAS THE FINAL SCHEDULE FOR THE 2013 OUTAGE, AND HOW WAS IT DEVELOPED?

A. A comprehensive outage schedule for each modification was developed using an industry standard software package known as Primavera P6®. This outage schedule was extremely aggressive and scheduled all of the work to be completed within 87 days. While this was the goal, the Company recognized it was unlikely we could get everything done in that period of time. As a result, for internal planning purposes, the Company assumed that the outage would take 100 days to complete.

Q. DID YOU HAVE ANY EQUIPMENT ISSUES AS YOU APPROACHED THE 2013 OUTAGE?

A. Yes. One of the new reactor feed pumps was damaged during testing in 2012. Repairs to the pump were made at the vendor's cost but the repairs and testing were not completed until December 2012. The pumps were delivered in time for installation.

G. 2013 Outage

Q. PLEASE DESCRIBE THE 2013 IMPLEMENTATION OUTAGE.

A. The 2013 refueling outage, RFO 26, began on March 2, 2013, and was completed on July 18, 2013, for a total duration of 138 days, or 53 days longer than the targeted schedule and 38 days longer than the final budget schedule. We incurred $151 million for the installation of the 2013 Project modifications, which was $52 million over our initial budget excluding contingency.

Q. DO THE 2013 OUTAGE RESULTS MEAN THAT THE CHANGES YOU INSTITUTED AFTER THE 2011 OUTAGE WERE UNSUCCESSFUL?

A. No. I believe the changes we made closed several gaps we identified after the 2011 outage. The 2013 outage results do illustrate, however, the difficulty of containing costs even with substantial time and effort because of the complexity of the work undertaken.

Q. WHAT MODIFICATIONS WERE COMPLETED DURING THE 2013 OUTAGE?

A. We completed six major LCM/EPU modifications during the 2013 outage. Table 12 describes the modifications and a brief description of the 2013 modifications.

Table 12: RFO 26 LCM/EPU Completed Modifications

MODIFICATION	DESCRIPTION
13.8 kV Distribution System	The 13.8 kV switchgear was installed and the 1R and 2R Transformers were replaced during the 2013 outage. Among the tasks this included construct a new switchgear room along with all of the associated bus work. We had to pull over 14 miles of cable and raceway.
Condensate Pump and Motor Replacement	Two condensate pumps and two motors were replaced during the 2013 outage. The new pumps are designed to be driven by 2400 HP 13.8 kV motors, and deliver 9100 gpm to support the required EPU conditions.
Feedwater Heater Replacement	Two of six feedwater heaters, the 13 A/B series, and associated components were replaced during the 2013 outage.
Reactor Feed Pump Replacement	Two reactor feed pumps, two reactor feed pumps, piping and associated components were replaced during the 2013 outage.

MODIFICATION	DESCRIPTION
Reactor Water Cleanup System Modification	The reactor water cleanup (RWCU) system is used to filter undesired particles from being circulated through the feedwater system. The RWCU pumps and motors were replaced during the 2013 outage.
PCT Vent and Purge Valve	This small modification was completed successfully

Q. WHAT COSTS WERE INCURRED TO INSTALL THE FOUR MAJOR MODIFICATIONS DURING THE 2013 OUTAGE?

A. Table 13 summarizes the actual installation costs during RFO 26 for the major modifications.

Table 13. 2013 Installation – Major Modifications

MODIFICATION	MILLION $	
	BUDGETED AMOUNT	ACTUAL 2013 OUTAGE COST
13.8 kV System Addition	$43.4	$57.3
Condensate Pumps and Motors Replacement	$5.1	$10.5
Feedwater Heater Replacement	$17.8	$25.6
Reactor Feed Pumps and Motors Replacement	$24.8	$43.8
Total	$91.1	$137.2

Q. WHAT CHALLENGES DID XCEL ENERGY ENCOUNTER DURING THE 2013 REFUELING OUTAGE THAT ULTIMATELY AFFECTED THE OUTAGE COST AND SCHEDULE?

A. Xcel Energy faced several challenges during RFO 26. The most significant implementation challenges related to the 13.8 kV electrical system upgrade and the reactor feed pump replacement. The primary issue contributing to the extended outage duration for the feed pump replacement was the lack of space considerations. 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. 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.

The electric cable we had to pull was more than two inches in diameter and weighed in excess of 100 pounds per foot. Teams of ten electricians were required to pull the cable through the conduit. This task required care and precision to avoid overtensioning and damaging the cables as they were being pulled.

We also experienced delay in completing the testing for the 13.8 kV and feed pumps after installation. The last three weeks of the outage were spent testing the feed pumps and the 13.8 kV system additions.

In addition to the technical implementation challenges we faced during the 2013 outage, we also encountered lower productivity than we anticipated.

Q. WHAT DO YOU MEAN WHEN YOU SAY YOU EXPERIENCED LOWER THAN EXPECTED PRODUCTIVITY?

A. Productivity refers to the pace of work completion relative to our initial expectation. There were several contributors to our lower than anticipated productivity. First, we had challenges hiring experienced craft labor due to the competitive nuclear labor market. Second, many of the tasks took longer than we had estimated due to the difficulty of workers being restricted due to radiological conditions or small work spaces. Third, we lost experienced workers as a result of the current market for craft labor and the NRC worker fatigue rule. Additionally, we had some concerns over the management of some of the tasks and are currently investigating those concerns and have begun a dialogue with our contractors to resolve them.

Q. WHAT FACTORS CONTRIBUTED TO THE LABOR SHORTAGE?

A. The demand for workers in the nuclear power industry, particularly those with major project experience, coupled with the declining supply of such workers made it acutely difficult to staff our project and maintain that staffing throughout the duration of the project. This combination of trends contributed to the difficulties we experienced on the Monticello LCM/EPU Program. In addition, we experienced difficulties in hiring and retaining experienced craft labor for the outages and lost experienced workers to competing jobs in other industries that do not have the types of work place restrictions that exist at a nuclear power plant.

The NRC's "fatigue rule" also impacted the 2013 outage. The NRC introduced new rules and guidance related to "fatigue management for nuclear power plant personnel," under 10 CFR Part 26. This guidance reduced the number of hours that can be worked by individual employees at our nuclear facilities. As a result, we were required to retain additional workers to comply with this rule change. While we anticipated the reduction in hours, we did not anticipate the significant loss of contractors and associated productivity.

Q. WHAT WAS THE PRACTICAL IMPACT OF THE FATIGUE RULE ON THE WORK EFFORT?

A. In the construction trades, a large project will sometimes deploy its workforce on a 12 hour by 7 day schedule. Many workers prefer this schedule as it maximizes their earning potential during the job. The fatigue rule effectively limits workers to a six-day per week schedule. This created a competitive disadvantage to the extent that we had to compete for workers with other projects that do not have to comply with the fatigue rule.

As it relates to our refueling outages, our employees are permitted to work extended hours, subject to certain conditions, for the first 60 days of the outage. On the sixty-first day of the outage, we are required to meaningfully limit those hours to comply with NRC regulations. That requirement was implemented by the NRC to make certain our workers were able to diligently complete their duties following prolonged periods of extended hours. Nevertheless, the requirement does limit the hours that can be worked by an individual worker and forces the licensee to use additional workers to shorten the duration of the refueling outage.

Both the lack of skilled labor, the impacts of the NRC fatigue rule, and other vendor issues as described in this filing, all served to lower actual productivity compared to the levels we had budgeted.

VII. MAJOR MODIFICATIONS

Q. WHAT WERE THE MAJOR MODIFICATIONS THAT WERE INSTALLED AS PART OF THE LCM/EPU PROGRAM?

A. The Monticello LCM/EPU Program included ten major modifications that account for approximately 95 percent of the total Program costs. Table 14 identifies the major modifications, work order numbers, in-service years, and total modification costs.

Table 14. Major Modifications Summary Table

Major Modification		Child Work Order Numbers	Year In-Service	Total Costs (million $)	% of Total Program Costs
1	Turbine Replacement	11133668	2009 and 2011	$57.5	8.64%
		11335729			
2	Power Range Neutron Monitor	10942850	2009	$17.5	2.64%
3	Steam Dryer	10859413	2011	$37.7	5.66%
		11215274			
4	Condensate Demineralizer System	11133705	2011	$79.8	12.00%
5	Main Transformer	10943007	2009 and 2011	$29.9	4.50%
		10735617			
6	Feedwater Heaters	11638897	2009, 2011, and 2013	$114.9	17.29%
		11842626			
		11133719			
		11284286			
		11757884			
		11286961			
		11133856			
		11133713			
7	Reactor Feed Pumps and Motors	11286955	2013	$92.2	13.86%
8	Condensate Pumps and Motors	10943052	2013	$21.9	3.29%
		11845189			
9	13.8kV	11257804	2013	$119.5	17.98%
10	Licensing	11536446	2013 2014*	$59.3	8.92%
		11636097			
		11636101			
		11636105			

Major Modification		Child Work Order Numbers	Year In-Service	Total Costs (million $)	% of Total Program Costs
		11636109			
		11636114			
		11775097			
Total of Major Modifications				**$630.2**	**94.77%**

* Based on anticipated final NRC approval dates

This table reflects the allocation of common costs to the various modifications. We grouped certain work orders by the major modification to which they are related. We also added licensing and the power range neutron monitor as major modifications as these additions capture nearly 95 percent of the LCM/EPU Program costs. Likewise, we attempted to provide a more thorough reflection of our initial cost estimates by allocating common costs estimated to be incurred at that time.

Below, I provide a discussion of each of the ten major modifications, in chronological order according to when the modifications were placed in service. Although Licensing is discussed elsewhere in my testimony to provide context for schedule changes we include the explanation of costs in this section. Below, I explain the initial and final scope of the ten modifications, an overview of the engineering and design process, major modification components and the modification installation, the initial cost estimate for the modification, and the final cost of the modifications. I also provide an explanation of the modification challenges and cost drivers that caused costs to be incurred in excess of the initial estimates.

The remaining modifications that make up approximately five percent of the Project costs are discussed in Section VIII of my testimony.

A. Major Modifications – Turbine Replacement

Q. WHAT WAS THE TURBINE REPLACEMENT MODIFICATION?

A. The turbine replacement modification was completed during the 2009 outage (turbine) and 2011 outage (vibration monitoring) at a total cost of approximately $57.5 million (Work Order Nos. 11133668 and 11335729). The modification included the replacement of the existing high-pressure turbine steam path with a new rotor and new diaphragms to accommodate increased steam flow. The modification also included changes to the low-pressure turbine, including replacement of several diaphragm sets, one set of blades, and replacement of selected casing bolts. As part of the modification, we also evaluated and replaced the expansion joints, where necessary. Finally, the modification included the installation of a new vibration monitoring system.

A summary of the scope and photos of the turbine replacement modification can be found in Exhibit ___ (TJO-1), Schedule 19.

Q. WHAT ARE THE TURBINES AND HOW ARE THEY IN USE AT MONTICELLO?

A. The high- and low-pressure turbines at Monticello convert steam to mechanical energy and turn the generator. The steam enters the turbines and passes through a series of blades, sometimes called "buckets." These buckets are attached to a central shaft or rotor that is mechanically connected to the generator. The shape of the blades allow pressurized steam to push against the blades and turn the rotor, that then turns the generator.

Q. WHAT WAS THE INITIAL SCOPE AND COST ESTIMATE FOR THE TURBINE REPLACEMENT MODIFICATION?

A. The initial cost estimate for the turbine replacement modification was $60.2 million. This estimate included high-pressure advanced steam path turbine redesign, replacement of stages 8 and 10 of the low-pressure turbine, and modifications for changes in valve operating requirements of the cams and camshafts. Equipment for a turbine vibration monitoring system was also included in the initial estimate.

Q. DID THE SCOPE FOR THIS MODIFICATION CHANGE SUBSTANTIALLY BETWEEN 2006 AND INSTALLATION?

A. No it did not.

Q. WHY WAS THE TURBINE MODIFICATION REQUIRED FOR THE LCM/EPU PROGRAM?

A. The previous high-pressure turbine required replacement or significant annual maintenance to support long-term operations at Monticello. We replaced the high- and low-pressure turbines in 1996. The turbines would have required replacement or refurbishment to enable Monticello to operate until 2030.

Additionally, the steam flow under EPU conditions necessitated replacing the high-pressure turbine steam path and portions of the low-pressure turbine. A 2004 feasibility study provided an initial evaluation of two options to address the turbine modification – turbine replacement or a reheat cycle to address limitations in the flow passing capability of the existing high-pressure turbine.

We opted to pursue a turbine replacement. Turbines need to be inspected periodically and as they age, they frequently need repair for cracked blades. Based on the overall age of the turbine and our experience and that of the industry, we determined that it was better to replace the turbine as part of the LCM/EPU initiative.

Q. WHAT WAS THE ACTUAL SPENDING ON THE TURBINE REPLACEMENT MODIFICATION?

A. As shown below, we incurred approximately $57.5 million to complete this modification. The turbine modification was completed for less than our budgeted amount. Table 15 provides our cost estimate for the turbine replacement modification by major cost category.

Table 15. Turbine Replacement Cost by Category (Million $)

Turbine Replacement	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1
Design/Engineering	$0.0	$0.0	$0.0	$0.0	$0.0	$3.1	$0.4	$0.1	$0.0	$0.0	$3.5
Materials/Components	$0.0	$0.0	$0.0	$0.0	$0.0	$31.6	$0.3	$0.0	$0.0	$0.0	$31.9
Installation	$0.0	$0.0	$0.0	$0.0	$0.0	$2.8	$0.1	$1.5	$0.0	$0.0	$4.4
Common	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$17.2	$0.0	$0.0	$17.2
Xcel General Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	$0.0	$0.1	$0.0	$0.0	$0.3
Total	$0.0	$0.0	$0.0	$0.0	**$0.0**	**$37.6**	**$0.8**	**$19.0**	**$0.0**	**$0.0**	**$57.5**

* Child Work Orders - 11133668 - MNGP EPU Turbine Replacement, 11335729 - MNGP EPU Turbine Generator Vibration

Q. IF THE TURBINE INSTALLATION WAS COMPLETED IN 2009 AND THE VIBRATION MONITORING EQUIPMENT WAS INSTALLED IN 2011, WHY ARE THERE NO "COMMON" COSTS ALLOCATED TO THE MODIFICATION IN 2009?

A. In 2011, we reviewed the common costs incurred during the LCM/EPU Program, and we assigned and allocated common costs to modifications placed in service in 2009 and 2011, including for the turbine installation.

Q. IS THE FINAL COST OF THE MONTICELLO TURBINE REPLACEMENT MODIFICATION CONSISTENT WITH INDUSTRY-ANTICIPATED COST FOR A SIMILAR PROJECT?

A. Yes. Many utilities have replaced their high- and low-pressure turbines due to wear or a desire to achieve additional station output. A list of other nuclear plants that have replaced turbines is provided at Exhibit ___ (TJO-1), Schedule 20.

B. Major Modifications – Power Range Neutron Monitoring System

Q. WHAT WAS THE POWER RANGE NEUTRON MONITORING SYSTEM MODIFICATION?

A. The power range neutron monitoring system modification was completed during the 2009 outage at a total cost of approximately $17.5 million (Work Order No. 10942850). The modification included design, engineering, and installation of a GE Nuclear Measurement Analysis and Control power range neutron monitoring system to replace the station's old power range neutron monitoring systems. The modification also included an upgrade of the Plant Process Computer to a state-of-the-art processing system. The nuclear measurement analysis and control power range neutron monitoring system uses the same in-core detectors as the old system, but replaces all of the electronics and associated power supplies. This modification required replacement of certain control room panel components and installation of new fiber optic cables.

A summary of the power range neutron monitoring system modification can be found in Exhibit ___ (TJO-1), Schedule 21.

Q. WHAT WAS THE INITIAL SCOPE AND COST ESTIMATE FOR THE POWER RANGE NEUTRON MONITORING SYSTEM MODIFICATION?

A. The initial cost estimate for the turbine replacement modification was $15.7 million (2008$). This scope included design, engineering, and installation of the power range neutron monitoring system.

Q. DID THE SCOPE FOR THIS MODIFICATION CHANGE SUBSTANTIALLY OVER THE COURSE OF THE LCM/EPU PROGRAM?

A. No, it did not.

Q. WHAT IS THE POWER RANGE NEUTRON MONITORING SYSTEM, AND HOW IS IT IN USE AT MONTICELLO?

A. The power range neutron monitoring system is required to support plant operation at the currently-authorized power level and at the EPU power level once approved. The new power range neutron monitoring system allows us to better monitor the number of neutrons available for further fission reactions. The power range neutron monitor employs in-core neutron detectors to monitor local reactivity for core monitoring purposes. The power range neutron monitoring system provides output to the Reactor Protection System to allow for timely initiation of reactor trips, rod blocks and alarms, and communicates data to the core monitoring computer and other station systems.

Q. WHY WAS THE POWER RANGE NEUTRON MONITOR REQUIRED FOR THE LCM/EPU PROGRAM?

A. The power range neutron monitor is the upgraded, digital replacement for the plant's old average power neutron monitor and oscillation power range monitor systems, which were aged and presented obsolescence and spare parts issues. The power range neutron monitor installation was also necessary to support operations in the MELLLA+ operating region. In addition to supporting EPU operations, the system is expected to improve reliability and has alleviated the need to continually test and monitor the average power neutron monitor system.

Q. WHAT WAS THE ACTUAL SPENDING ON THE POWER RANGE NEUTRON MONITORING SYSTEM MODIFICATION?

A. Table 16 provides our cost for the modification by major cost category. We incurred approximately $17.5 million to complete this modification.

Table 16. Power Range Neutron Monitoring System Cost by Category (Million $)

Power Range Neutron Monitoring System	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$0.0	$0.0	$0.0	$0.0	$0.3	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.2
Design/Engineering	$0.0	$0.0	$0.0	$0.5	$1.6	$1.7	($0.0)	$0.0	$0.0	$0.0	$3.8
Materials/Components	$0.0	$0.0	$0.0	$0.0	$0.1	$4.9	($0.3)	$0.0	$0.0	$0.0	$4.7
Installation	$0.0	$0.0	$0.0	$0.0	$0.0	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5
Common	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$5.3	$0.0	$0.0	$5.3
Xcel General Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.1
Total	$0.0	$0.0	$0.0	$0.0	**$2.0**	**$10.0**	**($0.3)**	**$5.3**	**$0.0**	**$0.0**	**$17.5**

* Child Work Orders - 10942850 - MNGP EPU-Power Range/Neutron Monitoring System

Q. IF THE POWER RANGE NEUTRON MONITORING SYSTEM INSTALLATION WAS COMPLETED IN 2009, WHY ARE THERE "COMMON" COSTS ALLOCATED TO THE MODIFICATION IN 2011?

A. Similar to the turbine modification, in 2011, we reviewed the common costs incurred during the LCM/EPU Program, and we assigned and allocated common costs to modifications placed in service in 2009 and 2011, including this modification.

Q. WHY DID THE FINAL COST FOR THE POWER RANGE NEUTRON MONITOR MODIFICATION EXCEED THE INITIAL ESTIMATE?

A. We estimated this work would cost approximately $15.7 million (2008$) when we initiated implementation of the Program. The power range neutron monitoring system required substantial development and implementation of pre-operational and modification acceptance tests, the primary contributors to the $2 million increase between the initial estimate and final cost.

Q. DID THE COMPANY ENCOUNTER CHALLENGES DURING THE DESIGN AND INSTALLATION OF THE MODIFICATION?

A. We encountered few difficulties with this modification. Notably, we installed the power range neutron monitoring system without start-up issues, which no other nuclear plant in the United States has done. Other nuclear facilities encountered operational impacts after the installation of similar systems. As a result of application of lessons learned from other facilities we were the first plant to successfully restart the power range neutron monitor without experiencing the difficulties faced by other operators.

Q. WHAT BENEFITS DOES THE NEW POWER RANGE NEUTRON MONITORING SYSTEM PROVIDE TO MONTICELLO?

A. The new power range neutron monitor is installed and supporting current plant operation by providing additional stability functions and additional trip capability. The power range neutron monitoring system upgrade provides operation and maintenance benefits in terms of improved system reliability and reduced surveillance and testing requirements.

C. Major Modifications – Steam Dryer

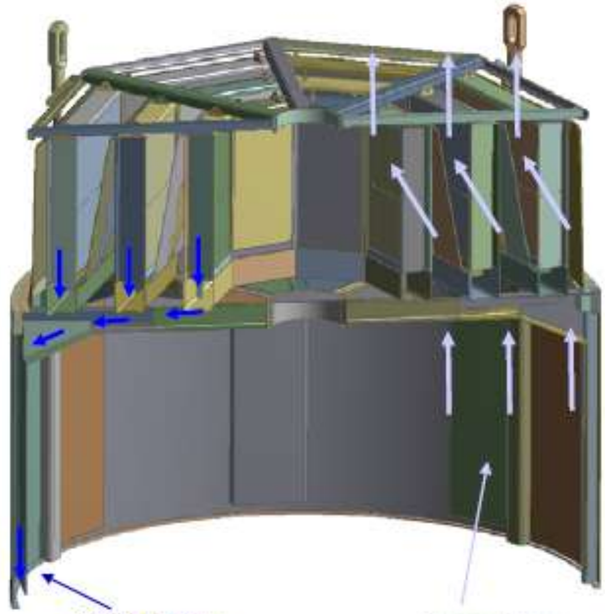
Q. PLEASE DESCRIBE THE STEAM DRYER MODIFICATION PROJECT.

A. The steam dryer modification occurred from 2007 through 2011 at a total cost of approximately $38 million. The actual replacement of the steam dryer occurred during the 2011 outage, and the monitoring and evaluation of the steam dryer occurred in 2007 and 2008. The work for the steam dryer modification is included in Work Orders 10859413 and 11215274. A summary of the steam dryer modification and photos of its installation are provided in Exhibit ___ (TJO-1), Schedule 22.

Q. WHAT IS THE STEAM DRYER, AND WHAT IS ITS PURPOSE AT MONTICELLO?

A. The steam dryer is a large metal structure placed at the top of the reactor. The steam dryer consists of metal plates. The steam formed in the reactor is forced through these plates to reduce the liquid water content of the steam. This steam is transferred from the reactor to the high and low pressure turbines. The steam dryer reduces moisture content of the steam produced from the reactor to minimize wear on the high and low pressure turbine blades. A schematic that illustrates the steam dryer function is provided in Figure 3.

Figure 3. Steam Dryer Schematic



Q. WHY WAS THE STEAM DRYER MODIFICATION NECESSARY FOR THE LCM/EPU PROGRAM?

A. The original steam dryer was designed in the mid-1960s. Over time, its operability decreased and moisture carryover was marginally acceptable at the time we began planning for the LCM/EPU Program. The adequacy of the moisture reduction presented further concern under EPU conditions. We were also concerned whether the existing dryer could withstand the increased vibrations that would result from EPU operating levels.

The Company initially believed modifications to the steam dryer would address these operational concerns. In 2007, we installed sensors in the steam lines to gather baseline data for analysis. Concurrent with our design of this modification, we learned of cracking in other units' steam dryers. As a result, the NRC issued guidance that would have required additional inspections and, in all likelihood, significant repairs for steam dryers over 40 years of age. It became apparent that replacement of the steam dryer was necessary to support long-term station operations whether or not we completed the EPU and in late 2007, GE recommended we replace, rather than modify, the existing steam dryer.

Q. WHAT WAS THE ORIGINAL ESTIMATE FOR THE REPLACEMENT STEAM DRYER?

A. We initially estimated replacement of the steam dryer at a cost of $35.9 million (2008$).

Q. WHAT WAS THE FINAL COST OF THE STEAM DRYER REPLACEMENT MODIFICATION?

A. The total cost of the steam dryer replacement modification was approximately $38 million. Table 17 summarizes the costs incurred for the steam dryer modification.

Table 17. Steam Dryer Modification Cost Categorization Summary (Million $

Steam Dryer	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Design/Engineering	$0.0	$0.0	$0.0	$3.5	$1.0	$4.1	$0.9	$1.1	$0.1	$0.0	$10.7
Materials/Components	$0.0	$0.0	$0.0	$0.0	$0.0	$8.5	$3.3	$8.3	$0.0	$0.0	$20.1
Installation	$0.0	$0.0	$0.0	$0.0	$0.0	$0.4	$0.7	$3.9	$0.0	$0.0	$5.0
Common	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2.2	$0.0	$0.0	$2.2
Xcel General Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-$0.3	$0.0	$0.0	-$0.3
Total	**$0.0**	**$0.0**	**$0.0**	**$3.5**	**$1.0**	**$13.0**	**$4.9**	**$15.2**	**$0.1**	**$0.0**	**$37.7**

* Child Work Orders 10859413 - MNGP EPU Steam Dryer Acoustic Monitoring, 11215274 - EPU Steam Dryer Replacement

Q. WHY DID THE STEAM DRYER MODIFICATION COST MORE THAN THE INITIAL ESTIMATE?

A. Our final cost exceeded our initial estimate by approximately $2 million. The primary driver for this increase is the installation of sophisticated acoustic monitoring instrumentation. We installed this monitoring in response to the

NRC's concerns over steam dryer failures at other facilities. We will use the outputs from this acoustic monitoring to avoid similar incidents. Although it comprised a smaller portion of the overall modification cost, specialized craft labor was required to install this monitoring equipment.

Q. HOW HAS THE STEAM DRYER REPLACEMENT IMPROVED OPERATION AT MONTICELLO?

A. The steam dryer efficiently removes the moisture from the steam produced by the reactor and provides high-quality steam to the turbine. The new steam dryer is reducing moisture carryover to no more than 0.1 percent. This reduction in moisture carryover minimizes corrosion products in the reactor coolant loop, which in turn minimizes impacts to the turbine blading, and reduces the volume of radioactive wastes.

D. Major Modifications – Condensate Demineralizer

Q. PLEASE PROVIDE AN OVERVIEW OF THE CONDENSATE DEMINERALIZER MODIFICATION PROJECT.

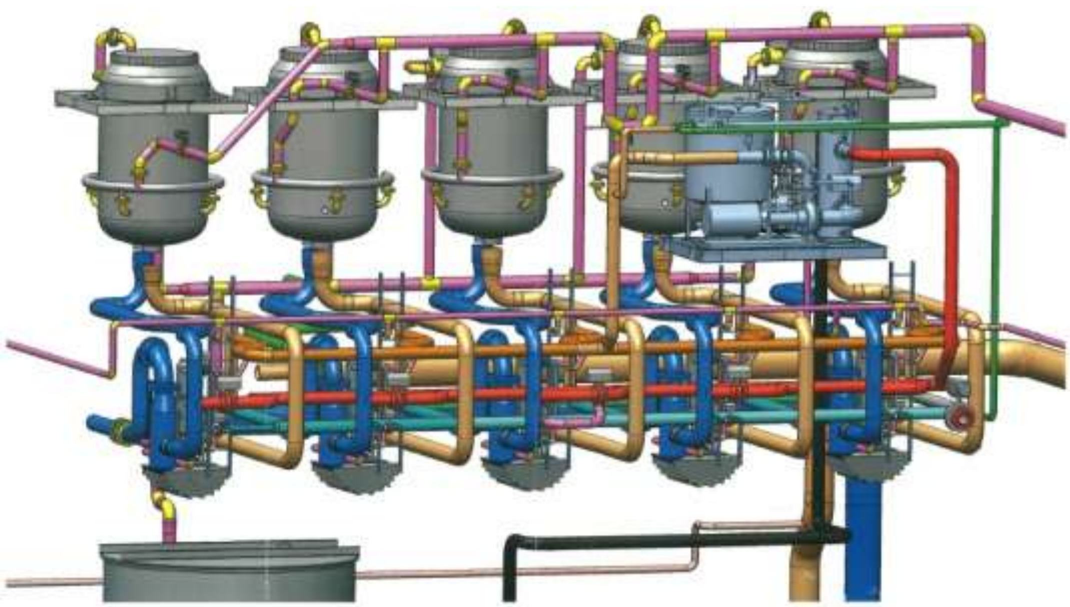
A. The condensate demineralizer modification was installed during the 2011 refueling outage at a cost of $79.8 million (Work Order No. 11133705). This modification included the replacement of the entire condensate demineralizer system, including the five vessels, skid-mounted pre-coat system, holding pumps, associated piping, valves, and support systems. The modification also included replacing the existing analog control system with a digital control system and installation of a new motor control center.

A detailed summary, schematic drawings, and photos of the condensate demineralizer modification can be found in Exhibit ___ (TJO-1), Schedule 23.

Q. WHAT IS THE CONDENSATE DEMINERALIZER SYSTEM, AND HOW IS IT IN USE AT MONTICELLO?

A. The condensate demineralizer provides clean, de-aerated, and pre-heated water to the reactor during normal plant operation. The system consists of five large stainless steel vessels that filter the water before it flows to the reactor or reverse flow. The vessels are housed in concrete vaults. A control system is in place to manipulate the valves, control the amount of water flowing through and from the system, and maintain water chemistry for optimum operation. Backwashing of the condensate vessels is required every several days to remove ion exchange resin that accumulates in the filter. A schematic of the condensate demineralizer system illustrating the vessels and the auxiliary piping is provided in Figure 4.

Figure 4. Condensate Demineralizer Equipment Schematic



Q. WHAT SCOPE OF WORK WAS INCLUDED IN THE INITIAL ESTIMATE FOR THE CONDENSATE DEMINERALIZER MODIFICATION AND AT WHAT COST?

A. Our 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. This work was estimated to cost $18.0 million (2008$).

Q. DID THE SCOPE OF THE CONDENSATE DEMINERALIZER MODIFICATION CHANGE SUBSTANTIALLY?

A. Yes. The final scope for the condensate demineralizer modification grew substantially once we 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. The initial scope did not account for preexisting conditions that caused the operability and performance concerns. This additional scope component drove a substantial portion of our cost increase.

Q. WHAT WAS THE ACTUAL SPENDING ON THE CONDENSATE DEMINERALIZER MODIFICATION?

A. We incurred approximately $79.8 million to complete the condensate demineralizer system modification. We incurred approximately $28.2 million, or 35 percent, of our costs for design and engineering services and approximately $32.1 million, or 40 percent, for installation of this modification. Table 18 provides our cost for the condensate demineralizer project by major cost category.

Table 18. Condensate Demineralizer System Cost by Category (Million $)

Condensate Demineralizer	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Design/Engineering	$0.0	$0.0	$0.0	$0.0	$0.0	$1.0	$0.7	$26.5	$0.0	$0.0	$28.2
Materials/Components	$0.0	$0.0	$0.0	$0.0	$0.0	$1.8	$0.3	$1.6	$0.0	$0.0	$3.7
Installation	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	$1.2	$30.3	$0.4	$0.0	$32.1
Common	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$15.4	$0.0	$0.0	$15.4
Xcel General Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.4	$0.0	$0.0	$0.5
Total	$0.0	$0.0	$0.0	$0.0	**$0.0**	**$3.0**	**$2.2**	**$74.1**	**$0.4**	**$0.0**	**$79.8**

* Child Work Order - 11133705 - EPU Condensate Demin System Replacement

Q. WHY DID THE CONDENSATE DEMINERALIZER MODIFICATION COST MORE THAN ORIGINALLY ESTIMATED?

A. There were three primary factors that drove our costs for this modification. First, as discussed above, the scope of this project increased. Second, due to the space limitations and high radiological environment of the vessel vaults, our design efforts were substantially greater than anticipated. Finally, for these same reasons implementation costs increased. I will discuss each of these factors in detail below.

Scope Additions. As I previously discussed, the scope of this modification increased from replacement of five condensate demineralizer vessels and filter elements to a replacement of the condensate demineralizer system. The conceptual scope did not consider the condition of the rest of the system for long-term operation of the station. The final scope included replacement of the condensate piping, wiring, air surge systems, backwash system, and the control panel.

Design and Engineering. The design process for this modification was the most complex of the 2011 modifications. The design process spanned three years and required multiple iterations due to changes in project scope. The primary issues were the complexity of piping interferences, the condition of system wiring that was not discovered until substantial demolition was completed, and the discovery of the backwash receiving tank design issue that required expedited design changes in the months before the 2011 outage. When a pipe or support required relocation, structural analysis and further design was necessary to ensure we safely completed the modification. Shortly before the 2011 outage began we discovered that the backwash tank was designed as an atmospheric tank and was insufficient to withstand overpressure of the backwash process. Use of an atmospheric tank in this system would have presented significant risk of system failure, resulting in sudden release of contaminated water and resin from the backwash receiving tank. We proceeded with parallel processes in the months before the 2011 outage to simultaneously progress the constructability and re-design of this modification.

Installation. We incurred $32.1 million in installation costs primarily due to space and radiological limitations involved in installing the vessels in the condensate vaults and the discovery of plumbing and construction interferences during the 2011 outage. The condensate demineralizer vessels process reactor water and are highly radiological and are, therefore, contained in concrete vaults approximately eight feet square in size. These vaults, severely limit access to the condensate vessels. When the station was originally constructed, the vaults were poured after the vessels, wiring, and piping were installed. Because of the space limitations imposed by the preexisting vaults, we had to install the vessels and we spent thousands of hours installing the vessel auxiliaries during the 2011 outage. Moreover, due to these spatial limitations, only two people could work in a vault at one time, and due to the radiological work environment, laborers were required to comply with work permit restriction, personal protective equipment, and step off protocols. Both of these factors contributed to our installation costs for this modification.

Q. COULD THE COMPANY HAVE TAKEN ACTION TO AVOID THESE DESIGN OR INSTALLATION ISSUES?

A. No. Because the condensate demineralizer vessels are not accessible during operations, we were required to complete our pre-installation evaluation during prior outages. We relied on as-built drawings to develop the detailed design as we did not develop detailed designs by our 2009 outage. This was one of the risks we accepted as a result of accelerating certain work under our parallel path process. Once implementation began, however, we found that the piping configuration of the condensate demineralizer system did not entirely match the as-built drawings.

Q. WHAT MEASURES WERE IMPLEMENTED TO MITIGATE COST INCREASES RELATED TO THESE CHALLENGES?

A. We identified design issues with the initial designers and requested revisions to address these concerns, and when necessary, we engaged another designer to complete the design work necessary for the modification. We also implemented a revised testing protocol that allowed us to test complete vessels while other vessels were being installed. As a result, we shortened the overall testing schedule by approximately 10 days and substantially reduced impacts to the outage schedule.

Q. WHAT ALTERNATIVES DID THE COMPANY CONSIDER TO MITIGATE THE DELAY ON THE CONDENSATE DESIGN?

A. The nature of a parallel path of design and construction results in the need to adjust more frequently to changed conditions than under a more linear construction sequence. As we approached the 2011 outage, we evaluated whether or not to delay certain modifications given the progress of the modification designs. We determined that we should delay installation of two feedwater heaters. We decided, however, to proceed with replacement of the condensate demineralizer system. The costs for design and implementation in-outage were somewhat higher as the implementation team needed to work closely with the design team to identify interferences and efficiently create solutions around them.

In my opinion, the condensate demineralizer system was in need of replacement for 2011 to continue safe operations of the station. Typically, resin can be expected to sufficiently perform for approximately two years. By 2010, the vessels and filter elements supported the resin for only six months before needing to be recharged. Further, the existing analog control system was challenging from an operational perspective, and we identified water quality issues with the potential to lower Monticello's availability. We had delayed certain work to the third implementation outage (which turned out to be the 2013 outage), and the deferral of the condensate demineralizer system replacement to that outage scope would have further lengthened an already substantial outage. In light of these factors, I continue to believe that the parallel pursuit of the design and construction of the condensate demineralizer during the 2011 outage was the preferable alternative.

Q. DID THE CONDENSATE DEMINERALIZER SYSTEM REPLACEMENT DIRECTLY AFFECT THE LENGTH OF THE 2011 OUTAGE?

A. The construction of the condensate demineralizer extended the outage by ten days. Most of our contractors were not required to complete this modification, and we released them during this extension. Our daily labor rate during this ten-day period was in the range of $100,000 to $150,000. The 10-day delay, therefore, resulted in an additional modification cost of approximately $1.0 to $1.5 million.

Q. DO YOU THINK PARALLEL DESIGN AND CONSTRUCTION WAS THE PRIMARY REASON FOR THE INCREASED DESIGN AND IMPLEMENTATION COSTS OF THIS MODIFICATION?

A. No. Our primary issue with respect to implementation was labor productivity as a result of the space limitations and radiological conditions of the vaults as discussed above. The additional costs associated with labor productivity as a result of these conditions could have been better anticipated but could not have been avoided. The increased design costs were associated with the need to replace a complex system that took several years to design and the need to incorporate the larger scope of work.

Q. HOW DID THE CONDENSATE DEMINERALIZER MODIFICATION IMPROVED OPERATIONS AT MONTICELLO?

A. The new system efficiently removes fine debris and resin from the condensate, and as a result we expect reduced operation and maintenance costs. The replacement of our analog control system with automated, digital controls reduces our reliance on individual operators to consistently run the condensate system and has made the plant safer and more reliable.

E. Major Modifications – Transformer Replacements

Q. PLEASE PROVIDE AN OVERVIEW OF THE TRANSFORMER REPLACEMENT MODIFICATION.

A. The transformer replacement project was installed during the 2009 (1AR) and 2011 (main power transformer) outages at a total cost of approximately $30 million (Work Order Nos. 10943007 and 10735617). This modification included replacement of the 1AR emergency transformer and the main power transformer, and other necessary associated system work.

A detailed summary of the scope of the transformer replacement modification and photos of the installation can be found in Exhibit ___ (TJO-1), Schedule 24.

Q. WHAT IS THE FUNCTION OF THE 1AR EMERGENCY TRANSFORMER AND MAIN POWER TRANSFORMER AT MONTICELLO?

A. The 1AR emergency transformer supplies electricity to the station from the external transmission system to support the electrical needs of Monticello. The incoming voltage is adjusted through this transformer to meet plant equipment needs.

The main power transformer distributes electricity generated at the station to the external transmission system. The outgoing voltage is adjusted through this transformer to align with the external 345 kV transmission system.

Q. WHAT WAS THE INITIAL ESTIMATE FOR THE MAIN TRANSFORMER REPLACEMENT MODIFICATION?

A. The replacement of the main power transformer and the 1AR emergency transformer were estimated to cost approximately $16.9 million (2008$). The estimate only included the replacement of these two components and not other associated work.

Q. WAS THERE A CHANGE IN THE SCOPE FOR THIS MODIFICATION?

A. The scope changed slightly. Instead of disposing of the main power transformer, we decided to refurbish it and store it onsite as a spare transformer for our station. This refurbished main power transformer stored onsite provides the station with a transformer ready for expedient deployment in the event our new main power transformer experiences operational issues. The refurbishment of the main power transformer allowed us to avoid the acquisition of a new spare main power transformer as recommended under best practices. As part of the modification, we also prepared the main power transformer for movement onsite after delivery, installed main power transformer fire detection and suppression systems to meet insurance requirements, reconciled electrical relay operations between the new transformer and the station electrical system, and reconfigured the isophase bus duct cooling.

Q. WHY DID THE MAIN POWER TRANSFORMER REQUIRE REPLACEMENT?

A. The existing main power transformer was approximately 40 years old. Our experience with large transformers at our generating facilities suggests that this transformer was near the end of its useful life. If a main power transformer fails, the plant remains offline until we can replace or repair it, which can take a prolonged period of time. The main power transformer was identified in 2006 as due for replacement due to its aged condition.

Q. WHY DID THE 1AR EMERGENCY TRANSFORMER REQUIRE REPLACEMENT?

A. The 1AR transformer also required replacement due to its age. We acquired the 1AR transformer from another facility when it was approximately 30 years old, and it was approximately 60 years old at the time it was replaced. This transformer was one of the oldest transformers still in service in the United States nuclear fleet.

Q. WHAT WAS THE ACTUAL SPENDING ON THE TRANSFORMER REPLACEMENT MODIFICATION?

A. We incurred approximately $29.9 million to complete this modification. Table 19 provides our cost for the transformer replacement modification project by major cost category.

Table 19. Transformer Replacement Modification Cost by Category (Million $)

Main Transformer	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1
Design/Engineering	$0.0	$0.0	$0.0	$0.0	$0.8	$1.7	$0.3	$1.4	$0.0	$0.0	$4.3
Materials/Components	$0.0	$0.0	$0.0	($0.0)	$0.0	$9.3	$2.6	$0.2	$0.0	$0.0	$12.1
Installation	$0.0	$0.0	$0.0	$0.0	$0.0	$1.3	$0.5	$2.7	$0.0	$0.0	$4.5
Common	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$8.6	$0.0	$0.0	$8.6
Xcel General Costs	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	$0.1	($0.0)	$0.0	$0.3
Total	**$0.0**	**$0.0**	**$0.1**	**($0.0)**	**$0.8**	**$12.4**	**$3.4**	**$13.1**	**$0.0**	**$0.0**	**$29.9**

* Child Work Orders - 10943007 - MNGP EPU Main Power Transformer, 10735617 - MNGP EPU-1AR Transformer Replacement

Q. WHY DID THE FINAL COSTS FOR THE TRANSFORMER REPLACEMENT MODIFICATION EXCEED THE INITIAL ESTIMATE?

A. The main reason we incurred costs in excess of our initial estimate was because the initial estimate was not inclusive of all of the installation work necessary to complete this modification, including the main power transformer relay synching, the installation of fire protection equipment, and the installation of the isophase bus duct cooling. We also incurred additional costs to refurbish the existing main power transformer and construct on-site storage. Finally, there were escalation costs associated with the equipment doe to commodity price changes between the time of the initial estimate and procurement.

Q. DID THE COMPANY EXPERIENCE ANY CHALLENGES WITH THIS TURBINE MODIFICATION?

A. We experienced vendor challenges with the fabrication and delivery of the main power transformer, but we incurred no additional costs as a result of these vendor issues. We originally intended to replace the main power transformer in 2009 but due to vendor manufacturing issues, we deferred this work to the 2011 outage. The vendor also damaged the transformer during delivery to Monticello. The vendor remedied these issues at its expense and we incurred no additional costs to overcome these challenges.

Q. HOW HAS THE TRANSFORMER REPLACEMENT MODIFICATION IMPROVED OPERATION AT MONTICELLO?

A. The new transformers replaced 40-year-old and 60-year-old transformers. In their existing conditions prior to replacement, the transformers would not meet current standards for the station life and posed reliability risks for Monticello's continued operation. We believe that the replacement of these transformers was an important modification to undertake for the life extension of the station.

F. Major Modifications – Feedwater Heaters

Q. PLEASE DESCRIBE THE FEEDWATER HEATER MODIFICATION.

A. Portions of the feedwater heater modification[5] occurred during the 2009, 2011, and 2013 outages. The total cost for all work associated with this modification was approximately $115 million. A summary of the scope of the feedwater heater modification and photos of the arrival and initial line-up of the 15 A feedwater heaters are provided in Exhibit ___ (TJO-1), Schedule 25.

Q. WHAT ARE THE FEEDWATER HEATERS, AND WHAT PURPOSE DO THEY SERVE IN THE PLANT?

A. The feedwater heaters are designed to increase the water temperature prior to it entering the reactor pressure vessel to improve the thermodynamic efficiency of the system.

The other equipment included in the feedwater modification, the CARVs, moisture separator drain tank ("MSDT"), thermowell, drains and dumps, and main steam line navy nipples, all perform essential functions along the main steam lines of the turbine generators.

Q. WHAT WAS THE INITIAL SCOPE AND COST ESTIMATE FOR THE FEEDWATER HEATER MODIFICATION?

A. The feedwater heater modification was estimated to cost $37.0 million (2008$). The estimate included rerating six feedwater heaters (12, 14, and 15 A/B heaters), replacing drain and dump valves, replacing only the CARVs

[5] Work Order Nos. 1113719, 11133713, 11284286, 11286961, 11638897, 11757884, 11842626, 11286981, 11376086, 11133856, and 11376103.

(not the associated piping), rerating drain coolers, testing main steam navy nipples, and making modifications to the MSDT.

Q. HOW DID THE SCOPE OF THIS WORK CHANGE DURING DESIGN OF THE FEEDWATER HEATER MODIFICATION?

A. The scope of work for the feedwater heater modification changed substantially during the design of the LCM/EPU Program. Several changes were made to the feedwater heater modification scope for feedwater heaters, drain and dump piping, the turbine floor, main steam thermowell, and CARVs. The most notable scope additions are:

<u>Replace 13 A/B, 14 A/B, and 15 A/B Feedwater Heaters</u>: We initially intended to rerate the feedwater heaters, but decided during the design phase that replacement was required. The 14 A/B and 15 A/B heaters were original equipment and we could no longer continue to modify and repair the shell and tube heat exchangers. The condition of the 13 A/B feedwater heaters during inspections in 2007 indicated that replacement was necessary. We determined that we could rerate the 11 and 12 feedwater heaters for EPU conditions.

<u>Turbine Floor 951'</u>: The decision to replace the 14 A/B and 15 A/B feedwater heaters with larger heaters required structural analysis and reinforcement of the turbine floor at a cost of approximately $6 million. This was a substantial undertaking from a design and installation perspective.

<u>Replace Drain and Dump Piping</u>: We decided to replace approximately 400 feet of piping with larger piping and remove associated asbestos insulation, to accommodate the extended life of the station. This piping replacement likely

could have been delayed to another outage, but because substantial feedwater heater work was underway, but it was most cost-effective to undertake the replacement concurrent with the other work.

Q. WHAT WAS THE ACTUAL SPENDING ON THE FEEDWATER HEATER MODIFICATION?

A. We incurred approximately $114.9 million to complete this modification. Table 20 provides our cost for the feedwater heater modification by major cost category.

Table 20. Feedwater Heater Cost by Category (Million $)

Feedwater Heater	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Design/Engineering	$0.0	$0.0	$0.0	$0.0	$0.1	$2.4	$1.8	$19.7	$0.5	$1.6	$26.1
Materials/Components	$0.0	$0.0	$0.0	$0.0	$0.0	$1.1	-$4.3	$3.9	$1.5	$0.8	$3.0
Installation	$0.0	$0.0	$0.0	$0.0	$0.0	$8.9	$0.7	$24.5	$1.9	$23.5	$59.5
Common	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$12.0	$9.4	$4.4	$25.8
Xcel General Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.4	$0.0	$0.1	$0.5
Total	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.1**	**$12.4**	**-$1.7**	**$60.5**	**$13.2**	**$30.4**	**$114.9**

* Child Work Order - 11638897 - MNGP EPU 13 A&B Feed Wtr Heater, 11842626 - EPU 13 A & 13B Feed Water Heater Repair, 11133719 - EPU FW Heater Drain & Dump Valve, 11284286 - MNGP EPU Rpl 4 FW Drain & Dump, 11757884 - MNGP Replc 14/15 FW, 11286961 - MNGP EPU Rpl 14&15 A/B FW Heater, 11133856 - EPU FW Flow Transmitters/PC In, 11133713 - EPU CARV Replacement, 11286981 - Moisture Separator Drain Tank, 11376086 - Drain Coolers, 11376103 - Turbine Floor 951'

Q. WHY DID THE FINAL COSTS OF THE FEEDWATER HEATER MODIFICATION EXCEED THE INITIAL COST ESTIMATES?

A. There were three primary cost drivers for the feedwater heater modification: 1) replacement of 400 feet of drain and dump piping instead of analysis only; 2) replacement of the CARVs with larger valves and of associated piping with larger diameter piping; 3) replacement of the six feedwter heaters.

<u>Drain and Dump Piping</u>: Initially, we anticipated further analysis of the drain and dump piping and possible rerating. Upon further inspection, we determined that the piping would require replacement during the course of the continued station operation. In light of the other work we were performing on the systems that the piping supports, the decision was made to replace the

drain and dump piping during the 2009 and 2011 outages. This decision required substantial design and installation efforts. Replacement of the piping was completed at a cost of approximately $30 million. We relied primarily on as-builts for design of the piping but, once we got into the 2009 outage, were required to make several in-outage design modifications because of in-plant conditions.

<u>CARV and Piping</u>: Our initial scope contemplated replacement of the valves only. Further analysis identified that larger valves and piping would be necessary to support the continued operation of the station.

<u>Replacement of Feedwater Heaters</u>: The equipment costs for replacement of the heaters was approximately five times the costs associated with analysis of equipment for the initially-anticipated rerating. 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.

Q. COULD DESIGN AND INSTALLATION COSTS HAVE BEEN REDUCED THROUGH BETTER PLANNING IN ADVANCE OF THE OUTAGES?

A. I do not believe so. While we could have anticipated the cost of the design and installation work better, it could not have been avoided. The sub-modifications we undertook as part of the feedwater heater modification were all related to equipment in the station that required replacement to support the continued operation of the station. The size of some equipment (like the feedwater heaters) was increased to support EPU conditions, but the equipment would require replacement even absent EPU. Given the scope of work we were required to undertake because of short-term equipment condition needs, it was most cost-effective to expand the scope of work for this modification and take advantage of concurrent design and installation activities.

Q. DID THE FEEDWATER HEATER MODIFICATION PROVIDED ADDED BENEFITS TO THE PLANT?

A. Yes. The feedwater heater project is installed and operational at Monticello. Four of the six feedwater heaters that were replaced had been significantly repaired since they were installed at the time the plant was constructed in 1970. We anticipate operation and maintenance costs for this equipment to be reduced because of the replacement. As I mentioned earlier, four of these six heaters were original plant equipment and we had successfully maintained operation of this equipment beyond the estimated equipment life. The CARVs are installed and provide over pressure protection to the turbine by providing an alternate path for the steam to the condenser should the turbine not be able to accept the steam. Feedwater heater drain and vent valves are installed and functioning to help maintain water level in the feedwater heaters. The new feedwater flow transmitters and pressure control instrumentation are installed and being used to measure feedwater flow in support of plant operation at the currently authorized power level. The feedwater system, with the new feedwater heaters, is necessary for the plant to operate at the currently authorized power levels. The new feedwater heaters are installed and are using steam extracted from the main steam flow to pre-heat water before it goes into the reactor to be boiled to steam. The new feedwater heaters are raising condensate temperature above the hotwell temperature in order to provide feedwater to the reactor to maintain a constant reactor water level in support of plant operation.

G. Major Modifications – Electrical Distribution Modifications

Q. WERE THERE ANY MODIFICATIONS THAT, ALTHOUGH CONSIDERED OPERATIONALLY INDEPENDENT, WERE INTERRELATED?

A. Yes. The reactor feed pumps and motors and the condensate pumps and motors modifications were both highly-depended on the electrical distribution system modifications selected for the station. The decision to forego the initially-proposed supplemental reactor feed pump and motor for replacement of the reactor feed pumps and motors along with the decision to forego modifications of condensate pumps and motors for whole replacement had an effect on how the electrical distribution system for the station would be designed.

Q. COULD THE REPLACEMENT PUMPS AND MOTORS FOR BOTH THE REACTOR FEED AND CONDENSATE SYSTEMS BE REPLACED BEFORE THE ELECTRICAL DISTRIBUTION SYSTEM WORK WAS INSTALLED?

A. While the work could occur concurrently, the implementation of the pumps and motors could not be completed until the 13.8 kV electrical distribution system was completed. I discuss the relationships between the reactor feed pumps and motors modification, condensate pumps and motors modification, and the 13.8 kV electrical distribution system modification below.

1. Major Modifications – Reactor Feed Pumps and Motors

Q. WHAT WAS THE REACTOR FEED PUMPS AND MOTORS MODIFICATION PROJECT?

A. The reactor feed pumps and motors project occurred during the 2013 outage at a cost of approximately $92 million (Work Order No. 11286955). The reactor feed pumps and motors modification included the replacement of two reactor feed pumps and two motors, replacement and relocation of auxiliary piping, and replacement of regulating valves and controls.

A summary of the reactor feed pumps and motors modification can be found in Exhibit ___ (TJO-1), Schedule 26.

Q. WHAT IS THE FUNCTION OF THE REACTOR FEED PUMP SYSTEM AT MONTICELLO?

A. The two reactor feed pumps are large pumps designed to move treated water (feedwater) into the reactor. The feedwater provides cooling for the reactor and is converted to steam to drive the high- and low-pressure turbines. Each pump is powered by an approximately 8,000 horsepower motor that is connected to the station's new 13.8 kV electric distribution system.

Q. WHAT WAS THE INITIAL ESTIMATE FOR THE REACTOR FEED PUMPS AND MOTORS MODIFICATION?

A. As noted above, in 2006, we investigated adding a supplemental reactor feed pump to Monticello. The addition of a supplemental feed pump was estimated to cost $27.8 million (2008$). This estimate focused on obtaining the EPU capacity requirements and did not include LCM costs that would have been incurred with replacement of the two existing pumps and motors during the 20-year license extension period.

Q. DID THE SCOPE OF THE REACTOR FEED PUMPS AND MOTORS MODIFICATION CHANGE SUBSTANTIALLY?

A. Yes, it did. At existing conditions, we were operating the reactor feed pumps and motors within the upper capacity limits. We evaluated the recommendation to add a smaller capacity supplemental reactor feed pump and motor. We also determined that even if we added a supplemental reactor feed pump, the two existing pumps and motors would require replacement in the near future. We determined that the third pump design was not workable due to size limitations and operating procedures. The pumps were original legacy equipment had repair issues and we were encountering difficulty locating spare parts. We elected to replace our existing pumps and motors with larger capacity equipment. This facilitated the uprate without the additional complications associated with the original three-pump design.

The decision to replace the existing pumps and motors with larger capacity equipment required that we reevaluate our initial plan to augment the station's existing 4 kV electric distribution system. The identified motors would have caused an extraordinary draw on a 4 kV system on startup. We determined that the draw on this system would not be acceptable within station safety margins. Additionally, we were required to replace or relocate significant amounts of piping to accommodate the new, larger pumps and motors.

Q. WHAT WAS THE FINAL COST OF THE REACTOR FEED PUMPS AND MOTORS MODIFICATION?

A. The final cost for the feed pump and motor modification was approximately \$92 million. Table 21 provides our cost for the modification by category.

Table 21. Reactor Feed Pumps and Motors Modification Cost by Category (Million $)

Reactor Feed Pumps	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Design/Engineering	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$4.1	$12.7	$3.4	$4.9	$25.2
Materials/Components	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.4	$0.7	$0.6	$2.0	$3.7
Installation	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.0	$8.1	$8.2	$36.8	$54.2
Common	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$8.6	$8.6
Xcel General Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2	$0.0	$0.0	$0.4
Total	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.1**	**$5.7**	**$21.8**	**$12.3**	**$52.3**	**$92.2**

* Child Work Order 11286955 MNGP EPU Replacement FW Pump

Q. WHY DID THE FINAL COST OF THE REACTOR FEED PUMPS AND MOTORS MODIFICATION EXCEED THE INITIAL ESTIMATE?

A. The primary cost increases for this modification resulted from the change in scope from a supplemental reactor feed pump and motor to the replacement of the two reactor feed pumps and motors. Not only did the cost increase due to the need to procure major equipment, but design and installation costs increased because of this decision. 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. We reduced the total modification time through our concurrent installation activities on the pumps and motors. The costs for the reactor feed pumps and motors modification would have either been incurred during the 2013 outage or at some time in the near future when the pumps and motors would have required replacement for operational issues.

Q. WHAT OTHER FACTORS CONTRIBUTED TO THE OVERALL COSTS OF THIS MODIFICATION?

A. We encountered delays in procurement because we had difficulty finding motors that would meet specifications. Also, 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. Last, 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 walkdowns.

Q. HAS THIS MODIFICATION PROVIDED ADDED BENEFITS AT MONTICELLO?

A. Yes. The replacement of the reactor feed pumps and motors allowed the plant configuration and operations to remain consistent during the extended life. This decision has saved countless hours of procedure revisions and operational training. Reliability has improved by addressing and eliminating wear conditions that necessitated preventative and corrective maintenance of this equipment.

2. Major Modifications – Condensate Pumps and Motors

Q. WHAT WAS THE CONDENSATE PUMPS AND MOTORS MODIFICATION PROJECT?

A. The condensate pumps and motors modification project occurred during the 2013 outage at a cost of approximately $21.9 million (Work Order Nos. 10943052 and 11845189). The project included the replacement of two condensate pumps and two motors, replacement of condensate pump and motor auxiliaries, modification of area cooling for the condensate pump motors, an increase in the condenser hotwell level, and completion of the required testing protocol.

A summary of the scope of the condensate pumps and motors modification can be found in Exhibit ___ (TJO-1), Schedule 27.

Q. WHAT ARE THE CONDENSATE PUMPS AND MOTORS AND HOW ARE THEY IN USE AT MONTICELLO?

A. The condensate pumps and motors move water from the hotwell of the condenser to the reactor feed pumps. The reactor feed pumps then supply water to the reactor where it is heated to produce steam. The steam is then fed to the high- and low-pressure turbines.

Q. WHAT WAS THE INITIAL SCOPE AND COST ESTIMATE FOR THE CONDENSATE PUMPS AND MOTORS REPLACEMENT MODIFICATION?

A. The original scope of this modification included the addition of a new impeller stage in the existing condensate pumps at a cost of approximately $3.2 million (2008$).

Q. DID THE SCOPE OF THIS MODIFICATION CHANGE SUBSTANTIALLY?

A. Yes, it did. Instead of adding a new impeller stage to the existing condensate pumps, the pumps and motors were replaced with larger capacity equipment. New piping and valves were also installed.

Q. WHY WAS THE CONDENSATE PUMPS AND MOTORS MODIFICATION REQUIRED FOR THE LCM/EPU PROGRAM?

A. We needed to replace these pumps and motors to meet the demand of the larger reactor feed pumps. To meet increased demand for water to the reactor feed pumps the condensate pumps needed to be replaced with different models to satisfy the increased flow requirements of the suction side of the reactor feed pumps and to provide distribution to the vessels. Even if we had not needed to replace these pumps and motors to meet the demand of the reactor feed pumps, the existing condensate pump internals would have been required to support continued operation.

Q. WHAT WAS THE FINAL COST OF THE CONDENSATE PUMPS AND MOTORS REPLACEMENT MODIFICATION?

A. We incurred approximately $21.9 million to complete this modification. Table 22 provides the cost for this modification by major cost category.

Table 22. Condensate Pumps and Motors Modification Cost by Category (Million $)

Condensate Pumps	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Design/Engineering	$0.0	$0.0	$0.0	$0.0	$0.0	$0.3	$0.8	$2.2	$0.6	$1.8	$5.7
Materials/Components	$0.0	$0.0	$0.0	$0.0	$0.0	$0.5	$1.6	$0.0	$0.1	$0.6	$2.9
Installation	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	$1.1	$1.7	$8.1	$11.1
Common	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2.0	$2.0
Xcel General Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.1
Total	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.8**	**$2.7**	**$3.4**	**$2.4**	**$12.6**	**$21.9**

* Child Work Orders - 10943052 - MNGP EPU Condensate Impeller/P, 11845189 - MNGP EPU Condensate Impeller R

Q. WHY DID THE FINAL COSTS FOR THE CONDENSATE PUMPS AND MOTORS MODIFICATION EXCEED THE INITIAL ESTIMATE.

A. The primary driver for the final cost relates to the decision to replace the condensate pumps and motors rather than add an impeller stage to the existing equipment. This replacement was not included in the original cost estimate and increased the equipment, design, and installation costs for this modification over the initial estimate.

We also experienced vendor fabrication issues with the condensate pumps and motors. Our vendors experienced difficulties fabricating equipment that met our design specifications. To meet these specifications, we required the vendor to modify the motors, which increased the heat load of the motors. This required further analysis of the area cooling systems. The additional analysis and resulting duct design and installation for area cooling added approximately $2 million to the modification. Additional fabrication issues delayed the shipment of necessary components from the estimated delivery dates. Many of the fabrication issues were addressed by our vendors at their cost. We incurred additional oversight costs and the delays affected our pre-outage planning protocol. However, these delays did not increase costs. This installation was not on the critical path and did not cause us to undertake material additional work.

Finally, the costs to install this modification were higher than anticipated. We attribute the higher installation costs to the in-outage designs required to address piping and wiring interferences encountered during the installation and the overall implementation productivity issues we encountered during the 2013 outage.

Q. WHAT MEASURES WERE IMPLEMENTED TO MITIGATE COST INCREASES RELATED TO THESE CHALLENGES?

A. When installation issues prevented full use of the assigned labor for the modification, we assigned work crews to other tasks without any schedule or budgetary impact. While we could have anticipated our costs better prior to undertaking this modification, the costs incurred could not have been avoided.

Q. HAS THIS MODIFICATION PROVIDED ADDED BENEFITS TO MONTICELLO?

A. Yes. The new condensate pumps efficiently and effectively accommodate higher flows and the water quality demands for the life extension of the plant as well as support operations at uprate conditions.

3. Major Modifications – 13.8 kV

Q. PLEASE PROVIDE AN OVERVIEW OF THE 13.8 KV ELECTRICAL DISTRIBUTION SYSTEM MODIFICATION PROJECT.

A. The 13.8 kV modification added additional buses at 13.8 kV voltage level to supplement our existing lower voltage (4 kV) electrical distribution system in the plant. The installation of the 13.8 kV Project (Work Order No. 11257804) occurred during the 2011 and 2013 outages at a total cost of approximately $119.5 million. This was the most expensive modification we undertook, and it was one of the most difficult modifications to complete because we are required to maintain electric service to ensure cooling of the fuel at all times during the installation of the new system. As a result, we had to stage the installation to ensure that certain power sources were available at the appropriate times. A summary of the 13.8 kV modification and photos of installation can be found in Exhibit ___ (TJO-1), Schedule 28.

Q. PLEASE DESCRIBE THE 13.8 KV ELECTRICAL DISTRIBUTION SYSTEM AT MONTICELLO?

A. The electrical distribution system at Monticello is comprised of feeders, breakers, protective relaying, controls, and instrumentation necessary to support the supply of power to many of the critical pumps in the plant including the feedwater pumps, the condensate pumps, and the reactor recirculation motors. This electrical system connects these components to the plants electrical buses and permits those pumps to operate as designed.

Q. Please explain why the 13.8 kV modification was necessary for the LCM/EPU Program.

A. In 2007, we decided to replace the reactor feed pumps and motors with larger capacity equipment to meet the operational and uprate needs of Monticello. In September 2007, we convened an "Electrical Summit" to evaluate the options for accommodating the replacement reactor feed pumps and other new equipment. We evaluated two primary electrical options for feasibility, cost, and schedule impact. The first option involved modifications to our 4 kV system to support both the safety- and non-safety-related equipment at Monticello. The second option involved replacement of the 1R and 2R transformers to supply new 13.8 kV busses to feed the reactor feed pump, condensate pumps, and recirculation MG set motors. The 4 kV system would continue to support our other equipment at Monticello including critical safety equipment such as the on-site station blackout generations.

Q. Why did the Company pursue 13.8 kV as a solution?

A. Our analysis indicated that the incremental additional cost associated with the 13.8 kV system was less than one percent over the new 4 kV bus alternatives. Further, installing a 13.8 kV system for our non-safety-related equipment would not only provide a desirable split in electric distribution supply but also increase the operating margin of our 4 kV system that would continue to support our safety-related equipment. We also took into account the fact that the 4 kV switchgear and breaker design were obsolete and no longer supported by the original manufacturer. So the alternative would have required replacement of, or in addition to, the 4 kV system, which would have ultimately been substantially the same project we installed. The voltage of the new distribution system (4 kV versus 13.8 kV) would not have materially affected the costs.

Q. WHAT WAS THE ORIGINAL ESTIMATE FOR THE 13.8 KV MODIFICATION?

A. We developed a conceptual scope and estimated the 13.8 kV modification at a cost of $20.9 million (2008$). This estimate did not include design and construction of the 13.8 kV switchgear room or the specific locations of raceways for power or control cables.

Q. DID THE SCOPE OF THE 13.8 KV MODIFICATION CHANGE OVER TIME?

A. Yes, it did. We determined through the design process that due to the size of the new equipment, we would need to locate the new bus work at a new location within the plant. This location had to be large enough to accommodate the new bus work; it also needed to be in a location that would provide for adequate cooling. Ultimately, we designed a space for the new 13.8 kV bus work that was in a separate room. This required approximately 14 miles of new cable and reaceway to run all the cables.

Had we chosen to construct new 4 kV bus work, however, we would have faced essentially the same set of issues. Either way, we would have had to split electrical loads and preserve margin to the safety-related system supported by the 4 kV busses and we would have had to add addition busses. We would have required a space in an area that provided adequate cooling for this equipment. Even at 4 kV, we would have been required to find a new location that would have required significant distance for pulling cable. This is a function of the very small footprint of Monticello.

Q. WHAT WAS THE FINAL COST OF THE 13.8 KV MODIFICATION?

A. We incurred approximately $119.5 million to complete this modification. Table 23 provides our cost for the 13.8 kV project by category.

Table 23. 13.8 kV Cost by Category (Million $)

13.8 kV Distribution	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	$0.2
Design/Engineering	$0.0	$0.0	$0.0	$0.0	$0.0	$3.2	$5.9	$5.9	$2.5	$6.4	$23.9
Materials/Components	$0.0	$0.0	$0.0	$0.0	$0.0	$0.5	$3.6	$3.5	$0.4	$2.5	$10.3
Installation	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$2.2	$10.0	$12.9	$48.1	$73.2
Common	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$11.2	$11.2
Xcel General Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.3	$0.2	$0.1	$0.1	$0.7
Total	$0.0	$0.0	$0.0	$0.0	$0.0	**$3.7**	**$12.0**	**$19.6**	**$15.8**	**$68.5**	**$119.5**

* Child Work Order - 11257804 - MNGP EPU 13.8kV Distribution

Q. WHY DID THE 13.8 KV MODIFICATION COST MORE THAN INITIAL ESTIMATES?

A. Primarily, the final cost of the modification exceeded the initial estimate because:

- The initial estimate was based on conceptual, rather than detailed, engineering;
- We were implementing a first-of-its-kind system in a nuclear facility;
- As noted above, the new cable needed to travel through this area and because this is an electrically-sensitive area, the design work required careful analysis through an iterative process to ensure safe installation; and
- The Company and its external design organizations encountered design challenges to route the conduit and raceways and design the switchgear room.

Among these reasons, the costs necessary to install the system was by the largest driver, and we incurred more than $73 million in installation costs.

Specifically, 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, for the 2013 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.

Q. HOW HAS THE 13.8 KV MODIFICATION IMPROVED OPERATION AT MONTICELLO?

A. All of the components of the 13.8 kV system are currently installed in the plant and operating. This system accommodates the increased electrical demands of the reactor feed pumps, condensate pumps, and associated equipment to achieve the increased output from the plant. In addition, by increasing margin at the plant, the new 13.8 kV system improves reliability and enhances the flexibility, simplicity, and safety of plant operations. Moreover, by replacing an aging system, the 13.8 kV modification avoided a future capital project to upgrade the plant's electrical distribution system and the probable escalation of costs.

Similar to the evaluation of the steam dryer replacement, which was initially thought of as EPU-related but later determined to be needed for the continued operations of the plant, the 13.8 kV system was conceived as an uprate solution. The margin and obsolescence improvements of the 13.8 kV system, however, make it much more related to LCM.

Q. PLEASE ELABORATE ON HOW THE 13.8 KV SYSTEM IS RELATED TO LCM.

A. The 13.8 kV system provided significant improvement in electrical system operating margin over the former 1960s plant design and equipment. Before the Project the plant operated with a 4 kV system, which allowed minimal margin to prevent overloading the electrical buses. Any increased loads on the system would make the plant more vulnerable to plant transients. The existing system already strained its original margin due to increased loads through led to low voltage situations during major power draws. There was little margin left for additional loads. With the new 13.8 kV system, the plant has significant additional electrical margin on these buses and faces less risk of trips and forced outages. As such, the 13.8 kV system improved plant reliability. This is especially beneficial post-Fukushima given the heightened safety focus on power reliability to plants and the safety significance of a loss of power.

While complex, it was safer to install the 13.8 kV system rather than modify or replace the 4 kV system on a piecemeal basis. The 4 kV system was not designed to be taken out of service at any time because it must operate continuously. If we had to modify or replace the 4 kV system, it would require a redundant system (*i.e.*, separate busses) first to ensure continuity of service while constructing the new system. Such a course would have been just as costly. An added benefit of the 13.8 kV system provided increased operating margins, portions of the 13.8 kV system – rather than the entire 4 kV system – can be taken out of service as plant conditions warrant. This improves the plant's operating flexibility.

While uprate concerns triggered the look at larger reactor feed pumps and subsequently new electric loads, as it turned out, the new configuration was going to be needed due to additional loads already being required as a result of Fukushima and more that are reasonably anticipated. In today's world, it would not have been wise to continue with existing electric margin even in the absence of the power uprate.

H. Major Modification – Licensing Costs

Q. WHAT COSTS DID THE COMPANY INCUR IN SEEKING LICENSE AMENDMENTS FOR THE EPU?

A. Our licensing costs through August 31, 2013, are approximately $59.3 million and we expect another approximately $5 million to prepare for ascension once the EPU is granted. This final cost compares with an initial estimate for licensing costs of about $28.6 million. In 2011, when the Program was reorganized the estimate was increased to reflect increases in cost associated with the strain gages and accelerometers associated with the steam dryer and multiple revisions of the steam dryer analysis that were required by the NRC reviewers.

Q. WHAT ARE THE FACTORS THAT CAUSED THE LICENSING PROCESS TO EXCEED THE ORIGINAL ESTIMATE?

A. The following factors contributed to our final licensing costs: a) our initial estimate was too low; b) increased NRC scrutiny over calculations, including the effort around the CAP-credit issue; c) initial application and replacement steam dryer; and d) replacement steam dryer review. All of these issues had the effect of increasing the cost and schedule of the licensing effort.

Q. WHAT DO YOU MEAN WHEN YOU SAY THAT THE INITIAL ESTIMATE OF LICENSING COSTS WAS TOO LOW?

A. Our initial estimate $28.6 million was based on our prior experience with the 1998 uprate project and General Electric's prior experience. We assumed that about half of these costs would be incurred through General Electric and roughly half would be internal and other contractor costs. We understood we would have additional internal costs and that we would incur substantial costs in preparing the initial license amendment application. As the Project progressed, however, the need to incorporate General Electric's work into the license amendment request and complete additional calculations to respond to the NRC's requests for additional information consumed more engineering and licensing hours than originally anticipated.

Q. PLEASE DESCRIBE THE CATEGORY OF ADDITIONAL NRC SCRUTINY OVER CALCULATIONS.

A. Key elements of the increase included an increased focus on the calculations required to support our amendment request. The number of calculations required increased dramatically in the time period from the uprate project in 1998. Changing NRC requirements associated with calculation quality substantially increased work requirements for calculation revisions as the project progressed. This resulted in the need for the Company to perform a complete reconstitution of many programs. In addition, substantial changes were required related to instrument set-point methodology.

In addition, the CAP credit issue, described in the Licensing section of this testimony, resulted in the need for significant analytical work. It would be difficult to capture all of the costs associated with this effort. The NRC put the whole license process on hold for 18 months while it underwent an internal analysis to develop a consensus position on how the CAP issue should be treated. We spent numerous months working with the boiling water reactor owners' group, consultants and legal counsel to resolve confidentiality concerns as part of a group study working through information requests and analyses to develop an analysis that would satisfy the new requirements.

We estimate the cost of work associated with just the additional required calculations and instrument set-points methodology to be about $7.5 million, including CAP.

Q. WHAT LICENSING COSTS DID YOU INCUR REGARDING THE STEAM DRYER?

A. There are two separate issues here. First, there are costs associated with refiling the application with the new steam dryer. Second there are costs associated with the NRC review of the new steam dryer.

With regard to the need to refile our license amendment request, I estimate that it cost about $4.5 million. These costs are for new steam dryer analyses that and revisions to the EPU License amendment request to accommodate the new analyses.

With regard to the structural analysis of the new steam dryer, the protracted NRC review caused significant additional licensing costs that have continued through the process. We made repairs to strain gauges used to monitor steam dryer loads and accelerometers used to monitor piping vibration for inaccessible piping that resulted in costs of over $1 million. Removal of steam dryer instrumentation to allow refueling activities to progress included a cost of roughly $1 million.

Finally, review of the specifications for the new steam dryer resulted in significant additional analysis. The NRC asked the Company to provide six separate analyses of the steam dryer. Each one of these analyses required considerable effort by internal and external resources.

Q. HAS THE NRC'S INCREASED FOCUS ON NATURAL DISASTERS IN THE AFTERMATH OF FUKUSHIMA IMPACTED XCEL ENERGY?

A. Yes. I believe we have already seen increased regulatory scrutiny during the pending license amendment process. While we were surprised by the heightened scrutiny at the outset, as we moved through the process, Fukushima appeared to be a major contributor in further increased scrutiny we experienced.

VIII. OTHER MODIFICATIONS

Q. DID YOU COMPLETE LCM/EPU PROJECT MODIFICATIONS IN ADDITION TO THE MAJOR MODIFICATIONS DISCUSSED ABOVE?

A. Yes, we did. Below is a list of the other modifications, the child work order associated with those modifications and our actual spending for each modification. In total these other modifications represented about five percent of our total spending.

Table 24. LCM/EPU Program Modifications Beyond Major Modifications

Modification Name (Work Order Number)	**Cost**
Reactor Water Cleanup Capacity Improvement (WO# 11286992)	$5.7 million
Certificate of Need (WO# 10884258)	$0 removed from project
General Electric ZIP installation (WO# 10943047)	$2.6 million
Expansion Joints (WO# 11132414)	$7.0 million
Isophase Bus Cooling Upgrade (WO# 11133861)	$5.4 million
EQ Transmitters & Detectors (WO# 11133865)	$0.8 million
MISV Solenoid Valve Replacement (WO# 11133871)	$0.3 million
Drywell Brick Removal in Bioshield (WO# 11133877)	$0.1 million
Drywell Spray Flow Valve Replacement (WO# 11133931)	$0.2 million
Off Gas Dilution Fan Cable (WO# 11194611)	$0.6 million
1 AR Cable Replacement (WO# 11213813)	$0.0 million, removed from LCM/EPU Program (now a plant project)

Modification Name (Work Order Number)	Cost
Generator Rewind (WO# 11286966)	$6.7 million
Exciter Replacement (WO# 11286973)	$0.1 million
Stator Water Cooler replacement (WO# 11286985)	$2.4 million
E&S for EPU (WO# 11398720)	-$375
PCT Vent & Purge Valve replacement (WO# 11410738)	$0.4 million
Steam Dryer Instrument Removal (WO# 11776513)	$1.2 million

Q. WHY HAVE YOU NOT PROVIDED DESCRIPTIONS OF EACH OF THESE MODIFICATIONS THAT ARE SIMILAR TO THOSE INCLUDED ABOVE?

A. In aggregate, these smaller modifications and licensing actions represent about five percent of the total cost of project. While we are providing detailed information regarding the cost and execution of each of these modifications, we felt it was appropriate to focus our discussion on the ten major modification groups that represented the majority of our project costs.

Q. DID YOU FOLLOW SIMILAR DESIGN, ENGINEERING, AND CONSTRUCTION PROCESSES FOR THE REMAINING MODIFICATIONS AS YOU DID FOR THE MAJOR MODIFICATIONS DISCUSSED EARLIER IN THIS SECTION OF YOUR TESTIMONY?

A. Yes, we did.

Q. DID YOU ENCOUNTER ANY DIFFICULTIES OR CHALLENGES ASSOCIATED WITH THE COMPLETION OF THESE OTHER MODIFICATIONS?

A. Yes, we did. The challenges we faced with these modifications are similar to the types of challenges and difficulties we confronted while completing the major modifications discussed earlier in this section of my testimony.

Q. ARE EACH OF THE OTHER MODIFICATIONS CURRENTLY IN-SERVICE AND PROVIDING BENEFITS TO THE PLANT AND XCEL'S CUSTOMERS?

A. Yes.

IX. PROGRAM BENEFITS

Q. PLEASE SUMMARIZE THE OUTCOMES YOU ACHIEVED.

A. Despite the costs, delays and all of the challenges we faced, we are pleased that our work will provide clean, reliable and cost-effective energy to our customers through 2030 and possibly beyond. The Monticello plant is safer and more reliable than it was prior to this effort, and we have restored additional margin to position ourselves well for operations into the future. While we do not have a license to operate beyond 2030, I know of no reason why the plant-side systems could not operate beyond 2030 with proper NRC and Commission approvals for continued operations.

Q. PLEASE SUMMARIZE THE BENEFITS TO CUSTOMERS FROM NUCLEAR GENERATION AT MONTICELLO.

A. Nuclear generation provides carbon-free baseload generation at low incremental fuel costs. Nuclear generation allows us to avoid millions of tons of CO_2 emissions annually and completely avoids any NO_X, SO_2, Mercury, or other smokestack pollutants associated with fossil-fuel generation. The fuel diversity provided by the nuclear component of our fleet provides an important hedge against volatile fossil-fuel prices. Xcel Energy's investments in Monticello will ensure that nuclear energy will continue to provide these benefits for at least two more decades.

Q. PLEASE SUMMARIZE THE BENEFITS TO EMPLOYEES AND THE PLANT FROM THE PROGRAM.

A. Further, we made design choices to ensure that the plant would be user-friendly to our NRC-licensed operators. We placed a premium on the human factor by trying to minimize the number of new procedures our operators need to learn. We tried to make the new systems compatible with our prior protocols for the benefit of our operators. In the end, the plant operators have the benefit of new systems that operates on the same basis as the prior systems.

- In addition, we obtained a number of valuable and tangible benefits.
- Our work substantially improves electrical performance in the plant and reduces the likelihood of trips and forced outages.
- We included systems that provide the plant with additional safety margin and in some instances restore margin that had been utilized during prior upgrades. This positions us well for future use as demand on the internal electrical system increases.
- Some of the new, larger pumps and motors we installed provide additional pumping capacity to safely operate the reactor at the current and uprated output levels.
- The replacement steam dryer is providing unexpected benefits because its performance and efficiency are exceeding our expectations which we

anticipate will directly lower the operating and maintenance costs of the plant for the remainder of its useful life.

- Along with some of the equipment installations we replaced degraded wiring and obsolete controls to support the extended operations of the plant.
- In addition to these direct benefits, we believe that the Plant will operate more reliably following the completion of this Program. Past experience in the industry suggests that reliability of the new components is expected to be relatively stable until the components near the end of their useful life. We anticipate that the replacement of components near the end of their useful lives will push out the uptick in failures and improve plant reliability during most of the remaining operating life of the plant.

A. Program Cost-Effectiveness

Q. OVERALL, IS THE LCM/EPU PROGRAM COST EFFECTIVE?

A. Yes. The Monticello plant as a whole is cost-effective under today's conditions, even with paying $665 million for all of the LCM/EPU improvements. Mr. Alders provides an extended discussion on the cost-effectiveness of continued generation from Monticello. As Mr. Alders describes, we reviewed several scenarios and determined that:

- Monticello generation would have been cost effective in 2008 even if we had known final Program costs would be $665 million.
- Montcello as a whole remains cost-effective in 2013.
- Annually, it was reasonable to continue forward with the Program in light of the costs that had already been incurred.
- Incrementally, the cost-effectiveness of the additional 71 MWs varies, depending on the allocation of costs attributable to the 71 MW.

B. LCM/EPU Cost Separation Analysis

Q. DID YOU PROVIDE ANY INFORMATION IN SUPPORT OF MR. ALDERS' ANALYSIS OF THE COST-EFFECTIVENESS OF THE EFFORT?

A. Yes. As part of this filing the Company decided to attempt to segregate the costs of the initiative between those costs that were unavoidable LCM work and those costs that constitute avoidable EPU work.

Q. DID THE COMPANY SEPARATELY TRACK DISCRETE LCM-ONLY AND EPU-ONLY COSTS?

A. No. We managed the Program as a unified initiative and all of the costs we incurred were for the purpose of assuring the value of Monticello as a whole for the entire duration of its renewed operating license through 2013. This meant implementing LCM activities that were needed as we deferred upgrades to the initial equipment installed in the 1960s as well as for those upgrades that will reasonably need to be replaced in the next few years to support operations through the end of our extended license in 2030.

Nevertheless, I understand that in the certificate of need proceeding the costs were allocated to facilitate the Commission's review of alternatives. The result of that analysis was to apportion 58.4 percent to LCM activities and 41.6 percent to EPU activities. This apportionment was never used by the LCM/EPU Program team to manage the Program.

Q. DID YOU CONDUCT AN ANALYSIS TO BETTER ALLOCATE THE PROGRAM COSTS BETWEEN THE LCM AND EPU TASKS?

A. Yes. While I believe all costs should be considered integral to the plant as a whole, as part of this proceeding we analyzed what costs could have been avoided if we did not undertake the EPU. This 'avoided cost' analysis differs from rough allocation made during the certificate of need proceeding and focuses on what work was or would have been necessary over the course of Monticello's operations, and what work was avoidable if we did not undertake the EPU initiative. We identified three categories of costs from this analysis:

- EPU-only costs – costs that were solely related to the EPU, including licensing costs and EPU-specific equipment, and
- LCM-only costs – costs that were related to the LCM activities, and
- LCM costs that include some incremental EPU costs above what would have been spent for the LCM work.

Q. PLEASE DESCRIBE THE PROCESS YOU USED TO DETERMINE WHAT COSTS WOULD HAVE BEEN AVOIDABLE.

A. I have included a narrative description of my effort to assess the avoidable EPU costs as part of Exhibit ___ (TJO-1), Schedule 29. How each plant modification was categorized between LCM-only work and EPU-only work is shown in Exhibit ___ (TJO-1), Schedule 30. Using this analysis, 78.0 percent of the work was classified as unavoidable LCM that was needed to provide long-term benefits to the plant, and 22.0 percent of the work was classified as avoidable EPU costs. Mr. Alders uses this output in his analysis of the value of the incremental 71 MW associated with the EPU. To complete the record, Mr. Alders also uses the 41.6/58.4 percent levels from the certificate of need as a point of comparison.

Q. IS THE COMPANY SUPPLEMENTING IR OAG-48 DURING THE PROGRAM?

A. Yes. In our recently completed Minnesota retail rate case, we committed to provide an update to IR OAG-48. That update is attached as Exhibit ___ (TJO-1), Schedule 31.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I am proud of the work we did at Monticello. Through successful implementation of this Program, we have ensured the long-term availability of this important carbon-free baseload resource on the Xcel Energy system through 2030. Once the final NRC license amendments have been obtained for the EPU and the fuel configuration change, we will be able to increase Monticello's capacity from its current 600 MW to 671 MW through 2030. The plant as a whole, and the incremental additional capacity that the EPU captures provide a reasonable supply alternative for our customers, enhance fuel diversity within our portfolio, and operate as a hedge against historically volatile natural gas prices.

Nevertheless, I recognize that the cost of this initiative was much higher than we expected. While it is clear that we could have done a better job of estimating the actual costs of the initiative, I also believe the costs we incurred were necessary and important to the overall success of the Program.

Finally, I want to thank the Commission for this opportunity to provide a detailed summary of the LCM/EPU Program. This was a complicated endeavor, and the description we have provided is lengthy and complex and may raise issues for further inquiry. We are committed to assisting the Commission and its investigator, the Department, and parties in this review. We will do our best to answer stakeholders' questions and to provide the information the Commission needs to judge the prudence of our effort.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.